Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector

Technical Report Six: Costs of Producing Methanol from Unutilized Domestic Natural Gas

July 1991

**United States Department of Energy
Office of Policy, Planning and Analysis
Director, Resource Management
Washington, DC 20585**

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

CONTENTS

EXECUTIVE SUMMARY	viii
I. METHODOLOGY AND CONCLUSIONS	1
Introduction	1
Methodology for Evaluating Unutilized Gas	1
Conclusions Related to Small Remote Fields	2
Conclusions Related to Low-Btu Gas	4
Methodology for Evaluating Domestic Pipeline Gas	6
Conclusions Related to Domestic Pipeline Gas	6
II. LOWER 48 REMOTE GAS	9
Remote Gas Discoveries and Well Abandonments	9
Flaring and Venting of Natural Gas	9
Case Study of the Characteristics of Remote Gas Fields in Green River Basin, Wyoming	12
Introduction	12
Retrieval of Petroleum Information Well Data	13
Well Status	14
Creation of Remote Gas Categories for Economic Analysis	14
Economics of Development for Pipeline Sales	17
Economics of Development for Methanol Conversion	17
Comparative Economics of Methanol Option	20
Case Study of the Development of Remote Gas Resources: Saginaw Bay Pipeline, Michigan Basin	25
Introduction	25
Pipeline and Resource Description	27
Economics of Methanol Versus Pipeline Sales	28
III. DISTRIBUTION AND CHARACTERISTICS OF UNUTILIZED, LOW-QUALITY GAS	32
Introduction	32
Origin of Low-Quality Gas	32
Carbon Dioxide	32
Nitrogen	33
Hydrogen Sulfide	33
Distribution and Characteristics of Low-Quality Gases in the United States	33
Major Occurrences of Discovered, Nonproducing, Low-Quality Gas	35
Factors Affecting Economics of Production and Processing	36
Economic Scenarios	38
Economics of High-Carbon-Dioxide Gases	38
Economics of High-Nitrogen Gas	39
IV. CONVERSION OF DOMESTIC PIPELINE GAS TO METHANOL	45
Introduction	45

Availability and Cost of Gas	45
Facility Siting	45
Natural Gas Supply Procurement	46
Interruptible Gas Availability	47
Interruptible Gas Pricing	48
Projected Gas Prices	49
Spot Market Pricing Relationship	49
Projected Gas Feedstock Costs	50
Cost of Methanol Production	52
Capital Costs of Methanol Plant	52
Methanol Production Costs	52
Plantgate and Retail Prices	53
Price Comparisons with Imported Methanol	54
Conclusions	55

APPENDIX: COST OF PRODUCTION FOR SMALL-SCALE

U.S. REMOTE NATURAL-GAS-BASED METHANOL PLANTS	A-1
Introduction	A-1
Small-Scale Methanol Plant Design Concepts	A-1
Methanol Technology Review	A-1
Desulfurization	A-1
Steam Reforming	A-1
Methanol Synthesis	A-2
Methanol Purification	A-3
Small-Scale Methanol Concepts	A-3
Capital Cost	A-3
Maintenance	A-3
Modular Design	A-3
Self-Sufficiency	A-3
Automation	A-4
Liquid Effluents	A-4
Reforming	A-4
Heat Recovery	A-4
Compression	A-5
Methanol Synthesis	A-5
Synthesis Pressure	A-5
Converter Type	A-6
Methanol Distillation	A-6
Prototype Design	A-6
Design Bases	A-6
General	A-6
Process Design Basis	A-6
Process Description	A-7
Process Performance	A-9
Capital Costs	A-10
Basis	A-10
General	A-10
Investment Costs	A-10
Capital Cost Estimates	A-13
Costs of Production	A-14
Bibliography	A-25

TABLES

I-1	U.S. Plantgate Methanol Value Given Competing Gasoline Price	3
I-2	Energy Information Administration Retail Gasoline Price Forecast and Equivalent Methanol Plantgate Prices	4
I-3	Comparison of Cost of Methanol Made From U.S. Pipeline Gas Versus Gasoline and Imported Methanol for the Year 2000	8
II-1	State Regulations Regarding Temporary Well Abandonments	10
II-2	State Regulations Regarding Flaring and Venting of Casinghead Gas	11
II-3	Example of Energy Information Administration Report Showing Annual Dispensation of Natural Gas Production in 1988	12
II-4	Summary of Remote Potentially Productive Wells— Green River Basin, Wyoming	15
II-5	Development Cost Scenarios for Discovered Remote Rocky Mountain Gas Fields: Gas to Be Sold Through Pipeline	16
II-6	Gas Well Cash-Flow in Rocky Mountain Region Completing Existing Well: 500 Mcfd Case	18
II-7	Gas Well Cash-Flow in Rocky Mountain Region Drilling New Well: 500 Mcfd Case	19
II-8	Gas Well Cash-Flow in Rocky Mountain Region Completing Existing Well: 500 Mcfd Case	21
II-9	Gas Well Cash-Flow in Rocky Mountain Region Drilling New Well: 500 Mcfd Case	22
II-10	Methanol Conversion Scenarios for Discovered Remote Rocky Mountain Gas Fields	23
II-11	U.S. Plantgate Methanol Value Given Competing Gasoline Price	24
II-12	Energy Information Administration Retail Gasoline Price Forecast and Equivalent Methanol Plantgate Prices	25
II-13	Comparison of Value of Remote Gas as Methanol Feedstock Versus Pipeline Sales	26
II-14	Energy Information Administration Natural Gas Price Forecast	27
II-15	Saginaw Bay Pipeline Project, Michigan Basin	29
II-16	Methanol Conversion Scenarios for Discovered Remote Michigan Gas Fields	30
II-17	Comparison of Value of Remote Michigan Basin Gas as Methanol Feedstock Versus Pipeline Sales	31
III-1	Summary of Identified Major Occurrences of Discovered, Uneconomic, or Nonproducing Subquality Gas	37
III-2	Typical Composition and Resource Costs for Discovered Nonproducing Low-Quality Gas Areas	38
III-3	Amine Plants for Carbon Dioxide Removal	39
III-4	Comparison of Value of High-Carbon-Dioxide Gas as Methanol Feedstock Versus Pipeline Sales (30 percent CO ₂)	41
III-5	Cryogenic Plants for Nitrogen Rejection	42
III-6	Comparison of Value of High-Nitrogen Gas As Methanol Feedstock Versus Pipeline Sales (30 percent Nitrogen)	44
IV-1	Comparison of Gas Feedstock Consumption by 2,500 Ton-Per-Day Methanol Plant to Current Gas Consumption in Study Cities	46
IV-2	Curtailment Experience for Interruptible Pipeline Transportation	48
IV-3	Transportation Routing Assumptions and Actual 1989 Average Spot Gas Costs for Study Cities	50
IV-4	Natural Gas Wellhead Price Assumptions	51
IV-5	Projected Natural Gas Feedstock Costs for the Year 2000	52
IV-6	Cost of M85 With Methanol From U.S. Pipeline Gas for the Year 2000 Based on 2,500-STPD Methanol Plant	53

IV-7	Cost of M85 With Methanol From Foreign Countries for the Year 2000	54
IV-8	Comparison of Cost of Methanol Made From U.S. Pipeline Gas Versus Gasoline and Imported Methanol for the Year 2000	56
A-1	Capital Cost Breakdown in World-Scale Methanol Plants (Steam-Methane Reforming)	A-3
A-2	Advantages and Disadvantages of High-Pressure Synthesis	A-5
A-3	Natural Gas Feed Cases	A-7
A-4	Small-Scale Methanol Process Design Basis	A-8
A-5	Power Balance: 50 STPD	A-12
A-6	Fuel Balance: 50 STPD	A-13
A-7	Construction Costs for Modular Methanol Plant: Natural Gas Feed	A-13
A-8	Construction Costs for Offsites and Support Facilities for Modular Methanol Plant: Natural Gas Feed	A-14
A-9	Construction Costs for Modular Methanol Plant: High-CO ₂ Natural Gas Feed	A-14
A-10	Construction Costs for Offsites and Support Facilities for Modular Methanol Plant: High-CO ₂ Natural Gas Feed	A-15
A-11	Construction Costs for Modular Methanol Plant: High-Nitrogen Natural Gas	A-15
A-12	Construction Costs for Offsites and Support Facilities for Modular Methanol Plant: High-Nitrogen Natural Gas	A-15
A-13	Construction Costs for Conventional Methanol Plant: Natural Gas Feed	A-16
A-14	Modular Plant Costs of Production: Fuel-Grade Methanol, Natural Gas Feed	A-18
A-15	Modular Plant Costs of Production: Fuel-Grade Methanol, High-CO ₂ Feed	A-19
A-16	Modular Plant Costs of Production: Fuel-Grade Methanol, High-Nitrogen Feed	A-20
A-17	Conventional Plant Costs of Production: Fuel-Grade Methanol, Natural Gas Feed	A-21
A-18	Bases for Methanol Production Costs—Modular Plant Concept	A-22
A-19	Bases for Conventional Methanol Production Costs	A-23

FIGURES

I-1	Value of Remote Gas: Methanol Conversion Versus Pipeline Sales	5
I-2	Economics of Connecting Remote Gas: Pipeline Sales Versus Methanol Conversion	6
I-3	Value of Converting High-Nitrogen Gas to Methanol Versus Pipeline Sales	7
I-4	Value of Converting High-Carbon-Dioxide Gas to Methanol Versus Pipeline Sales	7
II-1	Map of Green River Basin, Wyoming	13
II-2	Map Showing Proposed Route of Saginaw Bay Pipeline	28
II-3	Saginaw Bay Pipeline Chronology	29
III-1	Distribution of Carbon Dioxide, Nitrogen, and Hydrogen Sulfide in the United States	34
III-2	Identified Significant Areas of Discovered, Nonproducing Subquality Gas	36
III-3	Cost of Carbon Dioxide Removal (1990\$/Mcf Sales Gas)	40
III-4	Cost of Nitrogen Removal (1990\$/Mcf Sales Gas)	43
IV-1	Hypothetical Seasonal Natural Gas Loads and Supply Availability (Winter Heating Season)	47
IV-2	Seasonal Variation in Spot Gas Wellhead Prices and Transportation Costs in the Lower Midwest Region	49
A-1	Modular Methanol Block-Flow Diagram	A-2
A-2	Modular Methanol Block-Flow Diagram	A-9

A-3	Reforming and Steam Generation—Process Flow Diagram	A-10
A-4	Methanol Synthesis and Distillation—Process Flow Diagram	A-11
A-5	Methanol Plant Construction Cost—Steam-Methane Reforming	A-17
A-6	Methanol Cost of Production	A-24

EXECUTIVE SUMMARY

As required by the Alternative Motor Fuels Act of 1988 (Public Law 10-494), Section 400EE, this report characterizes unutilized domestic natural gas and estimates the cost of converting this gas to methanol. Unutilized gas refers to:

- Remote gas, for which transportation costs restrict the sale of the gas.
- Low-Btu gas, for which processing costs make the gas uneconomic for pipeline use.

The report concludes that remote gas and low-Btu gas generally cannot be converted to methanol at costs near the expected competitive value of gasoline because of the poor economies of scale of small methanol plants. Moreover, the potential value of the gas as a pipeline-transported fuel would in nearly all

cases exceed its value as a methanol feedstock. Therefore, it is very unlikely that unutilized gas would be a significant source of methanol in the United States.

The report also estimates the cost of converting pipeline gas to methanol in a production facility located in a large methanol market. Costs are estimated for three representative U.S. metropolitan areas. The cost of domestically produced methanol is compared with the competitive price of gasoline and of imported methanol. Because of the expected high price of pipeline gas at the citygate, even when optimistic assumptions are made regarding favorable wellhead pricing and transportation terms, methanol made in large cities using pipeline gas is expected to be uneconomic compared with gasoline and compared with imported methanol.

I. METHODOLOGY AND CONCLUSIONS

INTRODUCTION

The Alternative Motor Fuels Act of 1988 (Public Law 100-494), Section 400EE states that the Secretary of Energy

shall study methanol plants, including the costs and practicability of such plants that are (A) capable of utilizing current domestic supplies of unutilized natural gas; (B) relocatable; or (C) suitable for natural gas to methanol conversion by natural gas distribution companies. For purposes of this subsection, the term "unutilized natural gas" means gas that is available in small remote fields and cannot be economically transported to natural gas pipelines, or gas the quality of which is so poor that extensive and uneconomic pretreatment is required prior to its introduction into the natural gas distribution system.

The purpose of this report is to characterize unutilized gas within the lower 48 States and to perform an economic analysis of methanol plants required by the act. The term "small remote fields" will be used to describe instances in which transportation economics restrict the use of the gas, as distinct from "low-Btu gas" for which processing costs are the major factor making the gas uneconomic for pipeline uses. Point (C) is interpreted to refer to the conversion of pipeline gas to methanol in a production facility located both on a gas pipeline and near a large market for methanol.

The approach with regard to unutilized lower 48 gas is to (1) compare the costs of converting such gas to methanol against the expected price of gasoline over the next 20 years, and (2) compare the economics of converting such gas to methanol against the economics of using the gas as a pipeline-transported fuel. The projections of national average gasoline prices and wellhead gas prices used in this evaluation came from the Energy Information Administration's (EIA) *Annual Energy Outlook 1990*. This study concludes that remote gas

and low-Btu gas generally cannot be converted to methanol at costs near the expected competitive value of gasoline because of the poor economies of scale of small methanol plants. Moreover, the potential value of the gas as a pipeline-transported fuel, in nearly all cases, would exceed its value as a methanol feedstock. Therefore, it is very unlikely that unutilized lower 48 gas would be a significant source of methanol in the United States.

With regard to point (C), this study estimated the cost of producing methanol from domestic pipeline gas in three representative U.S. metropolitan areas. That cost is compared with the competitive price of gasoline and imported methanol. Because of the expected high price of pipeline gas at the citygate (even when favorable wellhead pricing and transportation terms are optimistically assumed), methanol made in large cities using pipeline gas is expected to be uneconomic compared with gasoline or imported methanol.

METHODOLOGY FOR EVALUATING UNUTILIZED GAS

A major data source for the characterization of remote fields was the Petroleum Information Well History Control System (WHCS). It contains information on nearly all wells drilled in the United States, including date drilled, location, initial status (that is, exploratory or developmental) and final status (that is, dry hole, oil well, or gas well). A second source of information was oil and gas commissions of various States. Another important source was the Dwight's Gas Well Reports (GWR), which contains production information for gas wells throughout the United States, excluding the Appalachian States.

The WHCS was used to identify small, undeveloped remote gas fields. Exploratory dry holes that have tested significant gas flows, but were never completed and produced, were examined. The gas flows are recorded on a "drill stem test" (DST) as the exploratory well is

drilled or in a "production test" through casing. High DST gas flows on dry holes in remote areas generally are indications of uneconomic fields. Because of the high cost of searching and evaluating the data base, two areas were evaluated in detail as case studies: the Green River Basin in Wyoming and the Michigan Basin.

The hypothetical potential productivity of the wells was determined by examining the drill stem test information in the WHCS and the production history in the Dwight's GWR records of similar wells in the same area that *were completed for production*. Additional information for the Michigan Basin was obtained from the State.

The description of low-Btu gas resources came from data bases developed in a study sponsored by the Gas Research Institute to characterize gas composition of lower 48 discovered and undiscovered gas resources. As part of that study, known deposits of low-Btu gas were identified. Data sources included the WHCS, Dwight's GWR, literature searches, the gas analysis data base maintained by the Bureau of Mines, and an oil industry survey.

The estimated costs of producing gas from small remote fields and from low-Btu accumulations presented were calculated as constant dollars per thousand cubic feet (Mcf) of gas and converted to dollars per million Btu (MMBtu). The cost of developing and producing any gas field will depend on several factors, including drilling depth, size of accumulation, rate of production relative to reserves, and well productivity.

The factor costs for the economic evaluation come from various published sources and engineering estimates. The major source of drilling cost data is the *Joint Association Survey of Drilling Costs*, published by the American Petroleum Institute (API), and the *Expenditure Survey*, also published by API. Costs for well equipment and operating costs were obtained from estimates published by the Energy Information Administration.

Development costs were computed on a dollar-per-Mcf basis using a spreadsheet model developed for evaluating oil and gas exploration and development economics. The spreadsheet uses a standard discounted cash-flow

technique to determine the resource cost for gas, given a certain minimum rate of return, tax treatment, and royalties.

CONCLUSIONS RELATED TO SMALL REMOTE FIELDS

The characterization of small remote field gas includes:

- A discussion of State regulations that can affect the development of remote fields.
- The typical size of small remote gas fields, and typical well productivity within such fields.
- The typical development and production costs for such gas at the wellhead (that is, exclusive of mainline transportation costs) in constant dollars per MMBtu.
- The location and estimated number of such small remote fields in recent years in the two case study areas.

State safety and environmental regulations prohibit producers from maintaining nonproducing wells for long periods of time without cementing them in, which means that undeveloped gas fields found more than a year or so ago cannot be developed without redrilling wells. This raises the resource cost of the gas, making methanol production less economic when compared with recently drilled remote wells where the producer can complete the well and connect to a pipeline, abandon the well, or complete the well and use the gas for methanol feedstock.

The representative cases presented here show that incremental development costs for typical small remote fields containing from one to eight wells would range from \$2.49 to \$0.77 per MMBtu in cases where some or all of the wells have already been drilled and have not been plugged. When the wells have been plugged, development cost for the same example fields range from \$4.16 to \$1.61 per MMBtu. When the capital and operating costs of small-scale methanol conversion plants (sized to match each field) are added to these fuel costs, the resulting cost of methanol ranges from \$2.28 to \$0.71 per gallon for fields with wells not yet plugged and abandoned and \$2.59 to \$0.76 per gallon for abandoned fields.

The value of methanol in U.S. gas-field locations is computed for the year 1989 in Table I-1. This value is based on 1989 national average gasoline prices and assumes that methanol is blended into M85 (a mixture of 85 percent methanol and 15 percent gasoline) and that the M85 is sold at the pump on an energy-equivalent basis with gasoline. Differences in transportation, distribution, and taxes have been taken into account in computing the value of methanol.

Table I-2 shows the imputed methanol value given the projection of national average gasoline prices contained in the EIA *Annual Energy Outlook 1990*. The projected plantgate value of methanol, which reaches \$0.484 per gallon in 2010, is well below the costs of making it in remote U.S. locations (\$0.71 to \$2.59 per gallon). The primary reason the methanol is uneconomic is that the economies of scale in methanol plants make the small plants much more expensive than large plants.

This conclusion also is indicated by Figure I-1, which shows the natural gas wellhead

"netback" value, assuming that the gas is used to make methanol. The netback values are computed using various size methanol plants, ranging from 50 short tons per day (STPD), which uses 1.8 million cubic feet per day (MMcfd) of gas, to 2,500 STPD (91.2 MMcfd). The netback value is negative for all size plants through 1994. This means that even if the cost of the natural gas were zero, the methanol plants would be uneconomic. For the two smallest plants, the ones that would most typically be used for small remote fields, the netback value remains negative even to 2008.

The projected Rocky Mountain natural gas wellhead price for pipeline sales as derived from the EIA *Annual Energy Outlook 1990* also is shown in Figure I-1. In all years the value of the gas is higher for pipeline sales than for methanol conversion.

The difference in the value of the gas is shown in Figure I-2. In the year 2000, pipeline sales are worth \$2.81 per MMBtu more to the producer than conversion to methanol using a 200-STPD (6.84-MMcfd) plant. This difference

Table I-1 — U.S. Plantgate Methanol Value Given Competing Gasoline Price
(1989 dollars per gallon)

Gasoline		M85	
Gasoline Pump Price	\$1.060	Required M85 Pump Price (@ 1.74:1)	\$0.609
Federal Fuel Tax	\$0.090	Federal Fuel Tax	\$0.045
State Fuel Tax	\$0.090	State Fuel Tax	\$0.045
Sales Tax @ 5%	\$0.042	Sales Tax @ 5%	\$0.025
Total Taxes	\$0.222	Total Taxes	\$0.115
Pump Price Less Taxes	\$0.838	Pump Price Less Taxes	\$0.494
Outlet Markup	\$0.089	Outlet Markup	\$0.115
Trucking to Station	\$0.013	Trucking to Station	\$0.013
Terminal	\$0.016	Terminal	\$0.021
Total Distribution	\$0.118	Total Distribution	\$0.149
Wholesale Gasoline Price	\$0.721	Wholesale M85 Price	\$0.346
		Wholesale Gasoline Price	\$0.721
		Wholesale Methanol Price	\$0.279
		Trucking to Blender (100 miles)	\$0.030
		Plantgate Methanol Price	\$0.249

Source: Energy and Environmental Analysis report to DOE, "Capital and Operating Costs of a Fuel Methanol Distribution System—1988 Update," October 1988.

**Table I-2 — Energy Information Administration Retail Gasoline Price Forecast
and Equivalent Methanol Plantgate Prices**

Year	1989 Dollars per Gallon		1990 Dollars per Gallon	
	U.S. Average Retail Gasoline	Equivalent Methanol Plantgate	U.S. Average Retail Gasoline	Equivalent Methanol Plantgate
1989	1.06	0.249	1.11	0.261
1990	1.05	0.245	1.10	0.256
1991	1.06	0.251	1.11	0.262
1992	1.08	0.258	1.13	0.269
1993	1.09	0.264	1.14	0.276
1994	1.11	0.271	1.16	0.283
1995	1.12	0.278	1.17	0.290
1996	1.16	0.295	1.21	0.308
1997	1.19	0.312	1.25	0.326
1998	1.23	0.330	1.29	0.345
1999	1.27	0.349	1.33	0.365
2000	1.31	0.368	1.37	0.385
2001	1.33	0.378	1.39	0.396
2002	1.35	0.389	1.41	0.406
2003	1.37	0.399	1.44	0.417
2004	1.40	0.410	1.46	0.428
2005	1.42	0.421	1.48	0.440
2006	1.44	0.429	1.50	0.448
2007	1.46	0.438	1.52	0.457
2008	1.47	0.446	1.54	0.466
2009	1.49	0.455	1.56	0.475
2010	1.51	0.464	1.58	0.484
Growth Rate (percent)				
1990–1995	1.30	2.59	1.30	2.59
1995–2000	3.18	5.79	3.18	5.79
2000–2005	1.63	2.69	1.63	2.69
2005–2010	1.24	1.96	1.24	1.96

Source: *Annual Energy Outlook 1990*, DOE/EIA, January 1990.

grows to \$4.49 in 2010. Viewed another way, the producer would be willing to spend up to \$2.81 per MMBtu to build gathering and transport facilities to move the remote gas to a point where sales by pipeline could be made rather than make the gas into methanol *even if the producer could take advantage of some economies of scale by aggregating several remote fields into the 6.84 MMcf/d needed by the 200-STPD plant*. Assuming that the producer were gathering and transporting 2 MMcf/d from any one location, this \$2.81 per MMBtu would translate into 75 miles of gathering line, also shown in the figure. By 2010, the producer would hook up gas to a pipeline rather than make methanol, provided that 119 miles or less of line had to be built to the pipeline. If 4 MMcf/d

of gas were being transported from a given area, the justified pipeline distances would approximately double, to 150 miles in the year 2000 and 238 miles in 2010.

CONCLUSIONS RELATED TO LOW-BTU GAS

The characterization of low-Btu gas includes the following:

- The location and estimated size in billions of cubic feet (bcf) of known low-Btu gas in the lower 48 States.
- The typical chemical composition of low-Btu gas.

**Figure I-1 — Value of Remote Gas: Methanol Conversion
Versus Pipeline Sales**

Note: Pipeline sales value excludes costs of connecting to pipeline.

- The typical well productivities expected for such gas.
- The typical development and production costs for such gas at the wellhead, exclusive of processing costs.

Drawing on work sponsored by the Gas Research Institute, this report identifies several accumulations of low-Btu gas in the lower 48 States that together contain more than 135 trillion cubic feet (tcf) of raw gas. Methane and other hydrocarbons constitute roughly 10 percent of the total, or 13.5 tcf. The major contaminants in the gas are carbon dioxide, nitrogen, and hydrogen sulfide.

This study presents examples of the development options for some of this gas. The economics of developing the gas, exclusive of gas processing, vary from \$1.10 to \$7.68 per MMBtu for the accumulations for which estimates have been prepared. The cost of processing the gas to pipeline quality varies even more widely based on degree and type of contamination, volume of gas being processed,

and the value, if any, of byproduct credits (for example, sulfur, helium, and carbon dioxide).

This study examines two hypothetical gas types: one with 30 percent carbon dioxide and another with 30 percent nitrogen. The economics of processing the gases for pipeline sales were compared against conversion to methanol assuming a variety of plant sizes. As shown on Figures I-3 and I-4, some of the low-Btu gas could be economically processed into methanol in the late 1990's provided that the economies of scale of large methanol plants would be obtained. However, the value of the gas for pipeline sales is greater than conversion to methanol. For the high-nitrogen gas in the year 2000, the producer would net \$2.46 per MMBtu (after processing and gathering) for pipeline sales versus \$0.66 per MMBtu if the gas were converted to methanol in a 2,500-STPD (124.9 MMcfd raw gas) plant. By 2010 the advantage of pipeline sales grows to \$4.90 versus \$1.57 per MMBtu. For the high-carbon-dioxide gas, the pipeline option has an advantage of \$2.25 to \$1.00 per MMBtu in 2000 and

Figure I-2 — Economics of Connecting Remote Gas: Pipeline Sales Versus Methanol Conversion

an advantage of \$4.50 to \$2.02 per MMBtu in 2010.

METHODOLOGY FOR EVALUATING DOMESTIC PIPELINE GAS

The cost of producing methanol from domestic pipeline gas is estimated in three representative U.S. metropolitan areas (Atlanta, Chicago, and El Paso) for the year 2000, by which time there plausibly may exist a significant demand for methanol as an alternative transportation fuel in at least some metropolitan areas. The cost of domestically produced methanol is compared with the cost of gasoline and imported methanol.

To minimize the feedstock cost, a plant using domestic natural gas must be located close to a pipeline and, if possible, be able to purchase its feedstock under favorable price terms, such as those available by virtue of large volume

usage and willingness to accept interruptible service. To have a transportation cost advantage, the plant must be located near a major market for methanol. Moreover, the transportation advantage will be greatest for inland cities, because imported methanol will have to be transshipped by barge, rail, or truck, resulting in a higher price.

We examined the cost of producing methanol in Atlanta, Chicago, and El Paso. All three cities have access to pipeline gas and are inland. Moreover, all are serious or severe ozone nonattainment areas; consequently, methanol as a transportation fuel to reduce emissions may be considered for these cities. The cost of domestically produced methanol is compared with the gasoline price and the price of methanol imported from three prospective low-cost suppliers: Saudi Arabia, Qatar, and Argentina.

CONCLUSIONS RELATED TO DOMESTIC PIPELINE GAS

Adding together the capital charge, feedstock costs, and other operating costs gives plantgate costs in the year 2000 of \$0.62 per gallon of methanol produced in Chicago and El Paso and \$0.63 per gallon for Atlanta. This is the price f.o.b. at the production facility. The methanol plant is assumed to be located adjacent to a distribution terminal, so that no costs are incurred in moving the methanol from the methanol plant to an oil products terminal. Consequently, the wholesale price is equal to the plantgate price. Adding distribution costs, markup, and taxes gives a gallon-of-gasoline-equivalent pump price for M85 of \$1.64 for El Paso, \$1.65 for Chicago, and \$1.67 for Atlanta. These costs are summarized in Table I-3.

Domestically produced methanol must compete with gasoline to be economic. EIA projects the retail price of gasoline in the year 2000 to be \$1.31 per gallon, including all taxes. The methanol costs estimated for the year 2000 are 25 to 26 percent higher than the expected price of gasoline.

Domestic methanol must also be able to compete with imported methanol. There is an abundance of undeveloped natural gas reserves overseas that can be produced at prices well below the domestic gas price. The

Figure I-3 — Value of Converting High-Nitrogen Gas to Methanol Versus Pipeline Sales

Note: Pipeline sales value includes deduction for processing and gathering.

Figure I-4 — Value of Converting High-Carbon-Dioxide Gas to Methanol Versus Pipeline Sales

Note: Pipeline sales value includes deduction for processing and gathering.

**Table I-3 — Comparison of Cost of Methanol Made From U.S. Pipeline Gas
Versus Gasoline and Imported Methanol for the Year 2000**
(1989 dollars per gallon of gasoline-equivalent)

City	M85 with Methanol Made From U.S. Pipeline Gas	Gasoline *	M85 with Methanol from Foreign Countries **
Atlanta	\$1.67	\$1.31	\$1.31–1.49
Chicago	\$1.65	\$1.31	\$1.26–1.46
El Paso	\$1.64	\$1.31	\$1.55–1.72

* National average retail price from *Annual Energy Outlook 1990*, DOE/EIA, January 1990.

** Based on costs from Saudi Arabia, Qatar, and Argentina.

Department of Energy projects that methanol can be made from low-cost foreign gas in the year 2000 at a plantgate price under \$0.30 per gallon (1989 dollars), assuming that there is a large, stable market for the methanol. If the methanol is imported into a U.S. city near a port, the pump price for M85 would be under \$1.20 per gasoline-equivalent gallon. For some interior cities, however, M85 from imported methanol would be more expensive. The costs delivered to the three example cities are shown in Table I-3. In each case they are equal to or lower than M85 produced from domestic methanol.

This analysis is based on assumptions very favorable to the production of methanol from domestic natural gas. Even so, it would not be economic to produce methanol from domestic pipeline natural gas in the year 2000.

In estimating methanol production costs, the plant is assumed to generate revenue for at

least 15 years, so an investor considering construction of a methanol plant would wish to project feedstock prices for future years. Therefore, it is pertinent that EIA projects the price of natural gas to increase rapidly after the year 2000. The average U.S. wellhead price in 1989 dollars is projected to increase from \$3.23 per Mcf in 2000 to \$4.36 in 2005 and \$5.63 in 2010. The use of these higher projected prices would significantly increase the per-gallon feedstock costs and, consequently, raise the projected costs of producing methanol from domestic natural gas.

At the same time, because of the extensive low-cost natural gas reserves available overseas relative to the demand for this gas, the cost of imported methanol is expected to rise at a much slower pace than domestic gas prices. Consequently, methanol produced from domestic gas will be at an increasing price disadvantage relative to imported methanol.

II. LOWER 48 REMOTE GAS

REMOTE GAS DISCOVERIES AND WELL ABANDONMENTS

A major factor in the potential economic utilization of remote, nonproducing gas reservoirs is whether or not the "discovery" well can be re-entered and completed as a gas well. It is much more expensive to drill and complete a new well into such deposits than to complete an existing borehole. This is especially important for small deposits because many such reservoirs may need only one gas well to produce.

A well may be completed as an oil or gas well, plugged and abandoned, or temporarily abandoned. A plugged and abandoned well is filled with cement that would have to be drilled out to complete the well. Because a temporarily abandoned well contains only 50 feet or so of cement plugs at the producing zone, the operator can re-enter and complete it as a gas well at a later time at very little cost.

State regulatory agencies require operators to follow certain procedures when completing, plugging, or abandoning wells so that the abandoned well does not present a safety or environmental hazard and hydrocarbon reservoirs are not damaged. In general, an operator is allowed to temporarily abandon a well for a specified period of time, usually 6 months to a year, after which the operator must either produce or plug the well.

Table II-1 summarizes the regulations for temporary well abandonments for several producing States. The result of such regulations is that the great majority of remote, nonproducing wells have been plugged and abandoned. Thus, an economic analysis of producing and utilizing such gas deposits should be based upon either drilling and completing a new well (or wells) or re-entering a plugged and abandoned well.

FLARING AND VENTING OF NATURAL GAS

It is conceivable that remote (possibly developed) associated-dissolved gas might be a source of methanol feedstock when no outlet for the gas exists and it would otherwise have to be flared or vented. In general, State agencies do not allow the flaring or venting of gas-well or nonassociated gas. Casinghead gas (associated gas produced from oil wells) can be flared or vented under certain conditions. The quantities of flared or vented casinghead gas are substantial in certain areas, but individual wells generally produce such gas at low rates.

Table II-2 summarizes the regulations for flaring or venting casinghead gas for several producing States. Most States allow flaring for an indefinite period without special consideration, as long as the rate is below a specified value, which ranges from 25 to 100 thousand cubic feet per day. Louisiana does not allow any flaring without a State permit. New Mexico allows flaring without permit during the first 60 days after completion and requires a permit for further flaring. New Mexico also has a special provision that allows unrestricted flaring of gas from pre-1971 oil wells where gas-gathering systems are not in place.

State agencies may require an affidavit stating that the operator has made a diligent effort to market the gas and that the gas is uneconomic to market due to volume and price considerations.

If the expected daily production rate is above the specified maximum, a hearing may be required and the operator may be required to present more detailed information on why the gas is not marketable. For example, in Kansas, if the expected rate is above 25 Mcf per day, the commission will allow venting or flaring only

Table II-1 — State Regulations Regarding Temporary Well Abandonments

State	Approval Required To Temporarily Abandon a Well	Time Period After Drilling and Testing To Plug, Produce, or Obtain Permit	Base Time Period for Temporary Abandonment	Extensions Possible?
Arkansas	No	—	Indefinitely	—
Colorado	Yes	?	6 months	Yes, with approval; review each 6 months
Kansas	Yes	90 days	1 year	Yes, 1-year period
Montana	No	—	Indefinitely, if other wells are producing on lease	—
New Mexico	Yes	30 days	6 months	Yes, one extension for 1 year
Oklahoma	No	—	1 year if production casing is set	Yes, by written order or if other production on lease
Wyoming	Yes	?	Unspecified	Review of status each month

after the following factors have been considered:

- The availability of a market or pipeline facilities.
- Probable gas reserves.
- The necessity for re-injection of the gas to maintain reservoir pressure.
- Any anticipated change in the ratio of gas to oil.

Most States require operators to report estimated volumes of flared or vented casinghead

gas. In Colorado, volumes of flared gas are reported by lease on the standard monthly production report. New Mexico also requires all volumes to be reported. In Kansas, a report of flared volumes is required only when specified by the commission. Wyoming does not require such reporting.

EIA publishes in the *Natural Gas Annual* an estimate of the annual volume of gas that is flared or vented for each producing State. An example of these data is shown in Table II-3.

Table II-2 — State Regulations Regarding Flaring and Venting of Casinghead Gas

State	Allowed Maximum Rate of Flared or Vented Production Without Special Consideration (Mcf/d)	Upon Approval, Venting or Flaring Allowed in Special Cases Even if Rate Is Above Maximum	Factors To Be Considered for Approval of Such Flaring or Venting	Monthly Reporting Required for Flared or Vented Gas
Arkansas	2,000 cu. ft. per barrel of oil without penalty	Yes, but penalty assessed	<ul style="list-style-type: none"> • Sour gas flaring requires special approval • Gas having very poor quality can be flared at higher rates 	?
Colorado	50	?	<ul style="list-style-type: none"> • Not specified 	Yes
Kansas	25	Yes	<ul style="list-style-type: none"> • Market evaluation • Reserves determination • Need for reinjection • Anticipated change in GOR 	When specified
Louisiana	None	Yes	<ul style="list-style-type: none"> • Reason gas cannot be marketed economically 	?
Montana	100	Yes	<ul style="list-style-type: none"> • Reason for flaring • Gas analysis • Estimated reserves • Proximity to market • Expected gas price • Cost of marketing gas • ReInjection potential 	Yes, by lease
New Mexico	Not specified	Yes, flaring also allowed for pre-1971 oil wells if no gathering system	<ul style="list-style-type: none"> • Reason gas cannot be marketed economically 	Yes
Oklahoma	50. If hydrogen sulfide more than 100 ppm, must be flared	Yes, annual permit required	<ul style="list-style-type: none"> • Maximum volume expected • Reason gas cannot be marketed economically 	?
Wyoming	60	Yes	<ul style="list-style-type: none"> • Reason for flaring/venting • Estimated duration • Daily volume • Expected coproducts • Compositional analysis • Distance to sales point 	?

**Table II-3 — Example of Energy Information Administration Report
Showing Annual Dispensation of Natural Gas Production in 1988
(million cubic feet)**

State	Gross Withdrawals			Repressuring	Nonhydrocarbon Gases Removed	Vented and Flared	Marketed Production
	From Gas Wells	From Oil Wells	Total				
Alabama	168,484	6,570	175,054	23,444	20,262	1,824	129,524
Alaska	186,554	1,746,493	1,933,047	1,545,391	0	9,018	378,638
Arizona	0	179	179	0	0	123	56
Arkansas	146,898	43,780	190,678	22,994	0	1,110	166,573
California	156,767	295,110	451,877	88,868	832	2,733	359,444
Colorado	142,215	69,815	212,030	2,241	13,652	4,593	191,544
Florida	0	8,407	8,407	0	757	166	7,484
Illinois	1,157	181	1,338	0	0	0	1,338
Indiana	412	0	412	0	0	0	412
Kansas	481,600	96,215	577,815	963	0	578	576,274
Kentucky	73,629	0	73,629	0	0	0	73,629
Louisiana	4,607,205	641,000	5,248,205	45,103	0	22,835	5,180,267
Maryland	29	0	29	0	0	0	29
Michigan	85,013	66,796	151,809	2,340	0	3,324	146,145
Mississippi	222,539	14,640	237,180	38,948	68,667	5,512	124,053
Missouri	4	0	4	0	0	0	4
Montana	42,066	10,948	53,014	214	0	1,146	51,654
Nebraska	322	588	910	0	0	0	910
New Mexico	602,740	209,253	811,994	15,184	1,408	3,582	791,819
New York	26,423	1,044	27,467	0	0	4,012	23,455
North Dakota	225	66,093	66,318	0	5,800	2,771	57,747
Ohio	166,690	0	166,690	0	0	0	166,690
Oklahoma	1,699,601	407,031	2,106,632	0	0	0	2,106,632
Oregon	4,000	0	4,000	0	0	0	4,000
Pennsylvania	167,089	0	167,089	0	0	0	167,089
South Dakota	1,034	3,248	4,283	363	0	0	3,920
Tennessee	0	2,100	2,100	0	0	0	2,100
Texas	5,518,260	1,400,362	6,918,622	456,627	144,134	31,832	6,286,029
Utah	174,421	103,489	277,910	174,772	0	1,766	101,372
Virginia	18,682	0	18,682	0	0	258	18,424

CASE STUDY OF CHARACTERISTICS OF REMOTE GAS FIELDS IN GREEN RIVER BASIN, WYOMING

Introduction

To evaluate the economics of producing natural gas from remote, unutilized gas deposits, an area was chosen for a case study that would locate wells that have found such deposits and would determine or estimate char-

acteristics such as depth, distance from a pipeline, and ultimate recovery. From this information, realistic scenarios can be developed to model or characterize these deposits.

The Green River Basin in southwest Wyoming was selected for a case study. It is a heavily gas-prone basin and is a major supply area for the Rocky Mountain region. Figure II-1 is an oil and gas field map of the basin. Gas fields are shown in gray, while oil fields are black. During

Figure II-1 — Map of Green River Basin, Wyoming

Source: "Oil and Gas Map of Wyoming, 1984," The Geological Survey of Wyoming.

the exploration "boom" of the late 1970's and early 1980's, the Green River Basin was the site of a large exploration effort, primarily for relatively deep, stratigraphically trapped gas reservoirs in the Upper Cretaceous section. Shallow producing areas of the basin, including the Rock Springs Uplift, have been relatively well explored, while deeper areas of the basin remain sparsely drilled and are believed to hold vast quantities of gas contained in Upper Cretaceous tight sands.

Figure II-1 shows that gas production is widespread across the basin, and a large pipeline and gathering line network exists. The major east-west pipelines are operated by Colorado Interstate Gas, Questar, and Northwest Central. Although the pipeline network is extensive, there are very large areas without production.

Much of the currently nonproductive area of the Green River Basin contains gas deposits and probably will be productive eventually.

Retrieval of Petroleum Information Well Data

A computer search of Petroleum Information (P.I.) historical well data was conducted to locate remote, undeveloped, nonproducing wells (reservoirs). The P.I. historical well file contains information such as the initial well status, final well status, completion date, total depth, and production and formation test data. One of the "final status" designations is "temporarily abandoned" well, making it possible to evaluate the *current* number of temporarily abandoned wells in a particular State or basin. Unfortunately, wells that were classified as

temporarily abandoned at some point in the past cannot be determined from P.I. data.

To evaluate how many nonproducing wells were temporarily abandoned at some point, it would be necessary to research the historical State permitting records. Because most States apparently keep only hardcopy well files, this would be difficult. There are probably a few States that have this information in data-base form, and it may be worthwhile to pursue such a possibility. Such a research effort could lead to an estimate of the percentage of current dry holes in gas-prone areas that were at one time believed to be gas discoveries.

The Green River Basin well retrieval was made by specifying the following parameters:

- State of Wyoming.
- Townships 12 to 28 North.
- Ranges 90 to 111 West.
- Initial class: new field wildcat.
- Final status: dry hole, suspended, or temporarily abandoned.
- Gas to surface on a formation test or gas recovery on a production test.

A total of 172 wells met these criteria, and data on them were retrieved. The test data were evaluated for all of these wells to select only those wells believed to be potential producers. A minimum cutoff value of 100 Mcfd from a production test was applied. A total of 34 wells were selected and are shown in Table II-4.

The table shows the well name, location, current status, completion date, tested formation, depth of test or gas show, expected maximum production rate in Mcfd, and the approximate distance to a pipeline connection.

The pipeline connection distance on the *current* system was determined by locating the wells on the oil and gas field map. The distance was measured from the nearest pipeline or the nearest active field. The table shows that this distance ranged from 0 to 21 miles, with a typical distance of 2 to 5 miles. Since pipeline and gathering systems are consistently expanding, it should be noted that pipeline distances may have been greater at the time the wells were drilled.

Well Status

Most of the wells have a final status of "D&A," or "drilled and abandoned." This means that the well has been plugged with cement and cannot be re-entered without an expensive workover. Of the 34 wells considered potential producers, only 3 had a "TA," or "temporarily abandoned," status. This means that the well has not been plugged and can easily be re-entered for completion as a gas well. The completion dates in these wells indicate that the wells were drilled from 5 to 21 years ago, which raises the question of whether these wells still are temporarily abandoned. Of the original retrieval of 172 wells, only 10 currently are classified as temporarily abandoned.

What is not known is how many of the "D&A" wells were classified as "TA" at some time in the past. In other words, the status carried by P.I. is the current or final status, and previous designations are lost. In addition, it has been 5 to 10 years since there was a large amount of new field wildcat drilling in the basin. Because drilling activity has slowed down in recent years, the current number of temporarily abandoned wells is small.

In summary, there are very few new field "discovery" wells in the basin that currently are classified as temporarily abandoned and could be easily re-entered and completed as gas wells. Most of the wildcat dry holes with good gas shows have been plugged and abandoned. During a period of active new field exploration, however, the "current" number of temporary abandonments available for low-cost completion will increase.

Creation of Remote Gas Categories for Economic Analysis

The most important variables affecting the resource costs of these remote gas deposits are the following:

- Per-well ultimate recovery.
- Per-well gas deliverability through time.
- Depth of production (effect on drilling and completion costs).
- Gas composition.

**Table II-4 — Summary of Remote Potentially Productive Wells—
Green River Basin, Wyoming**

Well	Location	Status	Comp. Date	Formation	Depth	Max. Rate (Mcf/d)	Distance to Connection (miles)
1 Gulf 1 Unit	11 12N 94W	D&A	11/58	Frontier	3,060	975	0.0
2 Pan American 1 Unit	4 12N 96W	D&A	10/59	Lance	9,000	1,984	4.0
3 Davis Oil 1 Polaris	26 13N 95W	D&A	1/81	Lewis	12,320	360	5.0
4 Caulkins 1-9W Federal	9 14N 100W	D&A	9/62	Blair	7,730	3,500	6.0
5 Phoenix 16-1 Kent Ranch	16 14N 101W	D&A	4/78	Blair	6,380	166	7.0
6 Tom Brown 1 Current Cr.	20 14N 108W	D&A	4/76	Frontier	16,890	500	1.0
7 Santa Fe 1-10 Flattop	10 15N 93W	D&A	3/82	Ericson	9,700	500	4.0
8 Enstar 5 Windmill Draw	21 15N 94W	TA	9/82	Almond/Lewis	11,000	500	1.0
9 TXO 2 Windmill Draw	30 15N 94W	D&A	9/78	Mesaverde	13,100	1,300	2.0
10 Nova 18-1 Muddy Creek	18 17N 91W	D&A	10/87	Almond	5,600	134	1.0
11 Amoco Champlin 336	21 17N 94W	D&A	5/79	Ericson	10,980	129	1.5
12 Humble 1 Unit	26 18N 110W	D&A	2/62	Mesaverde	9,090	115	2.0
13 Amoco 1 Fillmore Cr.	1 19N 92W	D&A	6/78	Lewis	8,500	200	0.5
14 Union 1-C-19	19 19N 105W	D&A	5/72	Dakota	14,990	865	2.0
15 Davis 1 Poitevent	28 19N 106W	Gas	10/78	Dakota	15,300	2,000	4.0
16 Davis 1 Sue Fed.	32 19N 106W	Gas	5/79	Frontier	14,650	332	3.0
17 Cities 1 Fed. Y	32 20N 91W	D&A	7/78	Mesaverde	9,300	838	3.0
18 HPC 1 Dines	7 20N 105W	D&A	11/81	Weber	17,000	1,500	1.0
19 Amoco 3 Monument Lake	29 22N 92W	D&A	2/81	Almond	12,300	500	4.0
20 Amoco 1 Horseshoe Bend	15 22N 96W	D&A	7/75	?	9,950	150	0.5
21 HPC 12 Great Divide	26 23N 96W	TA	1/85	Lewis	9,880	300	2.0
22 Ohio 1 Unit	12 23N 98W	D&A	1/59	Almond	9,090	2,031	6.3
23 Mountain Fuel 1 Windmill	33 23N 106W	D&A	12/64	Frontier	7,170	1,020	13.5
24 Kansas Nebraska 1 Sandy Bend	14 23N 108W	Gas	7/75	Frontier	15,090	264	16.0
25 Woods Petroleum 1 Saddle Bag	22 24N 100W	D&A	10/82	Muddy	16,325	584	20.0
26 HO&M 44-24	24 24N 104W	Gas	11/80	Frontier	9,550	850	4.0
27 Chorney 1 Lombard Canyon	25 25N 108W	Sus	1/71	Mesaverde	8,630	802	16.0
28 Mtn. Fuel 1 Cyclone Rim	14 26N 96W	D&A	9/73	Mesaverde	15,650	156	4.5
29 Pan Amer. 1A Huber	11 26N 111W	D&A	11/64	Frontier	4,650	1,500	4.5
30 O&G Futures 1 Govt.	33 27N 91W	D&A	5/64	Mesaverde	7,530	250	1.0
31 Skelly 1 Lost Creek	34 27N 93W	D&A	5/74	Nugget	10,900	595	0.5
32 Reasor 1 Govt.	28 27N 103W	D&A	8/60	Lance	9,520	150	21.0
33 Davis 1 Sugar Loaf	7 27N 109W	D&A	12/78	Frontier	15,650	150	11.0
34 True 41-27	27 28N 111W	TA	10/69	Mesaverde	5,880	300	4.0
Averages					10,568	750	5.2

Note: Potentially productive wells are dry or temporarily abandoned wildcat wells testing gas at significant rates.

D&A = drilled and abandoned.

TA = temporarily abandoned.

- Number of productive wells (determines field deliverability and ultimate recovery).
- Distance to connection from field or well.
- Amount of gathering line required for each field.

The economic analysis is based upon producing the gas from one reservoir (field) with one or more wells. Not considered here is a scenario where several remote gas fields are tied together and a single pipeline is built to connect the gas to a regional line.

The goal was to evaluate a group of scenarios for remote gas occurrence in this basin that would include typical or realistic values for the key variables. Such typical values have been selected based upon the analysis of the P.I. dry holes and of the Dwight's Gas Well Reports data on well productivities in the basin. Table II-5 lists the 27 scenarios evaluated. Initial production rate values of 500 Mcfd, 750 Mcfd, and 1,000 Mcfd were used. All scenarios have the same reservoir depth of 10,000 feet.

**Table II-5 — Development Cost Scenarios for Discovered Remote Rocky Mountain Gas Fields:
Gas To Be Sold Through Pipeline**

Scenario	Initial Per Well Production (Mcf/d)	Wells Per Field	Distance From Field to Pipeline (miles)	Wellhead Gas Cost (1990\$/MMBtu)*	Field Gathering			Pipeline Connection Gathering			Total Gas Cost for Pipeline Sales (1990\$/MMBtu)
					Miles of Line**	Total Cost (1990\$)	Unit Cost (1990\$/MMBtu)	Diameter (inches)	Total Cost (1990\$)	Unit Cost (1990\$/MMBtu)	
1	500	1	5	1.04 - 2.73	0.1	5,280	0.01	4	369,600	0.75	1.80 - 3.49
2	500	4	5	1.89 - 2.73	4.0	211,200	0.11	4	369,600	0.19	2.18 - 3.03
3	500	8	5	2.10 - 2.73	9.5	501,600	0.13	4	369,600	0.09	2.32 - 2.95
4	500	1	10	1.04 - 2.73	0.1	5,280	0.01	4	739,200	1.50	2.56 - 4.25
5	500	4	10	1.89 - 2.73	4.0	211,200	0.11	4	739,200	0.38	2.37 - 3.21
6	500	8	10	2.10 - 2.73	9.5	501,600	0.13	4	739,200	0.19	2.41 - 3.05
7	500	1	25	1.04 - 2.73	0.1	5,280	0.01	4	1,848,000	3.76	4.81 - 6.50
8	500	4	25	1.89 - 2.73	4.0	211,200	0.11	4	1,848,000	0.94	2.93 - 3.78
9	500	8	25	2.10 - 2.73	9.5	501,600	0.13	4	1,848,000	0.47	2.69 - 3.33
10	750	1	5	0.69 - 1.82	0.1	5,280	0.01	4	369,600	0.50	1.20 - 2.33
11	750	4	5	1.26 - 1.82	4.0	211,200	0.07	4	369,600	0.13	1.45 - 2.02
12	750	8	5	1.40 - 1.82	9.5	501,600	0.09	4	369,600	0.06	1.54 - 1.97
13	750	1	10	0.69 - 1.82	0.1	5,280	0.01	4	739,200	1.00	1.70 - 2.83
14	750	4	10	1.26 - 1.82	4.0	211,200	0.07	4	739,200	0.25	1.58 - 2.14
15	750	8	10	1.40 - 1.82	9.5	501,600	0.09	6	1,056,000	0.18	1.66 - 2.08
16	750	1	25	0.69 - 1.82	0.1	5,280	0.01	4	1,848,000	2.51	3.20 - 4.33
17	750	4	25	1.26 - 1.82	4.0	211,200	0.07	4	1,848,000	0.63	1.95 - 2.52
18	750	8	25	1.40 - 1.82	9.5	501,600	0.09	6	2,640,000	0.45	1.93 - 2.35
19	1,000	1	5	0.52 - 1.36	0.1	5,280	0.01	4	369,600	0.38	0.90 - 1.74
20	1,000	4	5	0.94 - 1.36	4.0	211,200	0.05	4	369,600	0.09	1.09 - 1.51
21	1,000	8	5	1.05 - 1.36	9.5	501,600	0.06	6	528,000	0.07	1.18 - 1.49
22	1,000	1	10	0.52 - 1.36	0.1	5,280	0.01	4	739,200	0.75	1.28 - 2.12
23	1,000	4	10	0.94 - 1.36	4.0	211,200	0.05	4	739,200	0.19	1.18 - 1.60
24	1,000	8	10	1.05 - 1.36	9.5	501,600	0.06	6	1,056,000	0.13	1.24 - 1.56
25	1,000	1	25	0.52 - 1.36	0.1	5,280	0.01	4	1,848,000	1.88	2.41 - 3.25
26	1,000	4	25	0.94 - 1.36	4.0	211,200	0.05	4	1,848,000	0.47	1.46 - 1.88
27	1,000	8	25	1.05 - 1.36	9.5	501,600	0.06	6	2,640,000	0.34	1.44 - 1.76

* All cases assume wells drilled to 10,000 feet. Lower end of costs assumes some wells are drilled but not completed, while upper end of costs assumes all new wells must be drilled. Assumes normal production pattern over 20 years.

** Field gathering done with 3-inch line.

The reservoirs that have been found and abandoned are very likely small in area, typically several square miles. The analysis included a range of one to eight wells to develop a reservoir (on a 320-acre spacing). The four- and eight-well fields will require 4 and 9.5 miles of field gathering lines, respectively. The three scenarios for the distance to a pipeline connection are 5, 10, and 25 miles.

Economics of Development for Pipeline Sales

Table II-5 shows the economics of developing gas from remote Green River Basin (or other Rocky Mountain) locations, given the assumptions in the 27 scenarios. The wellhead cost of the gas is shown in the fifth column in 1990 dollars per MMBtu. For the first scenario, which is based on a one-well field with an initial well production rate of 500 Mcfd, the wellhead gas resource cost ranges from \$1.04 to \$2.73 per MMBtu. The first cost assumes that a well has been drilled but has not yet been completed for production. The second cost assumes that the original well has been plugged and abandoned and that a new well must be drilled. The methodology for computing these wellhead resource costs is shown in Table II-6 for the existing-well case and in Table II-7 for the new-well case.

The factor costs for the economic evaluation come from various published sources and engineering estimates made by Energy and Environmental Analysis. The major source of drilling cost data was the *Joint Association Survey of Drilling Costs*, published by the American Petroleum Institute (API) and the *Expenditure Survey* also published by API. Costs for well equipment and operating costs were obtained from estimates published by the Energy Information Administration. Development costs were computed on a dollar-per-Mcf basis using a standard discounted cash-flow technique, given a certain minimum rate of return, tax treatment, and royalties. Based on 1988 factor costs (the last year now available) the resource cost for the new-well example shown in Table II-7 is \$2.90 per Mcf which, accounting for the Btu content of the gas plus the heat content of the lease condensate, translates into \$2.50 per MMBtu. This cost is increased to \$2.73 per MMBtu in 1990 dollars using the GNP deflator.

The resource cost for the new-well case of \$2.73 per MMBtu is the same for the four-well and eight-well field scenarios. The existing-well case is different among the fields in that the one-well field is \$1.04, the four-well field is \$1.89, and the eight-well field is \$2.10 per MMBtu. These differences stem from the assumption that only two wells already exist in the unabandoned four-well field and three in the eight-well field. It is highly improbable that the four- and eight-well remote fields would be fully drilled before the outlet for the gas was known, and therefore anyone developing the fields would need to drill some new wells.

Field-gathering assumptions are shown in columns six to eight of Table II-5. Field gathering refers to the connecting of the wells in a field to a central processing and measurement point. Column six shows the length of (3 inch) gathering line assumed for each field size and column seven shows its installed cost at \$10 per foot. The next column translates the field gathering costs to dollars per MMBtu. Field gathering costs range from \$0.01 to \$0.13 per MMBtu in these scenarios.

The next set of columns lays out the assumptions for gathering line from the central measurement point of the field to the pipeline. The scenarios were developed under the assumption that the fields could be 5, 10, or 25 miles from the pipeline. Depending on the flow rates from the wells and the distance to the pipeline, either four or six inch pipe would be laid at a cost of \$14.00 or \$20.00 per foot, respectively. For the scenarios presented here, pipeline connection gathering costs range from \$0.07 to \$3.76 per MMBtu.

The final columns of Table II-5 show the total cost of the gas delivered to the pipeline. This is derived by adding together the wellhead cost, field gathering cost, and pipeline connection cost.

Economics of Development for Methanol Conversion

Developing a remote gas field as a feedstock source for a specific, dedicated methanol plant would be different from developing it for pipeline sales. The major difference is that the field probably would be developed more slowly and would be operated for a shorter period of time,

Table II-6 — Gas Well Cash-Flow in Rocky Mountain Region Completing Existing Well: 500 Mcfd Case

Cost and Financial Assumptions						Tax Scenario					
Region # =	8					<u>Write Off Schedules</u>					
Drilling Depth =	10,000	Sev & Ad Val Taxes =	10.1%			Deprec.	Intang.	Tax =	37.3%		
Drilling Interval =	6	Royalty =	12.5%			0.14	0.700	ITC =	0.0%		
\$/Ft Succ Well =	77.0	After-Tax, Real ROR =	10.0%			0.25	0.060				
\$/Ft Dry Hole =	36.3	Inflation =	4.0%			0.17	0.060	INTG % =	70.0%		
\$/Succ Well =	192,500					0.13	0.060				
\$/Dry Hole =	0	Success Rate =	76.0%			0.11	0.060				
Stimul \$/Well =	63,250	MMcf/Well =	1,559			0.10	0.060				
Equip/W =	37,500	Btu/cf Dry Gas =	1,130			0.10	0.000				
O+M/Year =	26,500	Condnsite (Bbl/MMcf) =	7.0	Takes =	0.900						
G&G/Well =	0										
Lease/Well =	0										
Overhead, G&A% =	16.0%										
		1988\$	1990\$								
\$/Mcf Raw Gas =	\$1.10	\$1.20									
\$/MMBtu Gas & Condnsite =	\$0.95	\$1.04									
		Deprec.	Intang.	Deplet.	Expen.*	Total					
		95,250	198,000	0	46,920	340,170					
Year	GNP Deflator			After-Tax Annual			Gas Prod. (MMcf/Y)	Gas Value \$/Mcf	Net Rev. A.T.	Net A.T. Cashflow	Gas Prod. Mcfd
1	1.000	(90,276)	(146,302)	0	(46,034)	(282,613)	82.8	1.10	44,197	(238,415)	227
2	1.040	8,540	4,261	0	(16,616)	(3,814)	182.4	1.10	97,384	93,570	500
3	1.082	5,584	4,097	0	(16,616)	(6,934)	128.2	1.10	68,444	61,510	351
4	1.125	4,106	3,939	0	(16,616)	(8,570)	99.5	1.10	53,132	44,562	273
5	1.170	3,341	3,788	0	(16,616)	(9,487)	82.1	1.10	43,840	34,353	225
6	1.217	2,920	3,642	0	(16,616)	(10,053)	70.3	1.10	37,511	27,458	193
7	1.265	2,808	0	0	(16,616)	(13,808)	61.6	1.10	32,890	19,082	169
8	1.316	0	0	0	(16,616)	(16,616)	55.0	1.10	29,350	12,734	151
9	1.369	0	0	0	(16,616)	(16,616)	49.7	1.10	26,542	9,927	136
10	1.423	0	0	0	(16,616)	(16,616)	45.4	1.10	24,256	7,641	124
11	1.480	0	0	0	(16,616)	(16,616)	41.9	1.10	22,356	5,740	115
12	1.539	0	0	0	(16,616)	(16,616)	38.9	1.10	20,748	4,133	106
13	1.601	0	0	0	(16,616)	(16,616)	36.3	1.10	19,370	2,754	99
14	1.665	0	0	0	(16,616)	(16,616)	34.0	1.10	18,173	1,557	93
15	1.732	0	0	0	(16,616)	(16,616)	32.1	1.10	17,124	508	88
16	1.801	0	0	0	(16,616)	(16,616)	30.3	1.10	16,196	(419)	83
17	1.873	0	0	0	(16,616)	(16,616)	28.8	1.10	15,369	(1,246)	79
18	1.948	0	0	0	(16,616)	(16,616)	27.4	1.10	14,627	(1,988)	75
19	2.026	0	0	0	(16,616)	(16,616)	26.1	1.10	13,958	(2,658)	72
20	2.107	0	0	0	(16,616)	(16,616)	25.0	1.10	13,350	(3,266)	69
					SUM NPV	(551,281) (350,353)	1,178 656		628,817 350,353	77,536 0	

Table II-7 — Gas Well Cash-Flow in Rocky Mountain Region Drilling New Well: 500 Mcfd Case

Cost and Financial Assumptions							Tax Scenario				
Region #	=	8	Sev & Ad Val Taxes	=	10.1%		<u>Write Off Schedules</u>			Tax	= 37.3%
Drilling Depth	=	10,000	Royalty	=	12.5%		Deprec.	Intang.		ITC	= 0.0%
Drilling Interval	=	6	After-Tax, Real ROR	=	10.0%		0.14	0.700			
\$/Ft Succ. Well	=	77.0	Inflation	=	4.0%		0.25	0.060		INTG %	= 70.0%
\$/Ft Dry Hole	=	36.3					0.17	0.060			
\$/Succ. Well	=	770,000	Success Rate	=	76.0%		0.13	0.060			
\$/Dry Hole	=	363,283	MMcf/Well	=	1,559		0.11	0.060			
Stimul \$/Well	=	63,250	Btu/cf Dry Gas	=	1,130		0.10	0.060			
Equip/W	=	37,500	Condns (Bbl/MMcf)	=	7.0	Takes = 0.900	0.10	0.000			
O+M/Year	=	26,500									
G&G/Well	=	25,000									
Lease/Well	=	50,000									
Overhead, G&A%	=	16.0%									
		<u>1988\$</u>	<u>1990\$</u>								
\$/Mcf Raw Gas	=	\$2.90	\$3.16								
\$/MMBtu Gas & Condns	=	\$2.50	\$2.73								
		Deprec.	Intang.	Deplet.	Expen.*	Total					
		268,500	602,250	98,684	288,186	1,257,620					
Year	GNP Deflator			After-Tax Annual			Gas Prod. (MMcf/Y)	Gas Value \$/Mcf	Net Rev. A.T.	Net A.T. Cashflow	Gas Prod. Mcfd
1	1.000	(254,479)	(445,003)	(96,730)	(197,308)	(993,519)	82.8	2.90	116,327	(877,192)	227
2	1.040	24,075	12,960	4,141	(16,616)	24,560	182.4	2.90	256,314	280,875	500
3	1.082	15,741	12,461	2,798	(16,616)	14,386	128.2	2.90	180,144	194,530	351
4	1.125	11,574	11,982	2,089	(16,616)	9,030	99.5	2.90	139,844	148,874	273
5	1.170	9,417	11,521	1,657	(16,616)	5,980	82.1	2.90	115,385	121,366	225
6	1.217	8,232	11,078	1,363	(16,616)	4,058	70.3	2.90	98,730	102,788	193
7	1.265	7,915	0	1,150	(16,616)	(7,551)	61.6	2.90	86,566	79,015	169
8	1.316	0	0	986	(16,616)	(15,629)	55.0	2.90	77,248	61,619	151
9	1.369	0	0	858	(16,616)	(15,758)	49.7	2.90	69,859	54,102	136
10	1.423	0	0	754	(16,616)	(15,862)	45.4	2.90	63,843	47,981	124
11	1.480	0	0	668	(16,616)	(15,948)	41.9	2.90	58,840	42,893	115
12	1.539	0	0	596	(16,616)	(16,019)	38.9	2.90	54,609	38,590	106
13	1.601	0	0	535	(16,616)	(16,080)	36.3	2.90	50,980	34,900	99
14	1.665	0	0	483	(16,616)	(16,133)	34.0	2.90	47,831	31,698	93
15	1.732	0	0	437	(16,616)	(16,178)	32.1	2.90	45,070	28,892	88
16	1.801	0	0	398	(16,616)	(16,218)	30.3	2.90	42,628	26,410	83
17	1.873	0	0	363	(16,616)	(16,253)	28.8	2.90	40,451	24,199	79
18	1.948	0	0	332	(16,616)	(16,283)	27.4	2.90	38,499	22,215	75
19	2.026	0	0	305	(16,616)	(16,311)	26.1	2.90	36,736	20,426	72
20	2.107	0	0	280	(16,616)	(16,335)	25.0	2.90	35,137	18,802	69
					SUM	(1,152,064)	1,178		1,655,044	502,980	
					NPV	(922,128)	656		922,128	(0)	

corresponding to the physical or economic life of the plant. The specific development pattern would depend on the development costs of the field, the methanol plant's capital and operating costs and expected life, expected future methanol prices, and the discount rate of the producer.

For purposes of this analysis, it is assumed that the methanol plant's life would be 15 years and that the wells would be drilled and operated so as to supply the plant at a constant rate of gas for as long as feasible. For the eight-well fields, this means four wells are drilled before the plant begins operation and one well is drilled in the 4th, 6th, 8th, and 11th years. For the four-well fields, two wells are drilled immediately and one each in the fourth and ninth year. The wells are throttled back in their early years to about two-thirds of normal production rates and will be operated, on average, about twelve years. The impact this has on the wellhead costs is shown in Tables II-8 and II-9. The 500 Mcfd well now is produced at 333 Mcfd initially and has a resource cost of \$1.11 per MMBtu for an unabandoned case and \$3.08 per MMBtu for the new-well case. These are 6.7 percent and 12.8 percent higher than the costs for the "normal production" rates assumed for pipeline sales.

For the one-well field, production must be restricted even more severely if the methanol plant is to be supplied at a nearly constant rate over 15 years. The 500 Mcfd well would be produced at 167 Mcfd and would have a resource cost of \$1.52 and \$4.14 per MMBtu. These costs are 46 percent and 52 percent higher than those of the "normal production" rates.

Table II-10 summarizes the methanol conversion option for the hypothetical remote field scenarios. Because distance to the pipeline is not relevant, there are just nine scenarios here versus the 27 in the pipeline sales option. The wellhead resource cost, as was explained, is higher here than shown on Table II-5 for pipeline sales because the wells are produced at a slower rate and for a shorter number of years. For the same reasons, the cost of field gathering is higher on a dollar-per-MMBtu basis.

The methanol plants are sized to the individual fields based on the maximum productive

capacity the fields can sustain over the 15-year plant life (shown in column labeled Plant Capacity: MMcf/d). The plant capacity also is shown in short tons of methanol per day (STPD). The plants matching the remote fields range in size from 4.9 STPD to 78 STPD. By way of comparison, a "world class" methanol plant would be 5,000 STPD or larger.

The nonfeedstock cost of producing methanol is derived from a study by Chem Systems, Inc. (which is the basis for this report's appendix). The study evaluated modular methanol plants sized 50, 100, 200, and 300 STPD. The nonfeedstock methanol costs in Table II-10 are based on a cost curve fit to those data. *Because no estimates were made for plants smaller than 50 STPD, the cost presented in the table for the very small plants should be treated with caution.* The nonfeedstock cost of the methanol ranges from \$0.57 per gallon for a 78-STPD plant to \$2.09 per gallon for the 4.9-STPD plant. Total costs for the methanol, including natural gas figured at 0.1198 MMBtu per gallon, range from \$0.71 per gallon to \$2.59 per gallon.

Comparative Economics of Methanol Option

The value of methanol in U.S. gas-field locations is computed for the year 1989 in Table II-11. This value is based on data on 1989 national average gasoline prices and assumes that methanol is blended into M85 (a mixture of 85-percent methanol and 15-percent gasoline) and that the M85 is sold at the pump on an energy-equivalent basis with gasoline. Differences in transportation and distribution and taxes are taken into account in computing the value of methanol.

Table II-12 shows the imputed methanol value, given the projection of national average gasoline prices contained in the EIA *Annual Energy Outlook 1990*. The projected plantgate value of methanol, which reaches \$0.484 per gallon in 2010, is well below the cost of making it in remote U.S. locations (\$0.71 to \$2.59 per gallon). The primary reason the methanol is uneconomic is that the economies of scale make methanol from small plants sized to the fields very expensive.

This conclusion also is indicated by Table II-13 which, on the left hand side, shows the natural

Table II-8 — Gas Well Cash-Flow in Rocky Mountain Region Completing Existing Well: 500 Mcfd Case

Cost and Financial Assumptions						Tax Scenario					
Region #	=	8	Sev & Ad Val Taxes	=	10.1%	Write Off Schedules					
Drilling Depth	=	10,000	Royalty	=	12.5%	Deprec.	Intang.			Tax	= 37.3%
Drilling Interval	=	6	After-Tax, Real ROR	=	10.0%	0.14	0.700			ITC	= 0.0%
\$/FT Succ Well	=	77.0	Inflation	=	4.0%	0.25	0.060			INTG %	= 70.0%
\$/FT Dry Hole	=	36.3				0.17	0.060				
\$/Succ Well	=	192,500	Success Rate	=	76.0%	0.13	0.060				
\$/Dry Hole	=	0	MMcf/Well	=	1,559	0.11	0.060				
Stimul \$/Well	=	63,250	Btu/cf Dry Gas	=	1,130	0.10	0.060				
Equip/W	=	37,500	Condns (Bbl/MMcf)	=	7.0	0.10	0.000				
O+M/Year	=	26,500									
G&G/Well	=	0	Takes	=	0.900						
Lease/Well	=	0									
Overhead, G&A%	=	16.0%									
		1988\$	1990\$								
\$/Mcf Raw Gas	=	\$1.18	\$1.29								
\$/MMBtu Gas & Condns	=	\$1.02	\$1.11								
		Deprec.	Intang.	Deplet.	Expen.*	Total					
		95,250	198,000	0	46,920	340,170					
Year	GNP Deflator			After-Tax Annual			Gas Prod. (MMcf/Y)	Gas Value \$/Mcf	Net Rev A.T.	Net A.T. Cash-flow	Gas Prod Mcfd
1	1.000	(90,276)	(146,302)	0	(46,034)	(282,613)	60.8	1.18	34,765	(247,848)	167
2	1.040	8,540	4,261	0	(16,616)	(3,814)	121.6	1.18	69,529	65,715	333
3	1.082	5,584	4,097	0	(16,616)	(6,934)	121.6	1.18	69,529	62,595	333
4	1.125	4,106	3,939	0	(16,616)	(8,570)	118.7	1.18	67,844	59,273	325
5	1.170	3,341	3,788	0	(16,616)	(9,487)	94.0	1.18	53,753	44,266	258
6	1.217	2,920	3,642	0	(16,616)	(10,053)	78.5	1.18	44,867	34,814	215
7	1.265	2,808	0	0	(16,616)	(13,808)	67.7	1.18	38,681	24,874	185
8	1.316	0	0	0	(16,616)	(16,616)	59.6	1.18	34,097	17,481	163
9	1.369	0	0	0	(16,616)	(16,616)	53.4	1.18	30,548	13,932	146
10	1.423	0	0	0	(16,616)	(16,616)	48.5	1.18	27,711	11,096	133
11	1.480	0	0	0	(16,616)	(16,616)	44.4	1.18	25,388	8,772	122
12	1.539	0	0	0	(16,616)	(16,616)	41.0	1.18	23,446	6,830	112
13	1.601	0	0	0	0	0	0.0	1.18	0	0	0
14	1.665	0	0	0	0	0	0.0	1.18	0	0	0
15	1.732	0	0	0	0	0	0.0	1.18	0	0	0
16	1.801	0	0	0	0	0	0.0	1.18	0	0	0
17	1.873	0	0	0	0	0	0.0	1.18	0	0	0
18	1.948	0	0	0	0	0	0.0	1.18	0	0	0
19	2.026	0	0	0	0	0	0.0	1.18	0	0	0
20	2.107	0	0	0	0	0	0.0	1.18	0	0	0
					SUM	(418,357)	910		520,157	101,800	
					NPV	(322,109)	563		322,109	(0)	

Table II-9 — Gas Well Cash-Flow in Rocky Mountain Region Drilling New Well: 500 Mcfd Case

Cost and Financial Assumptions						Tax Scenario					
Region # = 8						<u>Write Off Schedules</u>					
Drilling Depth = 10,000		Sev & Ad Val Taxes = 10.1%				Deprec.	Intang.	Tax = 37.3%			
Drilling Interval = 6		Royalty = 12.5%				0.14	0.700	ITC = 0.0%			
\$/Ft Succ Well = 77.0		After-Tax, Real ROR = 10.0%				0.25	0.060				
\$/Ft Dry Hole = 36.3		Inflation = 4.0%				0.17	0.060	INTG % = 70.0%			
\$/Succ Well = 770,000						0.13	0.060				
\$/Dry Hole = 363,283		Success Rate = 76.0%				0.11	0.060				
Stimul \$/Well = 63,250		MMcf/Well = 1,559				0.10	0.060				
Equip/W = 37,500		Btu/cf Dry Gas = 1,130				0.10	0.000				
O+M/Year = 26,500		Condnste (Bbl/MMcf) = 7.0			Takes = 0.900						
G&G/Well = 25,000											
Lease/Well = 50,000											
Overhead, G&A% = 16.0%											
		<u>1988\$</u>	<u>1990\$</u>								
\$/Mcf Raw Gas =	\$3.28	\$3.58									
\$/MMBtu Gas & Condnste =	\$2.82	\$3.08									
	Deprec.	Intang.	Deplet.	Expen.*	Total						
	268,500	602,250	98,684	288,186	1,257,620						
Year	GNP Deflator		After-Tax Annual			Gas Prod. (MMcf/Y)	Gas Value \$/Mcf	Net Rev. A.T.	Net A.T. Cash-flow	Gas Prod. Mcfd	
1	1.000	(254,479)	(445,003)	(97,249)	(197,308)	(994,038)	60.8	3.28	96,662	(897,376)	167
2	1.040	24,075	12,960	2,761	(16,616)	23,180	21.6	3.28	193,325	216,504	333
3	1.082	15,741	12,461	2,655	(16,616)	14,242	21.6	3.28	193,325	207,566	333
4	1.125	11,574	11,982	2,491	(16,616)	9,432	118.7	3.28	188,638	198,070	325
5	1.170	9,417	11,521	1,897	(16,616)	6,220	94.0	3.28	149,459	155,679	258
6	1.217	8,232	11,078	1,523	(16,616)	4,217	78.5	3.28	124,753	128,970	215
7	1.265	7,915	0	1,262	(16,616)	(7,438)	67.7	3.28	107,553	100,114	185
8	1.316	0	0	1,070	(16,616)	(15,546)	59.6	3.28	94,805	79,259	163
9	1.369	0	0	922	(16,616)	(15,694)	53.4	3.28	84,938	69,244	146
10	1.423	0	0	804	(16,616)	(15,812)	48.5	3.28	77,051	61,240	133
11	1.480	0	0	708	(16,616)	(15,907)	44.4	3.28	70,590	54,683	122
12	1.539	0	0	629	(16,616)	(15,987)	41.0	3.28	65,191	49,204	112
13	1.601	0	0	0	0	0	0.0	3.28	0	0	0
14	1.665	0	0	0	0	0	0.0	3.28	0	0	0
15	1.732	0	0	0	0	0	0.0	3.28	0	0	0
16	1.801	0	0	0	0	0	0.0	3.28	0	0	0
17	1.873	0	0	0	0	0	0.0	3.28	0	0	0
18	1.948	0	0	0	0	0	0.0	3.28	0	0	0
19	2.026	0	0	0	0	0	0.0	3.28	0	0	0
20	2.107	0	0	0	0	0	0.0	3.28	0	0	0
					SUM	(1,023,120)	910		1,446,289	423,158	
					NPV	(895,619)	563		895,619	(0)	

Table II-10 — Methanol Conversion Scenarios for Discovered Remote Rocky Mountain Gas Fields

Scenario	Initial per Well Production (Mcf/d)	Wells per Field	Wellhead Gas Cost (1990\$/MMBtu)*	Field Gathering		Total Gas Cost as Methanol Feedstock (1990\$/MMBtu)	Methanol Conversion Plant			Total Methanol Cost (1990\$/gal)	
				Miles of Line	Total Cost (1990\$)		Unit Cost (1990\$/MMBtu)	Plant Capacity**			Costs Exc. Feedstock*** (1990\$/gal)
								STPD	(MMcf/d)		
1	500	1	1.52 - 4.14	0.1	5,280	0.02	1.54 - 4.16	4.9	0.17	2.09	2.28 - 2.59
2	500	4	2.10 - 3.08	4.0	211,200	0.13	2.22 - 3.21	19.5	0.67	1.09	1.35 - 1.47
3	500	8	2.34 - 3.08	9.5	501,600	0.15	2.49 - 3.23	39.0	1.33	0.78	1.08 - 1.17
4	750	1	1.02 - 2.76	0.1	5,280	0.01	1.03 - 2.77	7.3	0.25	1.73	1.85 - 2.06
5	750	4	1.40 - 2.06	4.0	211,200	0.08	1.48 - 2.14	29.2	1.00	0.90	1.08 - 1.16
6	750	8	1.57 - 2.06	9.5	501,600	0.10	1.66 - 2.16	58.5	2.00	0.65	0.85 - 0.91
7	1,000	1	0.76 - 2.07	0.1	5,280	0.01	0.77 - 2.08	9.7	0.33	1.51	1.60 - 1.76
8	1,000	4	1.05 - 1.54	4.0	211,200	0.06	1.11 - 1.60	39.0	1.33	0.78	0.92 - 0.98
9	1,000	8	1.17 - 1.54	9.5	501,600	0.07	1.24 - 1.61	78.0	2.67	0.57	0.71 - 0.76

* All cases assume wells drilled to 10,000 feet. Lower end of costs assumes some wells have been drilled but not completed, while upper end of costs assumes all new wells must be drilled. Assumes restricted production pattern over an average of 12 years per well for four-well and eight-well fields. Cost for one-well fields based on very restricted production pattern.

** Plant capacity sized to field assuming nearly constant production level over 15 years.

***Nonfeedstock methanol cost computed from equation: \$/gal. = $4.42 \times (\text{STPD})^{-0.472}$. Natural gas requirements are 0.1198 MMBtu per gallon.

Table II-11 — U.S. Plantgate Methanol Value Given Competing Gasoline Price
(1989 dollars per gallon)

Gasoline		M85	
Gasoline Pump Price	1.060	Required M85 Pump Price (@ 1.74:1)	0.609
Federal Fuel Tax	0.090	Federal Fuel Tax	0.045
State Fuel Tax	0.090	State Fuel Tax	0.045
Sales Tax @ 5%	0.042	Sales Tax @ 5%	0.025
Total Taxes	0.222	Total Taxes	0.115
Pump Price Less Taxes	0.838	Pump Price Less Taxes	0.494
Outlet Markup	0.089	Outlet Markup	0.115
Trucking to Station	0.013	Trucking to Station	0.013
Terminal	0.016	Terminal	0.021
Total Distribution	0.118	Total Distribution	0.149
Wholesale Gasoline Price	0.721	Wholesale M85 Price	0.346
		Wholesale Gasoline Price	0.721
		Wholesale Methanol Price	0.279
		Trucking to Blender (100 miles)	0.030
		Plantgate Methanol Price	0.249

Source: Energy and Environmental Analysis report to DOE, "Capital and Operating Costs of a Fuel Methanol Distribution System—1988 Update," October 1988.

gas wellhead netback value, assuming that the gas is used to make methanol. The netback values are computed using various size methanol plants, ranging from 50 STPD (1.8 MMcf of gas) to 2,500 STPD (91.2 MMcf). The 2,500-STPD plant is assumed to be of conventional (not modular) construction and to offer more efficient conversion (0.098 versus 0.1198 MMBtu per gallon). The netback value is negative for all size plants through the year 1994. This means that even if the cost of the natural gas were zero, the methanol plants would be uneconomic. For the two smallest plants, those most typical for small remote fields, the netback value remains negative even to the year 2008.

The projected Rocky Mountain natural gas wellhead price for pipeline sales as derived from the EIA *Annual Energy Outlook 1990* also is shown in Table II-13 and is derived on Table II-14. EIA projects only a national average wellhead price for gas. This report assumes that the Rocky Mountain price would be 20 cents per MMBtu below the national average price, which is consistent with recent

Rocky Mountain spot gas prices relative to the rest of the country.

The Rocky Mountain wellhead price for gas is shown in column "h" of Table II-13 and is compared to the value of converting natural gas to methanol using either a 200-STPD plant (the smallest economically practical) or a 2,500-STPD plant. In the year 2000 for instance, the methanol conversion option has the value of \$0.36 per MMBtu for a 200-STPD plant and \$1.08 for a 2,500-STPD plant. (The use of these size plants, of course, would require that several remote fields be aggregated.) In comparison, pipeline sales have a value of \$3.17 per MMBtu, assuming that the gas deposits were near a pipeline. The difference against the 200-STPD plant is \$2.81 per MMBtu (3.17 minus 0.36). This \$2.81 could pay for up to 75 miles of gathering line if the initial production from the field being transported were 2 MMcf. If the initial volumes were 4 MMcf, up to 150 miles of gathering line could be justified by the difference in the value of the gas. This means that even if the producer could take advantage of some economies of scale by

**Table II-12 — Energy Information Administration Retail Gasoline Price Forecast
and Equivalent Methanol Plantgate Prices**

Year	1989 Dollars per Gallon		1990 Dollars per Gallon	
	U.S. Average Retail Gasoline	Equivalent Methanol Plantgate	U.S. Average Retail Gasoline	Equivalent Methanol Plantgate
1989	1.06	0.249	1.11	0.261
1990	1.05	0.245	1.10	0.256
1991	1.06	0.251	1.11	0.262
1992	1.08	0.258	1.13	0.269
1993	1.09	0.264	1.14	0.276
1994	1.11	0.271	1.16	0.283
1995	1.12	0.278	1.17	0.290
1996	1.16	0.295	1.21	0.308
1997	1.19	0.312	1.25	0.326
1998	1.23	0.330	1.29	0.345
1999	1.27	0.349	1.33	0.365
2000	1.31	0.368	1.37	0.385
2001	1.33	0.378	1.39	0.396
2002	1.35	0.389	1.41	0.406
2003	1.37	0.399	1.44	0.417
2004	1.40	0.410	1.46	0.428
2005	1.42	0.421	1.48	0.440
2006	1.44	0.429	1.50	0.448
2007	1.46	0.438	1.52	0.457
2008	1.47	0.446	1.54	0.466
2009	1.49	0.455	1.56	0.475
2010	1.51	0.464	1.58	0.484
Growth Rate (Percent)				
1990-1995	1.30	2.59	1.30	2.59
1995-2000	3.18	5.79	3.18	5.79
2000-2005	1.63	2.69	1.63	2.69
2005-2010	1.24	1.96	1.24	1.96

Source: *Annual Energy Outlook 1990*, DOE/EIA, January 1990.

aggregating several remote fields into the 6.84 MMcf/d needed by the 200-STPD plant, the fields would each have to be more than 75 miles away from pipelines and would have to be developed for under \$0.36 per MMBtu for methanol conversion to be undertaken. Because EIA forecasts natural gas prices to rise more quickly than gasoline, the advantage of the pipeline sales grows so that by 2010 a small remote field would have to be a minimum of 119 miles from a pipeline for methanol to win out over pipeline sales.

CASE STUDY OF THE DEVELOPMENT OF REMOTE GAS RESOURCES: SAGINAW BAY PIPELINE, MICHIGAN BASIN

Introduction

Over the past few years, a major new gas play has developed in the eastern Michigan Basin. Because of the location of the fields and the volume of reserves discovered, a new pipeline is required. The proposed line is called the Saginaw Bay Pipeline and is scheduled for construction later this year. This case study is presented as an example of the nature and

Table II-13 — Comparison of Value of Remote Gas as Methanol Feedstock Versus Pipeline Sales

Year	Methanol Plantgate Value from EIA (1990\$/gal)	Value of Natural Gas as Feedstock for Methanol Conversion for Various Plant Sizes (1990\$/MMBtu)					Pipeline Sales Option				
		50 STPD (1.71 MMcf/d)	100 STPD (3.42 MMcf/d)	200 STPD (6.84 MMcf/d)	300 STPD (10.3 MMcf/d)	2,500 STPD (82.8 MMcf/d)	Rockies Natural Gas Wellhead Price from EIA (1990\$/MMBtu)	Versus 200-STPD Plant		Versus 2,500-STPD Plant	
		[c]	[d]	[e]	[f]	[g]		Difference in Value of Gas (1990\$/MMBtu)	Miles of Gathering Line That Would Be Economic for 2 MMcf/d*	Difference in Value of Gas (\$/MMBtu)	Miles of Gathering Line That Would Be Economic for 2 MMcf/d*
1989	0.261	(3.58)	(1.61)	(0.68)	(0.20)	(0.19)	1.65	N/A	N/A	N/A	N/A
1990	0.256	(3.63)	(1.65)	(0.72)	(0.25)	(0.24)	1.68	N/A	N/A	N/A	N/A
1991	0.262	(3.57)	(1.59)	(0.66)	(0.19)	(0.17)	1.77	N/A	N/A	N/A	N/A
1992	0.269	(3.51)	(1.53)	(0.61)	(0.13)	(0.10)	1.85	N/A	N/A	N/A	N/A
1993	0.276	(3.45)	(1.48)	(0.55)	(0.07)	(0.03)	1.95	N/A	N/A	N/A	N/A
1994	0.283	(3.39)	(1.42)	(0.49)	(0.01)	0.04	2.04	N/A	N/A	2.00	53
1995	0.290	(3.34)	(1.36)	(0.43)	0.05	0.12	2.14	N/A	N/A	2.03	54
1996	0.308	(3.19)	(1.21)	(0.28)	0.19	0.30	2.32	N/A	N/A	2.02	54
1997	0.326	(3.03)	(1.06)	(0.13)	0.35	0.48	2.51	N/A	N/A	2.02	54
1998	0.345	(2.88)	(0.90)	0.03	0.50	0.68	2.71	2.68	71	2.03	54
1999	0.365	(2.71)	(0.74)	0.19	0.67	0.88	2.93	2.74	73	2.06	55
2000	0.385	(2.55)	(0.57)	0.36	0.83	1.08	3.17	2.81	75	2.09	56
2001	0.396	(2.46)	(0.48)	0.45	0.92	1.19	3.38	2.93	78	2.19	58
2002	0.406	(2.37)	(0.39)	0.54	1.01	1.30	3.60	3.06	81	2.30	61
2003	0.417	(2.28)	(0.30)	0.63	1.10	1.41	3.83	3.20	85	2.42	64
2004	0.428	(2.18)	(0.21)	0.72	1.20	1.52	4.08	3.36	89	2.56	68
2005	0.440	(2.09)	(0.11)	0.81	1.29	1.64	4.35	3.53	94	2.71	72
2006	0.448	(2.02)	(0.04)	0.89	1.36	1.73	4.59	3.70	98	2.86	76
2007	0.457	(1.94)	0.04	0.96	1.44	1.82	4.84	3.88	103	3.02	80
2008	0.466	(1.87)	0.11	1.04	1.51	1.91	5.10	4.07	108	3.19	85
2009	0.475	(1.79)	0.19	1.11	1.59	2.00	5.38	4.27	114	3.38	90
2010	0.484	(1.72)	0.26	1.19	1.66	2.10	5.67	4.49	119	3.58	95
Nongas meth. \$/gal:		0.690	0.453	0.342	0.285	0.279					
MMBtu nat. gas/gal:		0.1198	0.1198	0.1198	0.1198	0.098					

*Based on 4-inch line at \$14 per foot which translates into 3.8 cents per MMBtu per mile. Multiply by 2 to get miles for 4-MMcf/d peak production. This represents distance between gas field and pipeline beyond which methanol conversion is preferred to pipeline sales because of cost of connecting to pipeline.

Table II-14 — Energy Information Administration Natural Gas Price Forecast

Year	1989 Dollars per MMBtu		1990 Dollars per MMBtu	
	U.S. Average Natural Gas Wellhead Price	Rockies Natural Gas Wellhead Price	U.S. Average Natural Gas Wellhead Price	Rockies Natural Gas Wellhead Price
1989	1.78	1.58	1.86	1.65
1990	1.81	1.61	1.89	1.68
1991	1.89	1.69	1.98	1.77
1992	1.97	1.77	2.06	1.85
1993	2.06	1.86	2.16	1.95
1994	2.15	1.95	2.25	2.04
1995	2.25	2.05	2.35	2.14
1996	2.42	2.22	2.53	2.32
1997	2.60	2.40	2.72	2.51
1998	2.80	2.60	2.92	2.71
1999	3.00	2.80	3.14	2.93
2000	3.23	3.03	3.38	3.17
2001	3.43	3.23	3.58	3.38
2002	3.64	3.44	3.81	3.60
2003	3.87	3.67	4.04	3.83
2004	4.11	3.91	4.29	4.08
2005	4.36	4.16	4.56	4.35
2006	4.59	4.39	4.80	4.59
2007	4.83	4.63	5.05	4.84
2008	5.08	4.88	5.31	5.10
2009	5.35	5.15	5.59	5.38
2010	5.63	5.43	5.88	5.67
Growth Rate (Percent)				
1990–1995	4.45	4.95	4.45	4.95
1995–2000	7.50	8.13	7.50	8.13
2000–2005	6.18	6.54	6.18	6.54
2005–2010	5.25	5.47	5.25	5.47

Source: Average from *Annual Energy Outlook 1990*, DOE/EIA, January 1990. Rockies price assumed to be 20 cents below national average.

timing of remote gas field development where a major gas play requires the construction of a new pipeline system.

Pipeline and Resource Description

Figure II-2 shows the location of the proposed pipeline. It will consist of 126 miles of 10 3/4- and 16-inch pipe and is expected to cost \$39.5 million. The pipeline will move gas from new discoveries in the Saginaw Bay area to existing gas-processing facilities in Kalkaska County. The processed gas will be transported to market through existing lines.

The interval between initial play discoveries to expected completion of the pipeline is approximately 6 years. Figure II-3 shows the chronology of developing the new supply area and getting the pipeline approved. The initial discoveries were made in 1984 and 1985. As the graph shows, new gas wells were completed each year, resulting in the 1990 total of 44. Most of the current completions were made in 1987 and 1988.

Figure II-3 also shows the steps involved in getting the pipeline built: an evaluation of reservoirs and marketability by the pipeline company, the application to build the pipeline,

review by the public service commission, approval, and construction.

Table II-15 summarizes the characteristics of the new gas supply area and the proposed pipeline. Published estimates indicate that the existing wells have proven between 500 and 536 bcf of new reserves. Due to the rapid expansion and regional nature of the play, eventual ultimate recovery could be in the range of one to several trillion cubic feet.

Economics of Methanol Versus Pipeline Sales

Table II-16 shows the cost of developing small Michigan Basin Prairie Du Chien formation fields for methanol conversion. It is similar to that shown earlier for the Green River Basin, except that cost and engineering parameters appropriate to the Michigan Basin were used. Because of the higher productivity of the Michigan wells (3,000 Mcfd versus 500-1,000

Mcfd in the Rockies), larger methanol plants can be used, leading to lower, more competitive methanol costs. The eight-well field could be used to make methanol costing between \$0.42 and \$0.46 per gallon, which is in line with the plantgate methanol prices expected after 2004.

The competitiveness of the methanol option versus pipeline sales is shown on Table II-17. The value of the natural gas used to make methanol is shown in columns "c" to "g" for plants ranging from 50 to 2,500 STPD. These netback values are identical to those shown earlier for the Rocky Mountain case, since the methanol plant costs and methanol prices are assumed to be the same for the two locations. The natural gas wellhead values are assumed to be higher in Michigan by 40 cents per MMBtu versus the Rockies because gas in Michigan commands a higher value because of its proximity to major gas consumption

Figure II-2 — Map Showing Proposed Route of Saginaw Bay Pipeline

Figure II-3 — Saginaw Bay Pipeline Chronology

A Initial discoveries are made by Amoco, Shell, and Sun. B MichCon completes several months of study to evaluate best way to get gas to market. C Saginaw Bay Pipeline files an application to build pipeline. D Michigan Public Service Commission begins formal hearings on several pipeline proposals.	E Saginaw Bay Pipeline is selected as the preferred option. F Saginaw Bay Pipeline announces an agreement to provide 20 MMcfpd to the Midland Cogeneration Venture. G Final approval for pipeline construction to begin. H Pipeline expected to be completed.

centers and lower transportation costs. Gathering lines to the Michigan pipeline initially are assumed to carry 4 MMcfpd versus 2 MMcfpd in the Rockies, because of the higher typical productivities assumed for the Michigan wells.

The conclusion indicated by Table II-17 is that gas fields in Michigan would have to be very remote from existing pipelines to justify conversion to methanol. Compared against a 200-STPD plant, building up to 120 miles of line for pipeline sales would be economic in the year 2000 and up to 182 miles in 2010.

Table II-15 — Saginaw Bay Pipeline Project, Michigan Basin

Gas Supply Data	
Current completions in supply area	44
Total number of fields involved	14
Current proved reserves (bcf)	approx. 500
Typical ultimate recovery per completion (bcf)	8
Average completion depth (ft)	10–11,000
Gas contaminants	3–5% N ₂
Range of well test rates (MMcfpd)	1–6
Condensate ratio (bbls/MMcf)	30–50
Primary discovery type	Deeper pool
Pipeline Data	
Length of main pipeline (mi)	126
Diameter	10 ¾ and 16 inch
Estimated cost, main pipeline	\$39.5 million
Estimated gathering line length (mi)	100

Table II-16 — Methanol Conversion Scenarios for Discovered Remote Michigan Gas Fields

Scenario	Initial per Well Production (Mcf/d)	Wells per Field	Wellhead Gas Cost (1990\$/MMBtu)*	Field Gathering		Total Gas Cost as Methanol Feedstock (1990\$/MMBtu)	Methanol Conversion Plant			Total Methanol Cost (1990\$/gal)	
				Miles of Line	Total Cost (1990\$)		Unit Cost (1990\$/MMBtu)	Plant Capacity** STPD	(MMcfd)		Costs Exc. Feedstock*** (1990\$/gal)
1	3,000	1	0.22 - 1.37	0.1	5,280	0.00	0.22 - 1.37	29.2	1.00	0.90	0.93 - 1.06
2	3,000	4	0.59 - 1.01	4.0	211,200	0.02	0.61 - 1.03	117.0	4.00	0.47	0.54 - 0.59
3	3,000	8	0.69 - 1.01	9.5	501,600	0.02	0.72 - 1.03	233.9	8.00	0.34	0.42 - 0.46

* All cases assume wells drilled to 11,000 feet. Lower end of costs assumes some wells have been drilled but not completed, while upper end of costs assumes all new wells must be drilled. Assumes restricted production pattern over an average of 12 years per well for four-well and eight-well fields. Cost for one-well fields based on very restricted production pattern.

** Plant capacity sized to field assuming nearly constant production level over 15 years.

***Nonfeedstock methanol cost computed from equation: \$/gal. = $4.42 \times (\text{STPD})^{-0.472}$. Natural gas requirements are 0.1198 MMBtu per gallon.

Table II-17 — Comparison of Value of Remote Michigan Basin Gas as Methanol Feedstock Versus Pipeline Sales

Year	Methanol Plantgate Value from EIA (1990\$/gal)	Value of Natural Gas as Feedstock for Methanol Conversion for Various Plant Sizes (1990\$/MMBtu)					Pipeline Sales Option				
							Michigan Natural Gas Wellhead Price from EIA* (1990\$/MMBtu)	Versus 200 STPD Plant		Versus 2,500 STPD Plant	
		50 STPD (1.71 MMcf/d) [c]	100 STPD (3.42 MMcf/d) [d]	200 STPD (6.84 MMcf/d) [e]	300 STPD (10.3 MMcf/d) [f]	2,500 STPD (82.8 MMcf/d) [g]		Difference in Value of Gas (1990\$/MMBtu) [h-e]	Miles of Gathering Line That Would Be Economic for 4 MMcf/d**	Difference in Value of Gas (\$/MMBtu) [h-g]	Miles of Gathering Line That Would Be Economic for 4 MMcf/d**
1989	0.261	(3.58)	(1.61)	(0.68)	(0.20)	(0.19)	2.05	N/A	N/A	N/A	N/A
1990	0.256	(3.63)	(1.65)	(0.72)	(0.25)	(0.24)	2.08	N/A	N/A	N/A	N/A
1991	0.262	(3.57)	(1.59)	(0.66)	(0.19)	(0.17)	2.17	N/A	N/A	N/A	N/A
1992	0.269	(3.51)	(1.53)	(0.61)	(0.13)	(0.10)	2.25	N/A	N/A	N/A	N/A
1993	0.276	(3.45)	(1.48)	(0.55)	(0.07)	(0.03)	2.35	N/A	N/A	N/A	N/A
1994	0.283	(3.39)	(1.42)	(0.49)	(0.01)	0.04	2.44	N/A	N/A	2.40	89
1995	0.290	(3.34)	(1.36)	(0.43)	0.05	0.12	2.54	N/A	N/A	2.43	90
1996	0.308	(3.19)	(1.21)	(0.28)	0.19	0.30	2.72	N/A	N/A	2.42	90
1997	0.326	(3.03)	(1.06)	(0.13)	0.35	0.48	2.91	N/A	N/A	2.42	90
1998	0.345	(2.88)	(0.90)	0.03	0.50	0.68	3.11	3.08	115	2.43	91
1999	0.365	(2.71)	(0.74)	0.19	0.67	0.88	3.33	3.14	117	2.46	92
2000	0.385	(2.55)	(0.57)	0.36	0.83	1.08	3.57	3.21	120	2.49	93
2001	0.396	(2.46)	(0.48)	0.45	0.92	1.19	3.78	3.33	124	2.59	96
2002	0.406	(2.37)	(0.39)	0.54	1.01	1.30	4.00	3.46	129	2.70	101
2003	0.417	(2.28)	(0.30)	0.63	1.10	1.41	4.23	3.60	134	2.82	105
2004	0.428	(2.18)	(0.21)	0.72	1.20	1.52	4.48	3.76	140	2.96	110
2005	0.440	(2.09)	(0.11)	0.81	1.29	1.64	4.75	3.93	147	3.11	116
2006	0.448	(2.02)	(0.04)	0.89	1.36	1.73	4.99	4.10	153	3.26	121
2007	0.457	(1.94)	0.04	0.96	1.44	1.82	5.24	4.28	159	3.42	127
2008	0.466	(1.87)	0.11	1.04	1.51	1.91	5.50	4.47	166	3.59	134
2009	0.475	(1.79)	0.19	1.11	1.59	2.00	5.78	4.67	174	3.78	141
2010	0.484	(1.72)	0.26	1.19	1.66	2.10	6.07	4.89	182	3.98	148
Nongas meth. \$/gal:		0.690	0.453	0.342	0.285	0.279					
MMBtu nat. gas/gal:		0.1198	0.1198	0.1198	0.1198	0.098					

* Michigan Basin gas prices assumed to be 20 cents per MMBtu above national average.

**Based on 6-inch line at \$20 per foot which translates into 2.7 cents per MMBtu per mile. This represents distance between gas field and pipeline beyond which methanol conversion is preferred to pipeline sales because of cost of connecting to pipeline.

III. DISTRIBUTION AND CHARACTERISTICS OF UNUTILIZED, LOW-QUALITY GAS

INTRODUCTION

Most of the gas-producing basins in the United States contain some quantities of acid or low-Btu gas. Most of these plays or areas are well known to the industry, and within their boundaries gas composition is a definite factor in the economics of both exploration and development. In general, such occurrences are restricted to certain areas or formations within a basin. In plays that have been heavily explored, the areal extent of the low-quality gas occurrence usually is known. In more frontier areas, the distribution may be poorly known.

Because gas composition is a major factor in determining the economic viability of a deposit, it is inevitable that a certain number of gas "discoveries" are never produced because of low-quality gas. Such gas represents an unutilized, discovered resource that may become economic to develop through improved gas-processing technologies or other means such as methanol conversion. While it is often difficult to assess the gas reserves associated with such "discovered, nonproducing" gas, it is possible to estimate well characteristics and create realistic scenarios for economic analysis.

For this study, it is important to demonstrate the distribution and typical characteristics of low-quality gas production and the economics of producing and processing such gas. An evaluation of the gas composition and economics of discovered and undiscovered gas resources in the United States was recently completed by Energy and Environmental Analysis, Inc. under contract to the Gas Research Institute (GRI).^{*} This data base is the most comprehensive source of information

available to evaluate the distribution and characteristics of low-quality gas.

ORIGIN OF LOW-QUALITY GAS

Natural gas is a mixture of hydrocarbon and nonhydrocarbon components and exhibits compositional variability among geological provinces and within individual basins. The most common nonhydrocarbons in natural gases are carbon dioxide (CO₂), nitrogen (N₂), and hydrogen sulfide (H₂S). Other nonhydrocarbons that may be present are oxygen, helium, hydrogen, argon, and several sulfur compounds other than H₂S. Other possible contaminants include mercury, arsenic, and ammonia.

Variability in the composition of natural gas results primarily from the kerogen type and lithology of source rocks and the burial and temperature history of the basin. Both geochemical and geological factors are important. Because different components of natural gas are generated with increasing depth and temperature, a compositional zonation of natural gas commonly is present within a basin. This zonation may be characterized by a shallow zone of biogenic methane and nitrogen; an intermediate zone with methane, heavier hydrocarbon gases, and carbon dioxide; and a deep zone of methane and hydrogen sulfide.

Carbon Dioxide

Carbon dioxide is formed by a variety of geological processes. Probably the most important modes of origin are thermogenic alteration of source rock materials (as they are buried to progressively greater depths) and thermal metamorphism of carbonate rocks by igneous intrusives.

There is strong geological evidence that thermal metamorphism of carbonate rocks is responsible for most of the high-CO₂ and pure

^{*}Hugman, R. H., E. H. Vidas, and P. S. Springer, 1990, "Chemical Composition of Discovered and Undiscovered Natural Gas in the Lower-48 United States," report prepared for Gas Research Institute by Energy and Environmental Analysis, Inc., Arlington, VA. GRI Report No. 90/0248.

CO₂ accumulations. Igneous intrusives are found in association with carbonate rocks in most of the areas where such gas is found. In general, the composition of such gases is very high in CO₂, with minor amounts of hydrocarbons. The high-CO₂ content appears to result, in some cases, from multistage generation and migration.

Natural gas with moderate concentrations of carbon dioxide (3- to 10-percent range) may result from thermogenic alteration of coaly source materials. Examples include the Fruitland coalbed methane of the San Juan Basin and some Cretaceous Mesaverde gas in the Green River and Piceance Basins in Wyoming and Colorado.

Nitrogen

Nitrogen appears to be derived primarily from either the degassing of basement rocks or the maturation of coaly source materials. A strong association between the occurrence of nitrogen and granitic basement uplifts has been observed in the midcontinent area. Nitrogen in this area occurs in association with helium, which is basement-derived.

Nitrogen also is generated thermogenically through the burial and maturation of coaly sediments or source materials. High-nitrogen gases often are present in continental redbed sequences. The Permian Chase Group of the Hugoton Field of southwest Kansas contains about 15 percent nitrogen. The carbonate reservoirs are downdip from a redbed sequence to the west. High-nitrogen gases also are found in the North Sea, where they are produced from redbeds beneath a thick salt section.

Hydrogen Sulfide

Hydrogen sulfide is generated through biogenic (bacterial) processes and through the thermal alteration of source beds. While large quantities of biogenic H₂S are generated, little of this gas is preserved in the subsurface because of its high solubility in water at low temperatures and pressures. Therefore, most preserved H₂S is generated at depth through the thermal alteration of source beds.

Hydrogen sulfide generally is associated with carbonate (limestone and dolomite) reservoirs

in the deep portion of a basin. There are several geochemical reasons for this association, involving both a greater generation of H₂S in carbonates and a lesser tendency to cause the conversion of H₂S to other sulfur compounds. However, sandstone reservoirs may also contain H₂S. A prominent example of this is the Jurassic Norphlet aeolian sandstone play in Mobile Bay, Alabama.

In the United States, nonassociated hydrogen sulfide is found in Paleozoic carbonates in the Rockies, midcontinent, Permian Basin, and Michigan and Illinois Basins, and in Cretaceous and Jurassic carbonates and sandstones of the Gulf Coast and East Texas. It often occurs in association with CO₂ in the deeper portions of a basin. The concentration of H₂S may range from a few parts per million to 30 percent or more.

DISTRIBUTION AND CHARACTERISTICS OF LOW-QUALITY GASES IN THE UNITED STATES

Figure III-1 shows the distribution of carbon dioxide, nitrogen, and hydrogen sulfide in U.S. natural gas deposits. In the Rocky Mountain States, CO₂ is the principal contaminant. It occurs as almost pure CO₂ and also as a contaminant in flammable gases. Coalbed methane is a large potential source of low-quality gas in the Rockies. The San Juan Basin Fruitland Coal contains gas with the following average composition:

Methane	94%
C ₂ through C ₅	0.4%
Carbon dioxide	5% (up to 10%)
Nitrogen	0.2%
Hydrogen sulfide	0%
Heating value	972 Btu/cf

Other Rocky Mountain plays with low-quality gas include the Wyoming-Utah Overthrust Belt (H₂S, CO₂), the Morrow in southeastern Colorado (N₂), and several formations along the Douglas Creek Arch in northwestern Colorado (N₂).

**Figure III-1— Distribution of Carbon Dioxide, Nitrogen,
and Hydrogen Sulfide in the United States**

**Major
Carbon Dioxide-Prone
Areas**
(Does not include pure Carbon Dioxide)

**Major
Nitrogen-Prone
Areas**

**Major
Hydrogen Sulfide-Prone
Areas**

The midcontinent area generally is nitrogen-prone. The giant Hugoton Field in southwest Kansas and the Oklahoma and Texas Panhandle is about 15-percent nitrogen. A typical analysis is:

Methane	73.4%
C ₂ through C ₅	11.0%
Carbon dioxide	0.0%
Nitrogen	14.9%
Hydrogen sulfide	0.0%
Helium	0.4%
Heating value	999 Btu/cf

Nitrogen is widely distributed across the older producing basins of Oklahoma and Kansas. It is found in both nonassociated and associated reservoirs, and its distribution appears to be related to the presence of large regional basement uplifts.

The Permian Basin of West Texas is considered primarily an oil and associated gas province, although large amounts of nonassociated gas also occur. A large portion of the gas reserves are contaminated by either CO₂, N₂, or H₂S. One of the most significant formations with low-Btu gas is the Cambro-Ordovician Ellenburger carbonate sequence. Nonassociated fields producing from this formation have CO₂ contents ranging from 2 to 90 percent. Numerous low-Btu fields in this play have been developed and produced. Heating values of these fields are in the range of 500 to 800 Btu per cubic foot.

The Michigan Basin historically has produced a large amount of low-quality, H₂S-contaminated gas. The sour gas is produced from relatively shallow carbonate reservoirs. Concentrations are highly variable but are commonly less than 100 parts per million. Nitrogen also is a common component and may occur in concentrations of 10 to 20 percent.

Another significant area of low-quality gas is the Sacramento Basin in Northern California. Here, numerous fields contain high nitrogen

contents, ranging from 5 to 60 percent. Because nitrogen is the only contaminant, the pipeline companies are able to blend the low-Btu production with higher Btu gas. In this way, some very low quality gas fields have been produced economically. The following is an example of the composition of one of the low-Btu reservoirs:

Methane	70.3%
C ₂ through C ₅	0.6%
Carbon dioxide	Trace
Nitrogen	28.5%
Heating value	749 Btu/cf

MAJOR OCCURRENCES OF DISCOVERED, NONPRODUCING, LOW-QUALITY GAS

The recently completed GRI research project documented the known major occurrences of discovered, nonproducing low-quality gas in the Lower 48. Figure III-2 is an index map showing the location of each deposit. Each of these deposits was evaluated for average gas composition, depth, type of accumulation, expected well recovery, accumulation size (if possible), and wellhead resource cost per Mcf and MMBtu.

Tables III-1 and III-2 summarize the characteristics of these deposits or plays. An estimate of total ultimate recovery was possible for only three of the accumulations. However, these three areas contain a recoverable resource of 135,000 billion cubic feet (bcf) and contain about 10 percent, or 13,500 bcf, of hydrocarbons.

Table III-2 shows the gas composition and heating value of the unutilized or nonproducing portion of each accumulation. The table also shows the wellhead resource costs in 1990 dollars per Mcf and per MMBtu. The wellhead resource cost is the cost of the gas prior to gas processing. The costs of gas processing in dollar per Mcf or MMBtu are added to these costs to obtain the total resource cost delivered to a pipeline.

Figure III-2 — Identified Significant Areas of Discovered, Nonproducing Subquality Gas

FACTORS AFFECTING ECONOMICS OF PRODUCTION AND PROCESSING

Gas composition and heating value are important elements in a decision to complete or abandon a potentially productive gas well. Pipeline-quality gas typically must contain no more than 2 percent CO_2 or 4 parts per million of H_2S . Nitrogen, while noncorrosive, reduces the heating value of the gas. A well containing acid gas (CO_2 or H_2S) must be completed using higher cost, noncorrosive tubing and wellhead equipment. A gas reservoir contaminated only by nitrogen can be produced without the need for special equipment, assuming that the gas can be blended to meet pipeline specifications. However, if blending is not possible, the economics of gas processing must be considered.

If the gas has to be upgraded, gas processing facilities must be built at or near the field. The economics of producing and processing are

dependent upon the wellhead resource costs, the gas composition, deliverability and reserves involved, the type of plant or process, the presence and marketability of coproducts, and the stability of markets for the upgraded gas.

In certain cases, marketable products result from gas processing. These include helium, sulfur, and carbon dioxide. Because of the need for capital-intensive cryogenic processing, helium is produced only in large, specialized plants. Sulfur is produced at dozens of gas plants around the country, with gas throughput volumes ranging from 10 to 250 million cubic feet per day. The H_2S content of such reservoirs typically is in the range of several percent (1 percent equals 10,000 parts per million). For gas streams with CO_2 , special pipelines must be built. The market for CO_2 as a product of gas processing is limited both by demand and by the availability of large, low-cost, naturally occurring pure CO_2 deposits.

**Table III-1 — Summary of Identified Major Occurrences
of Discovered, Uneconomic, or Nonproducing Subquality Gas**

Area	State	Formation	Single-Multiple Reservoir	Depth (ft.)	Areal Extent (sq.mi.)	Range of Discovered Nonproducing Raw Gas (bcf)	Raw Gas Ultimate per Well (bcf)	Hydrocarbons (%)	Contaminants	Comments
Northern Moxa Arch	SW Wyoming	Madison	Single	14–18,000	1,300	128,000	123	7	CO ₂ ,N ₂ ,H ₂ S	Estimates are for undeveloped portion of reservoir only.
Church Buttes Area	SW Wyoming	Madison	Single	18,000	50–100?	4,500–7,700	50–100?	6	CO ₂ ,N ₂ ,H ₂ S	No current production or known development plan.
Hadden Deep Area	Gen. Wyoming	Madison	Single	24,000	31–70	750–1,000	35–50	68	CO ₂ ,H ₂ S	Reservoir to be developed.
Kevin-Sunburst Dome	NW Montana	Duperow	Single	3–5,000	100–1,000?	Possible major accumulation	10?	4–12	CO ₂ ,N ₂	No resource estimates were found. Great uncertainty about extent and nature of accumulation.
Wasatch Plateau	E Utah	(Various)	Multiple	3–5,000	?	No estimate	5?	3–34	CO ₂ ,N ₂	No overall resource estimates found. Appears to be less than a few tcf.
Jackson Dome Area	Mississippi	Smackover, Norphlet	Multiple	14–17,000	?	No estimate	10	10–25	CO ₂ ,H ₂ S	Regional CO ₂ reserves estimated at 2 to 4 tcf. No estimate of discovered, low-Btu resources was found.
Smackover Trend	SW Arkansas	Smackover	Multiple	6–11,000	?	No estimate	1.33	30–60	N ₂ ,H ₂ S	No resource estimates were found.
Sacramento Basin	California	(Various)	Multiple	4–10,000	?	No estimate	1.0–1.5	30–60	N ₂	State of California performed a resource assessment in 1984. They reported only 2 bcf of discovered, nonproducing reserves. This estimate is too low.
Los Animes Arch	Colorado	Morrow, Miss.	Multiple	5,000	?	No estimate	1.25	40–80	N ₂	Some of the low-Btu gas is associated with oil.

**Table III-2 — Typical Composition and Resource Costs
for Discovered Nonproducing Low-Quality Gas Areas**

Area	State	Observed Typical Composition						Wellhead Resource Costs		
		C ₁	C ₂ -C ₆	CO ₂	N ₂	H ₂ S	HE	Heating Value (Btu/cf)	1990 Dollars per Mcf	1990 Dollars per MMBtu
N. Moxa Arch, Madison	Wyoming	7	0.0	83	7	2.0	0.6	180	0.22	1.10
Church Buttes, Madison	Wyoming	6	0.6	87	6	0.1	0.3	110	N/A	N/A
Madden Deep, Madison	Wyoming	68	—	19	—	11.0	—	759	1.31	1.66
Kevin-Sunburst Duperow	Montana	4	1.4	87	8	0.0	0.3	71	0.22	1.87
Wasatch Plateau	Utah	3	0.1	89	7	0.0	—	40	N/A	N/A
Jackson Dome, Smackover	Mississippi	25	—	65	—	10.0	—	300	2.93	7.68
Smackover Trend	Arkansas	55	9.0	6	29	0.6	0.1	789	5.35	6.20
Sacramento Basin	California	35	0.0	0	64	0.0	0.0	365	N/A	N/A
Las Animas Arch, Morrow	Colorado	24	5.0	1	66	0.0	3.5	383	2.98	7.22

ECONOMIC SCENARIOS

Two cases are shown here to illustrate the economics of processing low-Btu gas for pipeline sales and to compare that option with conversion to methanol. The first case assumes a gas that contains 30 percent carbon dioxide and the second case assumes a gas with 30 percent nitrogen.

Economics of High-Carbon-Dioxide Gases

Carbon dioxide most often is removed from natural gas using one of several amine processes in which the gas is mixed with a lean amine solution into which the CO₂ is absorbed. The rich solution then is regenerated by heating to release the CO₂.

Estimated capital and operating costs are shown in Table III-3 for plant capacities of 2 MMcf/d to 100 MMcf/d. These examples are for the 30-percent CO₂ gas, which must be re-

duced to 2-percent CO₂ to meet pipeline specifications. As should be expected, the amine plants show considerable economies of scale. Processing the gas in the 2-MMcf/d plant costs \$1.14 per Mcf of sales gas, while the cost for the 100-MMcf/d plant is \$0.46 per Mcf of sales gas.

Figure III-3 shows these economies of scale graphically. It also shows processing costs for varying amounts of CO₂ in the gas ranging from 10 percent to 60 percent. Costs increase with the higher CO₂ concentrations because of the larger required plant size and because more of the gas is needed to operate the plant.

Table III-4 compares the economics of using the 30-percent CO₂ gas as a methanol feedstock versus upgrading it for pipeline sales. The table is set up with the value of the gas as methanol feedstock shown in columns "c" to "g" for various plant sizes. The nonfeedstock capital and operating costs, shown near the bottom, come from the Chem Systems study

Table III-3 — Amine Plants for Carbon Dioxide Removal

	Plant Size (MMcfd Raw Gas)					
	2	4	8	16	50	100
CO ₂ Inlet %	30	30	30	30	30	30
CO ₂ Outlet %	2	2	2	2	2	2
MMcfd CO ₂ Removed	0.56	1.12	2.24	4.48	14.00	28.00
GPM Amine Capacity	56	111	222	444	1,389	2,778
Direct Amine Plant	582,609	946,451	1,537,515	2,497,700	5,545,431	9,008,579
Overhead and Engineering @ 50%	291,305	473,226	768,757	1,248,850	2,772,715	4,504,290
Contingencies @ 15%	87,391	141,968	230,627	374,655	831,815	1,351,287
Total Fixed Investment (TFI)	961,305	1,561,645	2,536,899	4,121,205	9,149,961	14,864,155
Total as \$/Mcf	481	390	317	258	183	149
Energy Requirements						
Electric kW/GPM	1.05	1.05	1.05	1.05	1.05	1.05
Thermal (MMBtu/Day/GPM)	2.5	2.5	2.5	2.5	2.5	2.5
Daily Capital and Operating Costs (340 Operating Days/Year)						
Capital @ 20% CRF	\$565	\$919	\$1,492	\$2,424	\$5,382	\$8,744
Electricity @ 5¢/kWh	70	140	280	560	1,750	3,500
Heat @ \$2/MMBtu	278	556	1,111	2,222	6,944	13,889
Direct Labor @ 30K/Yr/Person	265	265	265	353	441	529
Overhead Labor @ 40% Direct	106	106	106	141	176	212
Maintenance @ 5% of TFI	141	230	373	606	1,346	2,186
Insurance & Taxes @ 2% of TFI	57	92	149	242	538	874
Total Daily	\$1,482	\$2,306	\$3,776	\$6,549	\$16,578	\$29,934
Sales Gas MMcfd	1.31	2.61	5.22	10.44	32.63	65.26
\$/Mcf Sales Gas	\$1.14	\$0.88	\$0.72	\$0.63	\$0.51	\$0.46
Gas Use as %	9.4	9.4	9.4	9.4	9.4	9.4

(reported in the appendix) and range from \$0.714 per gallon for the 50-STPD modular plant to \$0.287 per gallon for the conventional 2,500-STPD plant. Because of the considerable economies of scale for methanol plants, the value of the gas increases as the plant size increases. For the 2,500-STPD plant, the gas would be worth \$1.00 in the year 2000 and \$2.02 in 2010.

The right side of the table shows the economics of processing the 30-percent CO₂ gas for pipeline sales. Column "h" shows the assumed wellhead price, which is the Rocky Mountain price used earlier in this report. This price was used because much of the high-CO₂ gas is found there. Column "i" shows the cost of processing the gas in an 8-MMcfd plant. The costs differ by year because the value of the

gas used in the plant changes. Column "j" is the cost of moving the gas to a pipeline, assuming that the distance is 5 miles. The last column is the net value to the producer after subtraction of the gas processing costs and the gathering line costs to the pipeline. The net value of the pipeline sales is much higher than methanol conversion in all years.

Economics of High-Nitrogen Gas

The most commonly used method of removing nitrogen from natural gas is cryogenic distillation. In this process, the gas is cooled below the boiling point of methane (minus 259 degrees Fahrenheit), at which time the liquid methane can be separated from the still-gaseous nitrogen. The gas is cooled by reducing its pressure as it passes through the plant.

Figure III-3 — Cost of Carbon Dioxide Removal

A typical design might have the gas enter the plant's "cold box" at 650 pounds per square inch (psi) and leave at 150 psi before being repressured before sale. Because of their higher freezing points, any carbon dioxide and water in the gas must be removed before the gas is cooled. Therefore, an amine unit and high-efficiency dehydrator are included in the design of the plants.

Costs for nitrogen rejection are shown in Table III-5 for cryogenic plants ranging in size from 2 to 100 MMcfd. These examples are based on the inlet gas containing 30 percent nitrogen and the outlet gas requiring 3 percent or less

nitrogen. The smallest plant has costs of \$1.09 per Mcf of sales gas, while the 100-MMcfd plant costs are \$0.30 per Mcf. Similar cost data are shown graphically in Figure III-4 for gases ranging from 10- to 60-percent nitrogen.

The comparison of converting the example 30-percent nitrogen gas to methanol versus upgrading it for pipeline sales is shown in Table III-6. It is structured the same as the previous table for high-CO₂ gas. The conclusion for the high-nitrogen gas is the same as it was for the high-CO₂ gas: the economics favor pipeline sales in all years.

**Table III-4 — Comparison of Value of High-Carbon-Dioxide Gas as Methanol Feedstock
Versus Pipeline Sales (30 Percent CO₂)**

Year	Methanol Plantgate Value From EIA (90\$/gal)	Value of Natural Gas as Feedstock for Methanol Conversion for Various Plant Sizes (1990\$/MMBtu)					Pipeline Sales Option (90\$ per MMBtu)			
		50 STPD (2.58 MMcf/d) [c]	100 STPD (5.16 MMcf/d) [d]	200 STPD (10.33 MMcf/d) [e]	300 STPD (15.49 MMcf/d) [f]	2,500 STPD (124.9 MMcf/d) [g]	Natural Gas Wellhead Price From EIA [h]	Gas Processing Cost for 8 MMcf/d [i]	Gas Gathering for 8 MMcf/d (5mi to P/L) [j]	Net Wellhead to Producer [h-i-j]
1989	0.261	(3.80)	(1.76)	(0.77)	(0.27)	(0.27)	1.65	0.68	0.07	0.90
1990	0.256	(3.84)	(1.80)	(0.81)	(0.31)	(0.32)	1.68	0.69	0.07	0.93
1991	0.262	(3.79)	(1.74)	(0.75)	(0.26)	(0.25)	1.77	0.70	0.07	1.00
1992	0.269	(3.73)	(1.68)	(0.69)	(0.20)	(0.18)	1.85	0.70	0.07	1.08
1993	0.276	(3.67)	(1.62)	(0.63)	(0.14)	(0.11)	1.95	0.71	0.07	1.16
1994	0.283	(3.61)	(1.56)	(0.58)	(0.08)	(0.04)	2.04	0.72	0.07	1.25
1995	0.290	(3.55)	(1.51)	(0.52)	(0.02)	0.04	2.14	0.74	0.07	1.34
1996	0.308	(3.40)	(1.36)	(0.37)	0.13	0.22	2.32	0.75	0.07	1.49
1997	0.326	(3.25)	(1.20)	(0.21)	0.28	0.40	2.51	0.77	0.07	1.66
1998	0.345	(3.09)	(1.04)	(0.06)	0.44	0.60	2.71	0.80	0.07	1.85
1999	0.365	(2.93)	(0.88)	0.11	0.60	0.80	2.93	0.82	0.07	2.04
2000	0.385	(2.76)	(0.71)	0.28	0.77	1.00	3.17	0.84	0.07	2.25
2001	0.396	(2.67)	(0.62)	0.36	0.86	1.11	3.38	0.87	0.07	2.44
2002	0.406	(2.58)	(0.53)	0.46	0.95	1.22	3.60	0.89	0.07	2.64
2003	0.417	(2.49)	(0.44)	0.55	1.04	1.33	3.83	0.91	0.07	2.85
2004	0.428	(2.39)	(0.35)	0.64	1.13	1.45	4.08	0.94	0.07	3.07
2005	0.440	(2.30)	(0.25)	0.73	1.23	1.56	4.35	0.97	0.07	3.31
2006	0.448	(2.23)	(0.18)	0.81	1.30	1.65	4.59	0.99	0.07	3.52
2007	0.457	(2.15)	(0.11)	0.88	1.38	1.74	4.84	1.02	0.07	3.75
2008	0.466	(2.08)	(0.03)	0.96	1.45	1.84	5.10	1.05	0.07	3.98
2009	0.475	(2.00)	0.04	1.03	1.53	1.93	5.38	1.08	0.07	4.23
2010	0.484	(1.92)	0.12	1.11	1.60	2.02	5.67	1.11	0.07	4.50
Nongas										
methanol cost \$/gal:		0.714	0.470	0.352	0.293	0.287				
MMBtu natural gas/gal:		0.1193	0.1193	0.1193	0.1193	0.098				

Table III-5 — Cryogenic Plants for Nitrogen Rejection

	Plant Size (MMcfd Raw Gas)					
	2	4	8	16	50	100
Nitrogen Inlet %	30	30	30	30	30	30
CO ₂ Inlet %	3	3	3	3	3	3
Feed Gas Compression from 600 to 650 psi (BHP)	8	16	32	64	200	400
CO ₂ % into NRU	0	0	0	0	0	0
MMcfd CO ₂ Removed	0.06	0.12	0.24	0.48	1.50	3.00
GPM Amine Capacity	6	12	24	48	149	298
MMcfd Gas into NRU	1.94	3.88	7.76	15.52	48.5	97
MMcfd Nitrogen Rejected (92%)	0.55	1.10	2.21	4.42	13.80	27.60
MMcfd HC Gas Use and Loss	0.08	0.15	0.31	0.62	1.92	3.85
MMcfd Sales Gas	1.31	2.62	5.24	10.49	32.78	65.55
Sales Gas Compression from 150 to 600 psi (BHP)	111	223	446	892	2,786	5,572
Capital Costs						
Dehydrator	72,754	110,275	167,146	253,346	501,907	760,749
Amine Plant	121,998	198,186	321,954	523,015	1,161,207	1,886,386
Compressors	59,721	119,442	238,885	477,770	1,493,030	2,986,061
Cold Box	447,886	690,735	1,065,259	1,642,854	3,348,731	5,164,450
Total Direct	702,360	1,118,638	1,793,244	2,896,985	6,504,875	10,797,645
Overhead and Engineering @ 50%	351,180	559,319	896,622	1,448,492	3,252,438	5,398,823
Contingencies @ 15%	105,354	167,796	268,987	434,548	975,731	1,619,647
Total Fixed Investment	1,158,893	1,845,753	2,958,852	4,780,025	10,733,044	17,816,115
Total as \$/Mcf Raw Gas	579	461	370	299	215	178
Energy Requirements						
Amine						
Electric kW/GPM	1.05	1.05	1.05	1.05	1.05	1.05
Thermal (MMBtu/Day/GPM)	2.5	2.5	2.5	2.5	2.5	2.5
Compressors (MMBtu/Day/BHP)	0.192	0.192	0.192	0.192	0.192	0.192
Miscellaneous Electric kW	50	70	100	150	390	740
Total Electric kW	56	83	125	200	546	1,053
Total Gas (MMBtu/Day)	37.8	75.6	151.3	302.5	945.3	1,890.7
Daily Capital and Operating Costs (340 Operating Days/Year)						
Capital @ 20% CRF	\$682	\$1,086	\$1,741	\$2,812	\$6,314	\$10,480
Electricity @ 5¢/kWh	68	99	150	240	656	1,263
Heat @ \$2/MMBtu	76	151	303	605	1,891	3,781
Direct Labor @ 30K/Year/Person	265	265	265	353	441	529
Overhead Labor @ 40% Direct	106	106	106	141	176	212
Maintenance @ 5% of TFI	170	271	435	703	1,578	2,620
Insurance & Taxes @ 2% of TFI	68	109	174	281	631	1,048
Total Daily	\$1,434	\$2,087	\$3,173	\$5,135	\$11,687	\$19,934
Sales Gas MMcfd	1.31	2.62	5.24	10.49	32.78	65.55
\$/Mcf Sales Gas	\$1.09	\$0.80	\$0.60	\$0.49	\$0.36	\$0.30
Gas Use and Loss as %	5.7	5.7	5.7	5.7	5.7	5.7

Figure III-4 — Cost of Nitrogen Removal

Note: 3% CO₂ in feed, 3% or less N₂ outlet

**Table III-6 — Comparison of Value of High-Nitrogen Gas as Methanol Feedstock
Versus Pipeline Sales (30 Percent Nitrogen)**

Year	Methanol Plantgate Value From EIA (1990\$/gal)	Value of Natural Gas as Feedstock for Methanol Conversion for Various Plant Sizes (1990\$/MMBtu)					Pipeline Sales Option (1990\$/MMBtu)			
		50 STPD (2.58 MMcfd) [c]	100 STPD (5.16 MMcfd) [d]	200 STPD (10.33 MMcfd) [e]	300 STPD (15.49 MMcfd) [f]	2,500 STPD (124.9 MMcfd) [g]	Natural Gas Wellhead Price From EIA [h]	Gas Processing Cost for 8 MMcfd [i]	Gas Gathering for 8 MMcfd (5mi to P/L) [j]	Net Wellhead to Producer [h-i-j]
1989	0.261	(3.61)	(1.76)	(0.86)	(0.43)	(0.47)	1.65	0.59	0.07	0.99
1990	0.256	(3.65)	(1.80)	(0.89)	(0.46)	(0.51)	1.68	0.59	0.07	1.02
1991	0.262	(3.60)	(1.75)	(0.84)	(0.41)	(0.45)	1.77	0.59	0.07	1.10
1992	0.269	(3.55)	(1.70)	(0.79)	(0.36)	(0.39)	1.85	0.60	0.07	1.19
1993	0.276	(3.50)	(1.65)	(0.74)	(0.31)	(0.32)	1.95	0.60	0.07	1.28
1994	0.283	(3.44)	(1.60)	(0.69)	(0.26)	(0.26)	2.04	0.60	0.07	1.37
1995	0.290	(3.39)	(1.54)	(0.64)	(0.20)	(0.20)	2.14	0.60	0.07	1.47
1996	0.308	(3.26)	(1.41)	(0.50)	(0.07)	(0.03)	2.32	0.61	0.07	1.64
1997	0.326	(3.12)	(1.27)	(0.37)	0.06	0.13	2.51	0.61	0.07	1.82
1998	0.345	(2.98)	(1.13)	(0.23)	0.20	0.30	2.71	0.62	0.07	2.02
1999	0.365	(2.84)	(0.99)	(0.08)	0.35	0.48	2.93	0.63	0.07	2.23
2000	0.385	(2.69)	(0.84)	0.07	0.50	0.66	3.17	0.63	0.07	2.46
2001	0.396	(2.61)	(0.76)	0.15	0.58	0.76	3.38	0.64	0.07	2.67
2002	0.406	(2.53)	(0.68)	0.22	0.66	0.86	3.60	0.65	0.07	2.88
2003	0.417	(2.45)	(0.60)	0.31	0.74	0.96	3.83	0.65	0.07	3.11
2004	0.428	(2.37)	(0.52)	0.39	0.82	1.06	4.08	0.66	0.07	3.35
2005	0.440	(2.28)	(0.43)	0.47	0.90	1.16	4.35	0.67	0.07	3.61
2006	0.448	(2.22)	(0.37)	0.54	0.97	1.24	4.59	0.67	0.07	3.84
2007	0.457	(2.15)	(0.30)	0.60	1.03	1.32	4.84	0.68	0.07	4.09
2008	0.466	(2.09)	(0.24)	0.67	1.10	1.40	5.10	0.69	0.07	4.34
2009	0.475	(2.02)	(0.17)	0.74	1.17	1.48	5.38	0.70	0.07	4.61
2010	0.484	(1.95)	(0.10)	0.81	1.24	1.57	5.67	0.71	0.07	4.90
Nongas										
methanol cost \$/gal:		0.747	0.498	0.376	0.318	0.312				
MMBtu natural gas/gal:		0.1346	0.1346	0.1346	0.1346	0.110				

IV. CONVERSION OF DOMESTIC PIPELINE GAS TO METHANOL

INTRODUCTION

The cost of producing methanol from domestic pipeline gas in three representative U.S. metropolitan areas for the year 2000 is estimated in this chapter. That cost is compared with the cost of gasoline and imported methanol. By 2000, a significant demand for methanol as an alternative transportation fuel may exist in at least some metropolitan areas.

For domestically produced methanol to be economic, it must be competitive with gasoline and imported methanol. To minimize the feedstock cost, a plant using domestic natural gas should be located close to a pipeline and, if possible, be able to purchase its feedstock under favorable price terms, such as those available by virtue of large volume usage, spot market purchases, and willingness to accept interruptible service. To have a transportation cost advantage, the plant must be located near a major market for methanol. Moreover, the transportation advantage will be greatest for inland cities, because imported methanol will have to be transshipped by barge, rail, or truck, resulting in a higher price.

The cost of producing methanol in Atlanta, Chicago, and El Paso is examined. All three cities have access to pipeline gas and are inland. Moreover, all are serious or severe ozone nonattainment areas; consequently, methanol as a transportation fuel to reduce emissions may be considered for these cities. The cost of domestically produced methanol is compared with the gasoline price and the price of methanol imported from three prospective low-cost suppliers: Saudi Arabia, Qatar, and Argentina.

The analysis presented here depends on several variables that cannot be projected with a high degree of reliability. Accordingly, in conducting the analysis, optimistic assumptions have been used throughout. If under the optimistic assumptions it appears economic to convert domestic gas to methanol, then a more detailed analysis may be justified. If, however,

the process is judged to be uneconomic, even with optimistic assumptions, a more detailed analysis would be unnecessary.

AVAILABILITY AND COST OF GAS

A primary determinant in the economics of domestic methanol production is the supply of natural gas feedstock. Consequently, availability and cost of the natural gas supply to the plantgate are critical to the competitiveness of domestic production. The following three primary factors influence the cost of natural gas to an industrial facility:

- The facility's size and its siting for interconnection with existing natural gas transmission and distribution systems.
- The terms under which natural gas supplies are procured.
- The overall condition of the market for natural gas during the period of operation.

Facility Siting

The domestic methanol plant considered in this analysis has been sized at an output of 2,500 STPD and would require an annual gas feedstock supply of approximately 25 bcf. As Table IV-1 shows, the construction of one plant would represent a significant increase in both industrial-sector and total gas consumption in each of the three cities. The plant would consume approximately 75 MMcf of natural gas per day of operation, ranking with the largest industrial facilities currently served by gas systems.

Based on discussions with representatives of the local gas distribution companies (LDC's) serving the study cities, new industrial gas loads of this size could be served from one or more locations on the existing distribution systems. A siting study would be required at the time of the plant's design to identify existing high-pressure distribution lines with available

**Table IV-1 — Comparison
of Gas Feedstock Consumption
by 2,500 Ton-per-Day Methanol Plant
to Current Gas Consumption
in Study Cities**

Study City	Current Consumption ¹ (Trillion Btu's)		Incremental Gas Load for 25 bcf/yr Methanol Plant (Percent)	
	Total	Industrial	Of Total	Of Industrial
Atlanta, GA ²	248	116	10.1	21.5
Chicago, IL ³	668	205	3.7	12.2
El Paso, TX ⁴	140	NA	18.0	NA

¹Include gas utility sales and volumes transported for the account of end-users.

²Data represent fiscal year 1989 sales of Atlanta Gas Light Co.

³Data represent fiscal year 1987 sales of Northern Illinois Gas Co., North Shore Gas Co., and Peoples Gas Light and Coke Co.

⁴Data represent 1984 annual sales of Southern Union Co. Company serves a multistate region including Texas, New Mexico, Oklahoma, and Arizona.

capacity or locations where high-pressure lines could be extended at low cost. A plant of this size could also consider direct attachment to a gas pipeline system if a suitable site located near an existing transmission line could be found. A cost would be incurred for the final delivery of gas to the plant from the pipeline system serving the city. If the plant were attached to a distribution system, the cost would be an LDC charge for the use of its facilities. If the plant were attached directly to a pipeline, the cost would be that for the construction of needed new facilities. Which alternative is more economic would depend on the specific circumstances of siting and on the ability shown by many LDC's to offer rates that are competitive with direct pipeline connection.

In keeping with the use of optimistic assumptions in this analysis, no allowance has been made for any substantial costs for the final delivery of gas feedstock to the methanol plant. Thus, the actual costs for conversion of domestic pipeline gas to methanol in all likelihood will be *higher* than those developed here.

Natural Gas Supply Procurement

An industrial facility may purchase natural gas under a range of gas supply arrangements. Firm agreements provide an assurance of

year-round service by reserving adequate capacity in natural gas production, transmission, storage, and distribution systems to meet the maximum daily requirements of all firm customers. Interruptible agreements provide for the use of gas supply and transportation systems when the maximum capacity is not required by firm customers. In particular, interruptible customers will be required to switch to an alternate fuel or to suspend operations during periods when firm demands are large and system capacity is fully utilized. Firm service is more reliable and more expensive than interruptible service, as the result of higher average prices paid for natural gas at the wellhead and the costs of the transmission, storage, and distribution systems needed to serve firm customers. In general, large industrial customers with the capability to use alternate fuels or suspend operations will select interruptible service.

If interconnected with an LDC, a plant may purchase natural gas under the company's published interruptible tariffs. Alternately, industrial customers may purchase gas directly from producers and arrange transportation services for delivery to the plantgate. Since 1985, the open-access transportation policies of the Federal Energy Regulatory Commission (FERC) and State public utility commissions have fostered the development of a large spot market for natural gas, which has become the predominant procurement mechanism for large, price-competitive interruptible gas loads.

For the purposes of this analysis, a domestic methanol plant is assumed to procure its feedstock under a gas supply arrangement characterized as follows:

- Spot market purchases directly from producers or gas marketers, at an annual-average discount to U.S. average well-head gas prices.
- Interruptible pipeline transportation, which under FERC policy may be discounted below the maximum authorized rates.

In keeping with the optimistic economic assumptions used throughout this analysis, market conditions in the year 2000 are assumed to continue to allow spot/interruptible gas procurement at a discount to average annual gas prices. To the extent that future market conditions differ from this assumption,

**Figure IV-1 — Hypothetical Seasonal Natural Gas Loads and Supply Availability
(Winter Heating Season)**

the costs of methanol conversion from pipeline gas could be higher than those developed here.

Interruptible Gas Availability

As illustrated in Figure IV-1, the availability of gas to interruptible customers is affected by the seasonal character of the overall demand for natural gas and the operating characteristics of specific gas pipeline and distribution systems. As temperatures fall during the winter heating season, residential heating and other firm customers place increasing demands on the system. In periods when the demand by all customers exceeds the mainline pipeline capacity from production areas, the total supply of gas may be increased by withdrawing gas from underground storage.

As total demand reaches the limits of the capacity to deliver gas from production areas and storage fields, interruptible customers are curtailed to divert the available gas supply to meet firm customer requirements. Peakshaving

facilities (which produce natural gas substitutes such as propane-air mixtures) are located within market areas and are used to meet the additional firm customer demands that occur under the most extreme weather conditions experienced in the winter.

The frequency of the curtailments experienced by an interruptible customer will depend on the configuration and operating characteristics of the supplying pipeline, including the pipeline's mainline capacity to production areas and its ability to deliver gas from storage fields, and on the customer's location on the pipeline system. The frequency also will depend on the seasonal nature of firm demands in the same market area and on the actual weather.

In general, the reliability of interruptible service is increased (the frequency of curtailment reduced) when underground storage services are available to meet customer requirements. In the example shown in the figure, an interruptible customer would experience approximately 30 days of curtailment if underground

storage services were available for use, and approximately 60 days if the customer were supplied solely by mainline pipeline capacity from production areas. In general, interruptible transportation customers do not have easy access to underground storage facilities and, thus, depend on the availability of mainline pipeline capacity.

Table IV-2 summarizes the recent experience in the study cities for the curtailment of interruptible transportation and illustrates the degree to which this depends on the seasonal characteristics of specific pipelines and market areas. These data are based on discussions with representatives of the gas pipeline companies serving the study cities and reflect the typical number of days on which interruptible transportation capacity is curtailed during the course of a winter. Interruptible transportation capacity typically is curtailed for periods ranging from 1 to 20 days in each of the three study cities, depending on the supplying pipeline. Curtailments would last for periods ranging from several hours to several days and could occur one or more times during the winter.

However, a plant served only from the Transcontinental pipeline system would be curtailed on a nearly continuous basis through most of the winter. Based on discussions with pipeline company representatives, a plant sited in El Paso would receive interruptible service with a very low probability of curtailment because it is near a major gas-producing area.

Interruptible Gas Pricing

The price of interruptible gas supply also varies with the season. With the development of a large and competitive market, spot gas prices in the past 3 years have shown the tendency to rise significantly in the winter and to fall back in the spring and summer months. This variability is caused by seasonal changes in the demand for gas and transportation relative to the existing supply and capacity available. Both producer wellhead prices and the rates charged by pipelines for interruptible transportation can be discounted in this competitive market in response to the changing seasonal supply-demand balance. This behavior is likely to be characteristic of future gas markets.

Using data reported in a gas industry periodical, Figure IV-2 shows the actual monthly

Table IV-2 — Curtailment Experience for Interruptible Pipeline Transportation

Study City	Pipeline	Number of Days of Interruptions per Year (1986-1990)
Atlanta, GA	Transcontinental Gas Pipeline Co.	> 60 ^a
	Southern Natural Gas Co.	15-20
Chicago, IL	Natural Gas Pipeline Co. of America	1-5 ^b
El Paso, TX	El Paso Natural Gas Co.	0

^aInterruptible transportation to this market area is generally unavailable during winter period (November to March).

^bRepresents availability of interruptible transportation on Gulf Coast leg of pipeline. Interruptible transportation capacity out of the Oklahoma Triangle area (Amarillo line) is limited during peak winter months (December to February).

Source: Discussions with gas pipeline representatives.

variation during 1989 of the price of spot gas delivered to citygates in the lower Midwest region (corresponding to the Chicago study city). In 1989, citygate spot prices peaked during January at \$2.45 per MMBtu and then fell sharply in March, at the end of the winter heating season, to \$1.77 per MMBtu. Citygate prices in the following off-peak period traded in a range from \$1.69 to \$1.83 until the beginning of the following heating season in November. Overall, delivered spot prices averaged \$2.16 per MMBtu during the 5 heating season months (November through March) and \$1.75 per MMBtu during the remaining off-peak months.

As the figure illustrates, seasonal variability occurs in both the wellhead price of gas and in the total transportation costs charged between the wellhead and citygate. Although related to the seasonality of the natural gas market in both instances, seasonal wellhead prices and transportation rates respond to the following different factors:

- Spot wellhead prices are influenced most strongly by the overall seasonal balance between deliverability (supply) and the demand of buyers in the production areas. The markets for gas supply in the major production areas of the U.S. Southwest

Figure IV-2 — Seasonal Variation in Spot Gas Wellhead Prices and Transportation Costs in the Lower Midwest Region

Source: NGI Price Index

are composed of many suppliers and buyers from widely dispersed markets. Aggregate factors such as the overall deliverability of gas and demand across many market areas tend to be important, and no single gas buyer is likely to have a significant effect on prices in a large and highly competitive market of this kind.

- The rates charged for interruptible pipeline transportation are influenced most strongly by the seasonal throughput on individual pipeline systems and the degree of competition among pipelines serving the same market. FERC ratemaking practices establish minimum and maximum rates for open-access transportation services and allow the pipeline and its shippers to negotiate the rates actually charged within this range. Thus, individual business decisions and the competitive factors in specific markets can have a significant impact on the transportation rates actually charged.

Projected Gas Prices

Although seasonal considerations are important to the understanding of natural gas markets, this analysis evaluates domestic metha-

nol production on the basis of annual-average economics. The price of natural gas feedstock delivered to the methanol plantgate has been estimated from the following:

- Specific assumptions regarding the wellhead origin and the transportation routes used to deliver spot gas to each of the three study cities.
- Data on the pricing relationships in the spot market during 1989, including regional differences in wellhead gas prices and the actual annual-average rates charged for transportation services.
- Projections of future U.S. wellhead gas prices prepared by the EIA and considerations of future market conditions.

Spot Market Pricing Relationship

Table IV-3 summarizes the transportation routing assumptions and the spot market pricing relationships used. Transportation routes have been chosen for each study city based on the following:

- The major interstate pipeline serving each city. These pipelines are Southern Natural

**Table IV-3 — Transportation Routing Assumptions
and Actual 1989 Average Spot Gas Costs for Study Cities**

	Atlanta, GA	Chicago, IL	El Paso, TX
Transportation Routing Assumptions			
Pipeline	SONAT	NGPA	EPNG
Wellhead Origin	Louisiana	Texas	Texas
Received At	Southern Louisiana	East Texas	West Texas
Delivered To	South Atlantic	Lower Midwest	West Texas
Actual 1989 Average Costs (\$/MMBtu)			
Spot Wellhead Price	1.61	1.51	1.51
Production Area Charges ¹	0.14	0.14	0.13
Delivered to Pipeline Price	1.75	1.65	1.64
Interruptible Mainline Pipeline Transportation Charges ²	0.39	0.27	0.18
Delivered to Citygate	2.14	1.92	1.82

¹Estimated from reported wellhead, pipeline receipt, and citygate prices.

²Inclusive of fuel, GRI, and ACA charges where applicable.

Source: *Natural Gas Intelligence Gas Price Index*.

(SONAT) serving Atlanta, Natural Gas Pipeline Company of America (NGPCA) serving Chicago, and El Paso Natural Gas (EPNG) serving El Paso.

- A wellhead origin point depending on the supply sources and configuration of each pipeline. These are Louisiana for SONAT and Texas for NGPCA and EPNG.
- A production area receipt point on each pipeline system as reported in the industry periodical.
- A regional citygate delivery point corresponding to each study city as reported in the industry periodical.

Annual-average spot prices have been estimated for each city at three points in the delivery chain: at the wellhead, at the mainline pipeline receipt point, and at the citygate. Differences in the reported prices are then taken to estimate regional price relationships and the actual charges for transportation services between the wellhead and citygate. The transportation charges consist of production area services such as gathering and short-haul transportation to deliver gas to the mainline pipeline receipt point. Additional transportation charges then must be paid by shippers for mainline transmission to the citygate delivery point. For all three study

cities, the estimated average rates for mainline pipeline transportation are consistent with seasonal discounting at a level between the minimum and maximum rates approved for these pipelines.

For example, interruptible spot gas supplies delivered to Atlanta are assumed to originate at a Louisiana wellhead and to be received by the SONAT pipeline system in southern Louisiana for delivery to Georgia. The 1989 data indicate that, at \$1.61 per MMBtu, Louisiana spot wellhead prices averaged \$0.10 per MMBtu above those in Texas and an average production area charge of \$0.14 per MMBtu was paid for delivery to the mainline receipt point. The average mainline transportation charge for delivery to the South Atlantic region was estimated at \$0.39 per MMBtu. On an annual basis, spot gas was delivered to this area in 1989 at an average price of \$2.14 per MMBtu.

Projected Gas Feedstock Costs

Perhaps the most important assumption in projecting the delivered cost of the methanol plant's natural gas feedstock is the future wellhead price of natural gas in the United States. EIA prepares an annual analysis of the outlook for U.S. energy supply and demand. In its 1990 mid-case scenario, EIA projects that

U.S. average wellhead gas prices will increase significantly in real terms (constant 1989 dollars) from \$1.66 per MMBtu in 1989 to \$3.14 per MMBtu (\$3.23 per Mcf) in the year 2000.

The projected price represents an average for all U.S. production, including both spot market and long-term contract gas sales. EIA does not separately project spot market gas prices. The relationship between U.S. average and spot market wellhead prices depends upon several factors, including the overall balance between gas deliverability and demand, the terms of long-term contracts for gas supply, and the mix of spot and long-term sales occurring in the market.

Table IV-4 summarizes the projected spot wellhead prices used in this analysis. Under the conditions existing in 1989, the Southwest-average spot wellhead price of \$1.51 per MMBtu was discounted 9 percent (or \$0.15 per MMBtu) below the U.S. average wellhead price of \$1.66 per MMBtu. For this analysis, spot wellhead prices are assumed to maintain the 9-percent discount below the U.S. average price in the year 2000, resulting in a \$0.28-per-MMBtu discount at the higher average price

Table IV-4 — Natural Gas Wellhead Price Assumptions
(1989 dollars per MMBtu)

	1989 Actual	2000 Projection
U.S. Average Wellhead Price ¹	1.66	3.14
Southwest Average Spot Wellhead Price ²	1.51	2.86
Regional Spot Wellhead Prices ³		
Louisiana	1.61	2.96
Texas	1.51	2.86

¹ Assumption for the year 2000 based on the EIA midcase projection (\$3.23 per Mcf in 1989 dollars).

² Southwest regional average reported by the *Natural Gas Intelligence Gas Price Index*. Projection for the year 2000 based on continuation of the 9-percent discount below U.S. average wellhead price observed in 1989.

³ Based on Southwest average spot price with continuation of regional differences observed in 1989.

level projected to prevail. Regional spot wellhead prices for Louisiana and Texas then are estimated from the Southwest average based on the regional price relationships observed in 1989.

These assumptions for spot market prices reflect an optimistic outlook for future spot wellhead prices of natural gas, in that they imply continuing steep discounts under future market conditions. Most industry analysts believe that spot wellhead gas prices continued to be depressed in 1989 by the surplus of gas deliverability that prevailed during much of the 1980's. Under the widely held expectation that the surplus will end in the early 1990's, a narrowing of the spot discount versus the U.S. average could be expected to occur. To the extent future market conditions differ in this regard, spot wellhead prices would be higher than assumed here.

Table IV-5 shows the projected prices for natural gas feedstock delivered to the methanol plantgate in each of the study cities. The plantgate prices are estimated by adding production area charges and mainline transportation costs to the average spot wellhead prices in the regional supply areas. Production area charges are assumed to remain constant at 1989 levels. The projected rates for mainline pipeline transportation have been based on an explicit scenario for seasonal transportation rate discounting:

- For the 5 months of the winter heating season, each pipeline is assumed to charge the maximum authorized rate.
- For the 7 months of the off-peak season, each pipeline is assumed to charge only the minimum authorized rate.

The authorized minimum and maximum rates have been taken from current (1989 or 1990) rate schedules and adjusted to include allowances for fuel costs and the GRI and FERC Annual Charge Adjustment (ACA) surcharges levied on interstate deliveries. In each instance, this discounting scenario produces a lower mainline transportation rate than actually charged on average in 1989. Again, the citygate-delivered prices for pipeline gas developed here reflect optimistic assumptions regarding the costs of natural gas feedstock in the year 2000. To the extent that future market

Table IV-5 — Projected Natural Gas Feedstock Costs for the Year 2000
(1989 dollars per MMBtu)

	Study City		
	Atlanta, GA	Chicago, IL	El Paso, TX
Spot Market Wellhead Price ¹			
Louisiana	2.96	—	—
Texas	—	2.86	2.86
Production Area Charges ²	.14	.14	.13
Interruptible Mainline Pipeline Transportation ³	.28	.23	.15
Delivered to Methanol Plantgate	3.38	3.23	3.14

¹See Table IV-3.

²Based on production area charges estimated for 1989.

³Annual average transportation rate based on maximum rate during 5-month winter heating season and minimum rate during 7-month off-peak period.

conditions differ from those assumed here, the costs of methanol conversion could be higher.

COST OF METHANOL PRODUCTION

Capital Costs of Methanol Plant

A methanol plant with a capacity of 2,500 STPD, requiring a feedstock supply of 25 bcf per year, is assumed in this cost analysis.* Total fixed investment for such a plant amounts to \$236.3 million. Adding to this an estimated \$18.2 million for working capital gives total capital requirements of \$254.5 million. In fact, if the plant were to purchase its feedstock under an interruptible contract, it probably would choose to maintain a larger methanol inventory to provide for the periods when production was suspended, which would raise the capital costs above the figures presented.

Methanol Production Costs

Table IV-6 presents the production costs, per gallon of methanol produced, for the 2,500-STPD methanol plant. The costs are broken down into capital costs, feedstock costs, and other production costs. The capital charge is

based on the capital costs presented above, using a capital recovery factor of 20 percent (which corresponds roughly to a 10-percent real, after-tax rate of return). It is likely that a higher rate of return would be required to compensate investors for the added risk of obtaining the feedstock under an interruptible contract, in which case the production costs would be correspondingly higher.

A 2,500-STPD plant, if operated year round, would have a capacity of 250 million gallons per year, assuming that, after allowing for scheduled maintenance, the plant operates at 90 percent of rated capacity. The capital charge is \$0.19 per gallon of methanol produced. If the plant purchases feedstock under an interruptible transportation contract, it will have to suspend operations when the feedstock supply is interrupted. But, in keeping with the use of favorable assumptions, it is assumed that scheduled plant maintenance can be timed to coincide with any suspensions in feedstock delivery, so that the plant is able to operate at 90 percent of rated capacity. With this assumption, annual output is equal to the maximum output normally associated with the plant, or 250 million gallons of methanol per year. If interruptions in feedstock supply were to require unscheduled plant shutdowns, the capital charge would have to be allocated over a lower rate of output and would be higher than \$0.19 per gallon.

*See Appendix A for detailed assumptions regarding methanol plant configuration and costs.

**Table IV-6 — Cost of M85
With Methanol from U.S. Pipeline Gas
for the Year 2000
Based on 2,500-STPD Methanol Plant
(1989 dollars per gallon)**

	Atlanta	Chicago	El Paso
Delivered Cost of Gas (/MMBtu)	3.38	3.23	3.14
Methanol Conversion Costs			
Feedstock Costs	0.33	0.32	0.31
Capital Recovery	0.19	0.19	0.19
Nonfeedstock Operating Costs	<u>0.11</u>	<u>0.11</u>	<u>0.11</u>
Wholesale Price	0.63	0.62	0.61
Gasoline Wholesale Price *	0.96	0.96	0.96
M85 Wholesale (85:15)	0.68	0.67	0.66
Distribution			
Terminal	0.02	0.02	0.02
Trucking	0.01	0.01	0.01
Outlet Markup	<u>0.12</u>	<u>0.12</u>	<u>0.12</u>
Total Distribution	0.15	0.15	0.15
M85 Pump Price Less Taxes	0.83	0.82	0.81
Taxes			
Federal Fuel Tax**	0.05	0.05	0.05
State Fuel Tax	0.05	0.05	0.05
Sales Tax @ 5%	<u>0.04</u>	<u>0.04</u>	<u>0.04</u>
Total Taxes	0.13	0.13	0.13
M85 Pump Price	0.96	0.95	0.94
M85 @ Gasoline Equivalent (1:1.74)	1.67	1.65	1.64

*Based on EIA national average gasoline retail price of \$1.31 per gallon.

**Does not include tax increase that went into effect on December 1, 1990.

Feedstock use is 0.098 Mcf of natural gas per gallon of methanol produced. Based on the natural gas prices presented above, the feedstock costs per gallon of methanol produced are \$0.31 to \$0.33 for the three cities, as shown in Table IV-6.

Operating costs other than feedstock are estimated to be \$0.11 per gallon of methanol. These costs include the costs of raw materials (other than feedstock), utilities, labor costs, other operating costs, and overhead. With the exception of raw materials, most of these costs would be incurred even during periods when the plant is idle. If the plant were forced to shut down because of an interruption in feedstock deliveries, these costs still would be incurred and, on a per-gallon basis, would raise the total production cost.

Plantgate and Retail Prices

Adding together the capital charge, feedstock costs, and other operating costs gives plantgate prices of \$0.63 per gallon for Atlanta, \$0.62 per gallon for Chicago, and \$0.61 per gallon for El Paso. This is the price free on board (f.o.b.) at the production facility. It is assumed that the methanol plant is located adjacent to the distribution terminal so that no costs are incurred in moving the methanol from the plant to the terminal. Consequently, the wholesale price is equal to the plantgate price.

The methanol is to be blended in an 85-to-15 ratio with gasoline, which is assumed to have a wholesale price of \$0.96 in the year 2000, based on the EIA forecast of a national average retail price of \$1.31 per gallon. Adding in distribution costs and taxes gives a pump price for M85 of \$0.96 for Atlanta, \$0.95 for Chicago, and \$0.94 for El Paso. Because of the lower energy content of M85 relative to gasoline, its price is multiplied by 1.74 to bring it to an equivalent basis. The gasoline-equivalent prices for M85 are \$1.67 for Atlanta, \$1.65 for Chicago, and \$1.64 for El Paso. These prices are 25 to 27 percent more than the expected retail price of gasoline.

PRICE COMPARISONS WITH IMPORTED METHANOL

The estimated price of methanol imported from three representative foreign countries and delivered to each of the three cities considered in this report is shown in Table IV-7. The three foreign countries selected are Saudi Arabia, Qatar, and Argentina. Natural gas prices, and therefore feedstock costs, are projected to be significantly lower in these countries. Each country has a large volume of discovered but undeveloped gas reserves for which there is

comparatively little demand. For example, Saudi Arabia and Qatar, respectively, have an estimated 97 and 128 tcf of discovered but undeveloped reserves that could be produced at \$0.55 per Mcf or less.* In the Western Hemisphere, Argentina is estimated to have 12 tcf of gas that could be produced at \$1.42 per Mcf or less.† For estimating the price of im-

*Energy and Environmental Analysis Inc., "Cost of Development of Non-Associated Gas Reserves in Selected Countries," July 1990 report to DOE.

†Ibid.

**Table IV-7 — Cost of M85 With Methanol From Foreign Countries for the Year 2000
(1989 dollars per gallon)**

Cost Factor	Country of Origin								
	Saudi Arabia			Qatar			Argentina		
Cost of Natural Gas (\$/Mcf)	0.70			0.70			1.50		
Methanol Conversion Costs									
Feedstock Costs	0.06			0.06			0.14		
Capital Recovery	0.12			0.17			0.17		
Non-Feedstock Operating Costs	<u>0.06</u>			<u>0.07</u>			<u>0.07</u>		
Price in Country of Origin	0.24			0.30			0.38		
	Destination								
	Atlanta	Chicago*	El Paso	Atlanta	Chicago*	El Paso	Atlanta	Chicago	El Paso
Shipping to U.S. Port	0.09	0.09	0.10	0.09	0.09	0.10	0.08	0.08	0.08
Lightering and Barging	0.00	0.04	0.00	0.00	0.04	0.00	0.00	0.04	0.00
Wholesale Methanol Price	0.33	0.37	0.35	0.39	0.43	0.41	0.45	0.49	0.46
M85 Wholesale (85:15)	0.43	0.46	0.44	0.48	0.51	0.49	0.53	0.56	0.53
Terminal Charge	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Trucking Charge	0.07	0.01	0.19	0.07	0.01	0.19	0.07	0.01	0.19
Outlet Markup	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
M85 Pump Price Less Taxes	0.63	0.61	0.76	0.68	0.66	0.81	0.73	0.71	0.86
Total Taxes	0.12	0.12	0.13	0.12	0.12	0.13	0.13	0.13	0.13
M85 Pump Price	0.75	0.73	0.89	0.81	0.78	0.94	0.86	0.84	0.99
M85 @ Gasoline Equivalent (1:1.74)	1.31	1.26	1.55	1.40	1.36	1.64	1.49	1.46	1.72

Notes: EIA gasoline pump price for 2000 is \$1.310 per gallon.
Imputed gasoline wholesale price is \$0.959 per gallon.
Shipping cost based on bunker fuel cost of \$22.00 per barrel.

*Assumes transport through Great Lakes. In winter M85 pump price costs would be higher by \$0.009 per gallon for shipments from the Persian Gulf because of need to ship through Mississippi/Illinois waterway.

ported methanol, a wellhead natural gas price in the year 2000 (1989 dollars) of \$0.70 is used for Saudi Arabia and Qatar and \$1.50 for Argentina.

By locating a methanol plant near a large natural gas field, a plant with a capacity of 10,000-STPD can be built, resulting in lower capital costs. The cost of production is lower for imported methanol than for domestic methanol both because of the cheaper feedstock and the lower capital investment required. However, transportation costs are higher for imported methanol, particularly when delivered to an inland city.

Table IV-7 contains estimated plantgate prices for methanol produced in Saudi Arabia, Qatar, and Argentina, respectively, in the year 2000. In all three cases, a 10,000-STPD plant has been assumed. The capital investment is estimated to be \$679.4 million in Saudi Arabia and \$919.2 million in Qatar and Argentina.* As Table IV-7 shows, the plantgate price ranges from \$0.24 per gallon in Saudi Arabia to \$0.38 in Argentina. Table IV-7 also shows the cost of methanol imported from each of the three countries and delivered to the three U.S. cities. The methanol is assumed to be shipped by tanker to Savannah (approximately 16,900 nautical miles round-trip from the Persian Gulf and 13,790 from the south end of Argentina) then trucked 255 miles to Atlanta. Adding the additional distribution costs and taxes to the wholesale price results in a gasoline-equivalent pump price for M85 ranging from \$1.31 per gallon for Saudi Arabia to \$1.49 per gallon for Argentina. Thus the price of methanol from all three countries, delivered to Atlanta, is significantly less than the \$1.67 cost of locally produced methanol.

For Chicago, two possible transportation routes exist: via New Orleans and the Mississippi/Illinois Waterway and via New York and the Great Lakes. The cheapest route from Argentina is via New Orleans (14,700 nautical miles round-trip by tanker, then 1,050 miles by barge). This route is used in Table IV-7. The cheapest route from the Persian Gulf (by 0.9

cents per gallon) is via New York (16,070 nautical miles by tanker, then 1,300 miles by barge). This is shown in Table IV-7. For the winter, it should be assumed that traffic would use the Mississippi/Illinois Waterway route, since this route normally is open year round. For the nonwinter route, shown in Table IV-7, the gasoline-equivalent price of M85 in Chicago ranges from \$1.26 to \$1.46, with Saudi Arabia again being the lowest cost source. Factoring in the higher winter transport cost would increase the lower end by 0.5 cent (0.009 times 4 out of 12 months times 1.74). As with Atlanta, locally produced methanol at \$1.65 is more expensive than imports from any of the three countries.

Table IV-7 also presents cost figures for methanol shipped to El Paso. Methanol is assumed to be shipped to Corpus Christi, Texas, then trucked 717 miles at a trucking cost of \$0.19 per gallon. This makes imported methanol more expensive in El Paso than in the other cities examined.† Despite the high trucking costs, however, methanol from Saudi Arabia is less expensive (\$1.55) than methanol produced in El Paso (\$1.64), while methanol imported from Argentina would cost more than locally produced methanol. Methanol from Qatar would cost the same as locally produced methanol.

CONCLUSIONS

The cost comparisons are summarized in Table IV-8. The analysis is based on assumptions that are favorable to the production of methanol from domestic pipeline natural gas. Even with these assumptions, however, it would not be economic to produce methanol from domestic-pipeline natural gas in the year 2000.

In estimating methanol production costs, it is assumed that the plant will generate revenue for at least 15 years. Thus, an investor considering the construction of a methanol plant would wish to project feedstock prices for future years. It is pertinent that EIA projects the wellhead price of natural gas to increase

*U.S. Department of Energy, "Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector; Technical Report Three: Methanol Production and Transportation Costs," November 1989, DOE/PE-0093, pg. 12.

†If a large-scale methanol market were to develop, methanol or M85 could be transported through oil product pipelines at a cost significantly below these trucking costs.

Table IV-8 — Comparison of Cost of Methanol Made From U.S. Pipeline Gas Versus Gasoline and Imported Methanol for the Year 2000
(1989 dollars per gallon of gasoline-equivalent)

City	M85 With Methanol Made From U.S. Pipeline Gas	Gasoline*	M85 With Methanol Made in Foreign Countries**
Atlanta	1.67	1.31	1.31-1.49
Chicago	1.65	1.31	1.26-1.46
El Paso	1.64	1.31	1.55-1.72

*National average retail price from *Annual Energy Outlook 1990*, DOE/EIA, January 1990.

**Based on costs from Saudi Arabia, Qatar, and Argentina.

rapidly beyond the year 2000. The average wellhead price in 1989 dollars is projected to increase from \$3.23 per Mcf in 2000 to \$4.36 in 2005 and \$5.63 in 2010. The use of these higher projected prices would increase the per-gallon feedstock costs significantly and, consequently, raise the projected cost of producing methanol from domestic natural gas.

At the same time, because of the extensive low-cost natural gas reserves available overseas relative to the demand for this gas, the cost of imported methanol is expected to rise at a much slower pace than domestic gas prices. Consequently, methanol produced from domestic gas will be at an increasing price disadvantage relative to imported methanol.

APPENDIX: COST OF PRODUCTION FOR SMALL-SCALE U.S. REMOTE NATURAL-GAS-BASED METHANOL PLANTS

INTRODUCTION

This appendix presents the concepts, design, capital costs, and cost of production for small-scale (50 to 300 short tons per day*) methanol plants. All costs are based on stand-alone plants located in remote sites and have all the provisions necessary for natural gas compression, acid gas removal, water treatment, effluent treatment, electric power generation, and so forth.

A prototype design developed as a basis for estimating costs uses the well-proven steam-methane reforming process. Other technologies, such as combination reforming or heat exchange reformer, are not as economical at the small-scale or have additional complexity that rules out their operation in remote areas.

Capital and production costs are included for three different natural gas compositions: (1) methane content greater than 95 percent; (2) a high-CO₂ content natural gas and (3) a high-N₂ content natural gas.

The costs of production for the small-scale plants are shown as a function of natural gas price and compared against the costs for conventionally designed world-scale plants.

SMALL-SCALE METHANOL PLANT DESIGN CONCEPTS

Methanol Technology Review

A block-flow diagram for the production of methanol from natural gas in small-scale plants is given in Figure A-1. This diagram is consistent with the requirements of small-scale methanol production and reflects a modular approach in construction. Although it does not represent a particular technology, the diagram

has been adapted from information supplied by Hydro-Chem Processing Inc., Holly Springs, Georgia.

The main processing steps are as follows:

- Desulfurization of feedstock.
- Steam reforming.
- Methanol synthesis.
- Methanol purification.

Desulfurization

Sulfur compounds are undesirable components in the natural gas feedstock because they have a harmful effect on the reforming and methanol synthesis catalysts. These compounds are poisons and cause rapid loss of catalyst activity. Hydrogen sulfide is removed by adsorption over zinc-oxide granules. The chemical reaction may be represented in the following way:

Steam Reforming

In the presence of a nickel catalyst, steam is reacted with the natural gas feedstock at elevated temperatures to give a reformed gas consisting of carbon dioxide, carbon monoxide, hydrogen, water, and unconverted methane. The reactions taking place are complex, but the end product is determined by the interaction of the steam-methane reaction (2), and the water-gas shift reaction (3):

Steam and natural gas are mixed in a ratio of 2.8 mols of steam per mol of carbon contained in the natural gas feedstock. The endothermic reforming reaction takes place inside externally-heated vertical tubes located inside a

*5 million to 30 million gallons per year

Figure A-1 — Modular Methanol Block-Flow Diagram

refractory-lined reforming furnace. These tubes are packed with a nickel-based catalyst.

The heat of reaction is supplied by firing fuel in burners located in the furnace. The burners are designed to handle a mixture of natural gas and synthesis loop purge gas (that is, hydrogen). Flue gases produced by the fuel combustion leave the furnace and pass into a refractory-lined duct where the heat content of this stream is recovered.

When natural gas is the feedstock, the resulting synthesis gas is carbon deficient from the point of view of methanol synthesis reaction stoichiometry. If available, carbon dioxide can be used to make up for this carbon deficiency by being added either as supplemental feed to the reformer or directly into the synthesis loop. Carbon dioxide is usually mixed with the reformed gas before the gas is compressed.

Methanol Synthesis

The methanol synthesis reaction is exothermic and equilibrium limited; thus it proceeds more easily at lower temperatures and higher pressures. Methanol is synthesized both from carbon monoxide and carbon dioxide as shown by the following two reactions:

There are several types of reactor designs that can be used in methanol synthesis:

- Quench-type reactor (Imperial Chemical Industries, or ICI).
- Interbed cooling reactor (Kellogg, Haldor-Topsoe).

- Tubular reactor (Lurgi).
- Tube-cooled converter (ICI and others).
- Coiled-tube reactor (Linde).

The most common types are ICI and Lurgi.

Methanol Purification

In addition to water, a number of organic chemicals are synthesized at the same time as methanol and are condensed with the crude methanol. These chemicals are separated from the methanol in the distillation section. The concentration of these impurities is low and consists of dimethyl ether, higher alcohols (ethanol), ketones, and paraffinic hydrocarbons. Small amounts of dissolved gases are also found in the liquid.

There are several alternative schemes for methanol purification. One-, two- and three-column arrangements are available from licensors. Various modes for heat integration and energy savings can be used, but the most common is to use the heat content of the reformed gas to provide a significant portion of the reboiler duties of the columns.

Small-Scale Methanol Concepts

In addition to a low-cost source of natural gas, the small-scale methanol plant would have to satisfy the following criteria:

- Low capital cost.
- Low maintenance.
- Modular design.
- Self sufficiency.
- High automation.
- Minimum liquid effluents.

Capital Cost

Cost and efficiency are interdependent. In the absence of major technological changes, improvements in efficiency are usually accompanied by rising capital costs as extra heat recovery equipment is added. The reforming section of the plant (including synthesis gas cooling and steam rising) represents approxi-

Table A-1 — Capital Cost Breakdown of World-Scale Methanol Plants (Steam-Methane Reforming)

Reforming	48
Compression	14
Methanol Synthesis	29
Distillation	9
Total	100

mately half of the capital investment of modern large-capacity plants, as shown in Table A-1.

In the case of small plant sizes the relative importance of the reforming area capital cost is less, but still strongly affects the economics of methanol production.

Maintenance

A plant designed and built for a lower efficiency level and having a correspondingly lower capital cost, would also have lower maintenance expenditures. Lower maintenance can be obtained by lowering the operating pressure of the steam system, and in general lower pressures in the process are reflected in lower maintenance requirements.

Modular Design

Small-scale plants can be built in small prefabricated sections called modules. Modular plant design increases the degree of compactness and transportability of the methanol unit. The maximum capacity of the modular plant and thus the economy of scale of the plant is not only related to the size of the individual components but also to the physical size of the workshop building it and any limitations in transporting the modules to the producing sites.

Self-Sufficiency

Self-sufficiency is usually required in areas having locked-in natural gas. This is usually achieved by having onsite power generation. It is important to note however, that self-sufficient plant designs vary from plant location to plant location in that product purity requirements dictate different steam usages and, hence, different concepts for energy recovery.

Automation

In the case of small-scale plants producing methanol in areas where unutilized gas is found, a relatively high degree of automation with minimum operating personnel requirements may be desirable. The opposite would be true (that is, low degree of integrated process control) for a small plant located in a developed site such as a petroleum refinery.

Liquid Effluents

Although this would be true in most cases, the disposal of liquid effluents would be particularly troublesome in remote or temporary locations. Therefore liquid effluents, such as fusel oils and process condensate, need to be eliminated or minimized. The fusel oils (that is, higher alcohols) are eliminated when fuel grade methanol is produced as they are not separated but included with the fuel grade product. Process condensate waste is minimized or eliminated if it is recycled to steam generation treatment (degasification) section.

The various aspects of modular plant design as they relate to each major methanol plant section are described below.

Reforming

The relationship between reforming pressure and the overall steam/power system is of primary importance in defining the process flowsheet of a small-scale modular plant. The thermodynamics of the steam-methane reforming reactions are such that the conversion of methane increases as the reformer pressure decreases and as reforming temperature increases. As the reformer pressure increases, higher temperatures are necessary to maintain high-methane conversions, leading to more expensive reformer tubes and heat recovery systems.

It is important to maintain the methane concentration of the reformed gas as low as possible because methane is an inert in the methanol synthesis reaction. The higher the methane content, the higher will be the synthesis loop purge, and consequently, the greater the loss of reactants from the system. In the case of small-scale plants, low methane concentrations can be obtained by operating at reduced pressures. However, lowering the reformer

pressure increases synthesis gas compression requirements.

To obtain a lower overall investment and reduced maintenance costs, small-scale methanol plants with low-pressure natural gas sources may need to operate at lower pressures than modern world-scale plants. However, the actual reformer operating pressure needs to be established by an overall optimization that includes the synthesis pressure and takes into account the cost and availability of natural gas.

Heat Recovery

Since the development of the low-pressure methanol process by ICI in 1966, there have been a number of process modifications having as a principal objective a reduction in the natural gas consumption of the plant. The reduction, in million Btu per short ton of methanol (MMBtu/ST), has been from about 35 MMBtu per short ton in 1966 to about 25 MMBtu per short ton today.

The following key process modifications lead to a major improvement in efficiency:

- Extensive use of air preheat using reformer flue gases.
- Natural gas preheat using reformer flue gas (previously done by a separate fired heater).
- Use of synthesis gas waste heat to provide part of the distillation heat load.
- Recovery of high level heat from the synthesis loop (ICI process).

One consequence of the use of waste heat from synthesis gas in distillation, was a reduction in the amount of steam generation requirements. To provide the same turbine power requirements from the reduced steam flows, the steam pressure was first raised from 600 to about 1,200 pounds per square inch gauge (psig). Henceforth, with the recovery of heat at high temperature by means of boiler feed water preheat, further liberated waste heat from the synthesis gas area led to even lower steam requirements in the distillation area. Today, modern plants have steam systems that operate at pressures in the range from 900 to 1,700 psig depending on energy cost and engineering contractor's design philosophy.

The degree of energy recovery that is economical for a large plant may not be justified in a small-scale modular plant. To reduce the investment of the methanol plant, several design features of the world-scale plant can be eliminated, basically returning to earlier methanol plant design schemes.

Some of the design features that have been reported by major methanol plant design engineering firms (1) and modular plant contractors (4), are as follows:

- Minimization of plant steam generation.
- Elimination of combustion air preheat.
- Maximization of air cooling.
- Elimination of synthesis gas as a source of reboiler heat in methanol distillation.

The above departures from large-scale methanol plant design not only affect plant cost, but also have an important bearing in plant reliability (that is, reduced maintenance).

The energy consumption level of a self-sufficient small-scale methanol plant is expected to be in the range of 33 to 36 MMBtu per short ton depending on the pressure of the natural gas.

Compression

The use of a particular type of compressor for make-up synthesis gas compression is governed by the volumetric inlet suction flow and discharge pressure. Centrifugal compressors have the advantage of reduced cost and maintenance at large capacities, as well as the ability to be coupled directly to high speed turbines. Therefore this type of machine is now in service in most methanol plants.

As capacity is reduced, the centrifugal compressor efficiency falls off rapidly. Thus, below a certain size, centrifugal compressors cannot be used any longer. Changing to reciprocating compression normally means changing from steam turbine to electric motor drives. Although the particular size at which reciprocating compressors are recommended cannot be specified exactly because of vendor availability, the maximum methanol plant capacity at which they can still be used lies somewhere between 150 and 200 STPD.

For the small-scale plant, the reciprocating compressor offers greater advantage because of increased turndown capabilities.

Methanol Synthesis

Synthesis Pressure

As mentioned above, methanol synthesis is favored by high pressures and low temperatures. When the low-pressure methanol synthesis process was first introduced, the operating pressure of the synthesis section was 750 psig. The second-generation plants built by ICI had a synthesis section pressure of 1,500 psig. One of the principal advantages of the higher pressure was that at plant capacities in excess of 1,200 STPD, only one converter was required. A summary of the advantages and disadvantages of higher pressure operation are presented in Table A-2.

For plants with a steam reformer for synthesis gas generation, the optimum methanol synthesis pressure is dependent strongly on natural gas costs and plant capacity and requires a thorough evaluation. Nevertheless, for small-scale plants in the range of 50 to perhaps 200

**Table A-2 — Advantages
and Disadvantages
of High-Pressure Synthesis**

Advantages

- Smaller converter.
- Reduced catalyst volumes.
- Smaller synthesis loop piping.
- Higher carbon conversion (reduced synthesis gas size).
- Reduction of interchanger heat load.

Disadvantages

- Higher compression requirements.
 - Higher design pressure for synthesis loop equipment and piping.
 - Faster catalyst deactivation rates.
-

STPD the optimum pressure may lie closer to 750 psig, rather than the 1,200–1,500 psig range used by world-scale modern plants.

Converter Type

The majority of methanol plants built around the world use low-pressure synthesis technology offered by ICI and Lurgi. The ICI process uses a quench-type reactor which is relatively simple in construction and is employed in many large-capacity plants. The Lurgi process uses a multitubular reactor that is limited to a maximum methanol capacity in the range from 900 to 1,300 STPD.

The tubular reactor offers some advantages over the quench-type for small-scale plants, since it provides good conversions per pass and good temperature control. Temperature control is easily achieved by varying the steam chest pressure, thus restricting temperature excursions during abnormal operating conditions or plant upsets. In the case of a low-efficiency design, the steam pressure generated by the converter could be matched to the reformer steam pressure and result in a lower cost design.

Methanol Distillation

Crude methanol from the synthesis section is refined by distillation. To produce chemical "AA" grade methanol, a two-column scheme is needed. This scheme is usually increased to three distillation columns in energy-saving systems. Where specifications are not strict, as in the case of "A" grade methanol or fuel methanol production only, one column is needed and energy consumption is reduced from about 3.3 to about 2.0 MMBtu per short ton.

The production of fuel methanol in small-scale modular plants presents a number of cost-reduction synergies, since the lower steam requirements allow the use of low-pressure steam as the sole source of heat for distillation. This eliminates the need for complex heat recovery schemes such as those used in much larger plants.

PROTOTYPE DESIGN

Design Bases

General

The prototype design presented here is not intended to be a fully optimized case; however, all features that would lead to a reliable and low-cost design have been incorporated. Among the key features are the following:

- Conventional steam-reforming technology.
- Production of fuel-grade methanol.
- Elimination of combustion air preheat in the reforming section.
- Natural gas preheat by the reformer effluent (process) stream.
- Elimination of synthesis gas used for heating in methanol distillation.
- Use of reciprocating compressor as make-up gas compressor.
- Onsite generation of electricity in a central steam turbine.
- Use of electric motors for all major drives.
- High-pressure steam header pressure at 600 psig.
- Lowest possible pressure throughout the process.
- Use of low temperatures in the reformer to limit tube material to HK 40 type alloy.
- Provision for natural gas compression.
- Provision for carbon dioxide removal in high-CO₂ gas cases.
- Minimization of liquid effluents by process condensate recycle.
- Fully automated, unattended-mode operation.
- Modular construction.

Process Design Basis

To account for variations in gas quality, three natural gas feed compositions have been analyzed:

- Base Case Natural Gas Feed.
- High-CO₂ Feed Case.
- High-Nitrogen Feed Case.

Natural gas compositions and flows for a 50-STPD plant are given in Table A-3.

Process design basis for the key sections of the plant are provided in Table A-4.

Process Description

Figure A-2 is a block-flow diagram of the inside battery limits (ISBL) section of the methanol plant. (Not shown in the figure are the natural gas compression and the acid gas removal units.) The offsites and support facilities outside the battery limits (OSBL) consist of the following units:

- Methanol storage (7 days capacity).
- Package steam boiler.
- Demineralized water system.

Table A-3 — Natural Gas Feed Cases

Case	Base	High CO ₂	High Nitrogen
Composition, vol %			
Methane	95.67	66.97	70.00
Ethane	2.43	1.70	—
Propane	0.19	0.13	—
Nitrogen	1.71	1.20	30.00
CO ₂	—	30.00	—
Total	100.00	100.00	100.00
Flow (SCFD)*	1.55	1.77	2.82

* Basis: 50 STPD

SCFD = standard cubic feet per day

- Cooling water system (compressor inter-cooler service only).
- Integrated flare system.
- Process condensate treatment.
- Electrical system.
- General utilities (instrument and utility air system, fire water system, inert gas generator, raw water storage, and so forth).

Figures A-3 and A-4 are process flow diagrams of the plant. Natural gas at about 75 psig is divided into two streams. One stream is used as fuel and sent directly to the reformer. The second stream is compressed in a reciprocating compressor to about 230 psig and preheated to 730°F by cooling the effluent synthesis gas from the reformer. After desulfurization, this natural gas stream and process steam are mixed and preheated to 900°F in the convection section of the reformer before entering the reformer tubes.

The reformer effluent gas leaves the radiant section of the reformer at about 1,540°F and 150 psia and is cooled by generating high-pressure steam, preheating natural gas, preheating boiler feed water (BFW), and preheating vacuum condensate from the main turbine. Final cooling to 120°F takes place by air and cooling water.

The flue gases leaving the radiant section of the reformer are cooled by generating and superheating high-pressure steam (600 psig, 750°F), preheating reformer feed, and preheating BFW. The temperature of the flue gas leaving the duct is about 400°F.

After cooling, the synthesis gas from the reforming unit is combined with CO₂ (High CO₂ Feed Case only) and fed to the make-up synthesis gas compressor. After two-stage compression from 140 pounds per square inch absolute (psia) to 760 psia, the gas is sent to the methanol synthesis loop.

Both high-pressure steam generated in the reforming unit and steam generated at the synthesis loop are superheated in the convection section of the reformer. The high pressure steam from the reformer and supplemental superheated steam from a package boiler is

Table A-4 — Small-Scale Methanol Process Design Basis

Acid Gas Removal (If required)

Type	Amine
Amine concentration (weight)	33%
Stripper reboiler temperature	245°F
Stripper overhead pressure	25 psia
Absorber pressure	260 psia

Desulfurization

Catalyst	Zinc oxide
Natural gas inlet temperature	730°F

Reforming

Reformer type	Vertical (shaft)
Process exit temperature	1,540°F
Radiant outlet temperature	1,800°F
Mixed feed preheat temperature	900°F
Flue gas exit temperature	400°F
Approach to steam-methane equilibrium	50°F
Approach to water-gas shift equilibrium	0°F
Process exit pressure	150 psia
Steam to carbon molar ratio	2.8
Effluent methane concentration	3.3 vol.%

Methanol Synthesis

Methanol carbon selectivity	98.8%
Nominal operating pressure	750 psia
Reactor effluent temperature	482°F
Approach to methanol synthesis equilibrium	18°F
Approach to water-gas shift equilibrium	0°F
Reactor inlet temperature	450°F
Final condensation temperature	140°F
Steam chest pressure	600 psig
Recycle-to-feed ratio (molar)	7.0:1.0

Methanol Distillation

Condenser type	Partial
Operating pressure	35 psia
Reflux ratio	160:1
Number of trays	60
Water concentration in product:	1,000 ppm

Figure A-2 — Modular Methanol Block-Flow Diagram

used to drive the turbogenerator. The process steam is extracted from this turbine at a pressure of 250 psig to provide steam for the reformer and various steam turbines. The remaining high-pressure steam passes through the condensing stage of this turbine to satisfy its power requirements.

Depending on the low-pressure steam (50 psig) process requirements, the medium pressure 250 psig steam is used to drive the following turbines:

- Forced draft fan.
- Induced draft fan.
- BFW pumps.
- Deep well pumps.

Make-up synthesis gas from the synthesis gas compressor and gas from the recycle compres-

sor are preheated to 450°F by reactor effluent gas and fed to the top of the methanol reactor. The heat released during the exothermic reactions is transferred directly to boiling water around the tubes to generate high-pressure steam at about 600 psig.

The reactor outlet gas leaves the reactor at 500°F and is cooled by reactor inlet gas and by an air-cooled unit to 140°F.

Crude methanol from the V/L separator is first flashed at about 50 psig and then purified to fuel-grade in a single column system. Purge gas from the synthesis loop and flashed gas are sent to the reformer to be used as fuel.

Process Performance

Power balances for the three cases analyzed are presented in Table A-5. Compression

Figure A-3 — Reforming and Steam Generation—Process Flow Diagram

requirements for the High Nitrogen Case are approximately 40 percent higher than the Base Case due to the presence of nitrogen. The High CO₂ Case has slightly lower compression requirements due to its higher efficiency in converting natural gas.

Fuel balances for the three cases are given in Table A-6. Overall fuel consumption of the Base Case and the High CO₂ Case are almost identical. Even though the latter case requires a larger amount of package boiler fuel, this is compensated for by its higher methanol synthesis conversion efficiency.

The rather high energy consumption level (36 to about 41 MMBtu per short ton) calculated is consistent with the extent of heat recovery and the requirement for natural gas compression and on-site power generation. If low-priced electricity would be available, the energy consumption level of the plant could be reduced accordingly.

CAPITAL COSTS

Basis

General

The expected level of accuracy of the present estimates is ± 30 percent. Actual plant construction data or quotations from vendors for specific units or process equipment were used whenever possible. For example, for some key units such as the reformer, hydrogen plant construction data were used to confirm some vendor data.

The capital cost data reflect the high quality level used in the petrochemical industry and they conform to the latest codes and specifications of modern plant designs.

Investment Costs

Total erected plant costs were determined for a range of capacities. These costs include the

Figure A-4 — Methanol Synthesis and Distillation—Process Flow Diagram

direct costs, indirect costs, construction overhead, engineering, and contingency. These costs are given in first quarter 1990 constant dollars. The investment costs were derived by using 1990 vendor quotes for equipment, prevailing freight rates, current labor costs, and so forth. The aggregated cost is called a First-Quarter-1990 constant dollar cost.

Direct Field Costs. These include costs of equipment and materials and their installation costs in a modular construction setup. These costs were determined for both the actual processing facilities (ISBL) and support facilities (OSBL). Major direct cost components include:

Major equipment. These include pumps, heat exchangers, vessels, furnaces, reactors, and so forth. Major process equipment was sized and priced based on budget quotes from vendors, in-house pricing data, or both.

Bulk materials. These include piping, instrumentation, skid units, and so forth.

Direct labor. Direct labor is labor involved in the installation of equipment and materials.

Indirect Field Costs. These costs include construction overhead and engineering and are lower than for grassroots facilities, because several plants are built according to a common standard and engineering modifications are minimal.

Construction Overhead. This cost includes the contractor indirects—unallocated labor, nonmanual labor, temporary facilities, construction equipment, and supplies. Contractor indirects are correlated as a percentage of direct labor and are typical of modular construction.

Engineering. This cost represents costs incurred by the contractor or licensor(s) for engineering, procurement, and fees.

Contingency. Contingency is added to the estimate to cover scope omission, inaccurate cost data, construction problems (such as

Table A-5 — Power Balance: 50 STPD

Case	Base Case		High CO ₂		High Nitrogen	
	bhp	kWh ¹	bhp	kWh ¹	bhp	kWh ¹
Process						
Natural Gas Compressor	150	118	160	126	280	220
CO ₂ Compressor	—	—	48	38	—	—
F.D. Fan	20	16	16	13	26	20
I.D. Fan	52	41	42	33	67	53
BFW Pump	28	22	22	18	50	39
Synthesis Gas Cooler Fan	7	5	6	4	11	9
Synthesis Gas Compressor	760	597	642	504	1,070	840
Recycle Compressor	220	173	176	139	257	202
Methanol Synthesis Effluent Cooler Fan	7	5	6	4	9	7
Distillation Column Reflux Pump	4	3	3	3	4	3
Distillation Column Bottoms Pump	4	3	3	3	4	3
Distillation Condenser Fan	5	4	4	3	5	4
Surface Condenser Fan	12	9	10	8	14	11
Acid Gas Removal	0	0	8	6	0	0
Offsites						
Instrument Air Compressor	16	13	16	16	16	13
Cooling Water Pump	10	8	10	10	10	8
Product Transfer Pump	4	3	4	3	4	3
Day Tank Transfer Pump	3	2	3	2	3	2
Crude Methanol Transfer Pump	1	1	1	1	1	1
Deep Well Pumps	40	31	40	31	40	31
Demineralized Water Pump	3	2	3	2	3	2
Other	20	16	20	16	20	16
Total Power Required		1,072		981		1,487
Power Generated						
Expanding 600 psig, 750°F steam:						
To 250 psig Header		458		469		590
Condensing @ 4.5" Hg		596		394		892
Expanding 250 psig, 580°F steam:						
To 50 psig Header		50		150		50
Total Power Generated, kW		1,104		1,013		1,532
Power Margin		32		32		45

¹Power Factor = 0.95
bhp = brake horsepower
kWh = kilowatt-hour

Table A-6 — Fuel Balance: 50 STPD

Case	Base Case	High CO ₂	High Nitrogen
Reformer Balance, MMBtu/hr			
Reforming Duty	19.00	15.24	24.38
Mixed Heat Preheat	2.27	1.82	2.50
Steam Superheat	3.42	2.99	4.73
Steam Generation	4.38	3.98	7.41
BFW Preheat	3.12	2.74	4.33
Total Reformer Absorbed Duty	32.19	26.77	43.35
Reformer Fuel Balance, MMBtu/hr			
Process Fuel Gas	28.16	14.23	46.71
Natural Gas Fuel	6.52	14.47	0.00
Net Fuel Fired	34.68	28.70	46.71
Fuel Consumption, MMBtu/hr			
Reformer Natural Gas Fuel	6.52	14.47	0.00
Package Boiler Fuel (High-pressure Steam)	2.73	6.06	1.40
Natural Gas Feed	58.97	47.40	75.27
Total Feed plus Fuel (LHV), MMBtu/hr	68.22	67.94	76.67
Total Feed plus Fuel (HHV), MMBtu/hr	75.63	75.32	85.00
Specific Energy Consumption (HHV)			
MMBtu/Short Ton	36.30	36.15	40.80
MM Kcal/Metric Ton	10.08	10.04	11.33
GJoule/Metric Ton	37.93	37.77	42.63
MMBtu/Gal	0.1198	0.1193	0.1346

difficulties in transportation of the modules to the site), schedule changes due to late deliveries by vendors, and unforeseen permitting problems.

Owner costs are not included in the estimates. These costs typically include environmental review, land and right-of-way acquisitions, project insurance, and company personnel performing design, construction overview, and project management. Owner costs could also include startup and operator training.

Capital Cost Estimates

Tables A-7 through A-12 present capital cost estimates on a modular construction basis for

Table A-7 — Construction Costs for Modular Methanol Plant: Base Case Natural Gas Feed (million 1990 dollars)

Capacity, STPD MMGal/Year	50 5.0	100 10.0	200 20.0	300 30.0
ISBL				
Natural Gas Reforming ¹	1.10	1.90	3.50	5.00
Gas Compression ²	0.80	1.20	1.90	2.50
Methanol Synthesis	1.90	2.60	4.00	5.30
Distillation	0.70	1.00	1.50	2.00
Subtotal Direct Costs	4.50	6.70	10.90	14.80
Construction Overhead	1.80	2.50	3.70	3.70
Engineering	2.00	2.00	2.50	3.00
Subtotal Indirect Costs	3.80	4.50	6.20	6.70
Bare Plant Cost	8.30	11.20	17.10	21.50
Contingencies	1.30	1.70	2.60	3.20
Subtotal ISBL	9.60	12.90	19.70	24.70
OSBL	3.30	4.20	6.40	7.60
Total Erected Plant Cost	12.90	17.10	26.10	32.30
Specific Investment, \$/Annual Gal	2.58	1.71	1.31	1.08

¹Maximum Reforming Train size = 150 STPD

²Maximum Capacity for Reciprocating Compressors = 200 STPD

several capacities for the three natural gas feed cases evaluated. Data are provided for ISBL and OSBL. For comparison purposes, Table A-13 presents capital cost estimates for conventional construction costs. The latter costs include more extensive support facilities, and correspond to plants designed for a higher energy efficiency.

Figure A-5 illustrates the variation of capital cost in dollars per annual gallon for both modular type construction and conventional onsite type construction. In the case of modular plants, the maximum capacity at which the modular concept is valid is probably about 200 STPD. The shaded band shows both the extent of support facilities needed and the level of uncertainty of the estimate at capacities larger than 200 STPD.

The economies of scale for the modular plants are strongest in the range from 50 to 150

**Table A-8 — Construction Costs
for Offsites and Support Facilities
for Modular Methanol Plant:
Base Case Natural Gas Feed
(million 1990 dollars)**

Capacity, STPD MMGal/Year	50 5.0	100 10.0	200 20.0	300 30.0
ISBL	9.60	12.90	19.70	24.70
OSBL				
Methanol Storage	0.10	0.14	0.20	0.25
Package Steam Boiler Demineralized	0.30	0.50	0.90	1.20
Water System	0.06	0.08	0.10	0.12
Cooling Water System	0.10	0.14	0.20	0.25
Flare System and Interconnecting				
Piping	0.30	0.42	0.60	0.74
Wastewater Treatment	0.15	0.21	0.30	0.37
Electrical System	0.13	0.25	0.50	0.75
General Utilities	0.60	0.86	1.30	1.66
Integrated Control Building and Warehouse	0.60	0.60	0.80	0.80
Site Development	1.00	1.00	1.50	1.50
Total OSBL	3.34	4.20	6.40	7.64

STPD. At higher capacities, equipment duplication, as in the case of the reformer convection section, starts to impact negatively on the plant cost. Reciprocating compressors are thought to be still applicable up to 200 STPD, but this depends on the availability of equipment. At capacities higher than 300 STPD, the use of the vertical cylindrical reformer is questionable and box-type construction is probably preferable.

Investment costs for plants with capacities under 50 STPD are questionable using the present design basis.

COSTS OF PRODUCTION

Costs of production are those costs incurred to operate the methanol facility. These include utility costs, such as electric power and water; operating labor and supplies, such as catalyst and chemicals; maintenance materials and supplies; and taxes, insurance, and corporate

**Table A-9 — Construction Costs
for Modular Methanol Plant:
High-CO₂ Natural Gas Feed
(million 1990 dollars)**

Capacity, STPD MMGal/Year	50 5.0	100 10.0	200 20.0	300 30.0
ISBL				
Acid Gas Removal	0.50	0.80	1.20	1.60
Natural Gas Reforming ¹	0.90	1.60	3.10	4.40
Gas Compression ²	0.80	1.20	1.90	2.50
Methanol Synthesis	1.60	2.30	3.50	4.60
Distillation	0.70	1.00	1.50	2.00
Subtotal Direct Costs	4.50	6.90	11.20	15.10
Construction Overhead	2.00	2.70	3.90	3.90
Engineering	2.20	2.20	2.80	3.40
Subtotal Indirect Costs	4.20	4.90	6.70	7.30
Bare Plant Cost	8.70	11.80	17.90	22.40
Contingencies	1.40	1.80	2.70	3.40
Subtotal ISBL	10.10	13.60	20.60	25.80
OSBL	3.30	4.20	6.40	7.60
Total Erected Plant Cost	13.40	17.80	27.00	33.40
Specific Investment, \$/Annual Gal	2.68	1.78	1.35	1.11

¹Maximum Reforming Train size = 150 STPD

²Maximum Capacity for Reciprocating Compressors = 200 STPD

overhead. Some operating costs such as taxes and insurance are fixed, while others vary with the annual production rate.

Tables A-14 through A-16 are cost-of-production summaries for the modular design capacities studied for the three natural gas feed cases. Table A-17 presents costs of production for conventional construction methods. Tables A-18 and A-19 present the bases used in developing production costs for modular plants and conventional construction respectively.

Figure A-6 illustrates the variation in cost of production as a function of natural gas price for both modular and grassroots construction.

**Table A-10 — Construction Costs
for Offsites and Support Facilities
for Modular Methanol Plant:
High-CO₂ Natural Gas Feed
(million 1990 dollars)**

Capacity, STPD MMGal/Year	50 5.0	100 10.0	200 20.0	300 30.0
ISBL	10.10	13.60	20.60	25.80
OSBL				
Methanol Storage	0.10	0.14	0.20	0.25
Package Steam Boiler	0.30	0.50	0.90	1.20
Demineralized Water				
System	0.06	0.08	0.10	0.12
Cooling Water System	0.10	0.14	0.20	0.25
Flare System and				
Interconnecting				
Piping	0.30	0.42	0.60	0.74
Wastewater Treatment	0.15	0.21	0.30	0.37
Electrical System	0.13	0.25	0.50	0.75
General Utilities	0.60	0.86	1.30	1.66
Integrated Control				
Building and				
Warehouse	0.60	0.60	0.80	0.80
Site Development	1.00	1.00	1.50	1.50
Total OSBL	3.34	4.20	6.40	7.64

**Table A-12 — Construction Costs
for Offsites and Support Facilities
for Modular Methanol Plant:
High-Nitrogen Natural Gas
(million 1990 dollars)**

Capacity, STPD MMGal/Year	50 5.0	100 10.0	200 20.0	300 30.0
ISBL	10.50	14.40	21.90	28.00
OSBL				
Methanol Storage	0.10	0.14	0.20	0.25
Package Steam Boiler	0.30	0.53	0.90	1.23
Demineralized				
Water System	0.06	0.08	0.10	0.12
Cooling Water System	0.13	0.18	0.25	0.31
Flare System and				
Interconnecting				
Piping	0.35	0.50	0.70	0.86
Wastewater Treatment	0.15	0.21	0.30	0.37
Electrical System	0.18	0.35	0.70	1.10
General Utilities	0.57	0.86	1.30	1.66
Integrated Control				
Building and				
Warehouse	0.60	0.60	0.80	0.80
Site Development	1.00	1.00	1.50	1.50
Total OSBL	3.44	4.45	6.75	8.20

**Table A-11 — Construction Costs
for Modular Methanol Plant:
High-Nitrogen Natural Gas
(million 1990 dollars)**

Capacity, STPD MMGal/Year	50 5.0	100 10.0	200 20.0	300 30.0
ISBL				
Natural Gas Reforming ¹	1.50	2.60	4.60	6.60
Gas Compression ²	1.10	1.60	2.50	3.40
Methanol Synthesis	2.00	2.80	4.20	5.60
Distillation	0.70	1.00	1.50	2.00
Subtotal Direct	5.30	8.00	12.80	17.60
Costs				
Construction Overhead	1.80	2.50	3.70	3.70
Engineering	2.00	2.00	2.50	3.00
Subtotal Indirect	3.80	4.50	6.20	6.70
Costs				
Bare Plant Cost	9.10	12.50	19.00	24.30
Contingencies	1.40	1.90	2.90	3.70
Subtotal ISBL	10.50	14.40	21.90	28.00
OSBL	3.40	4.50	6.80	8.20
Total Erected Plant				
Cost	13.90	18.90	28.70	36.20
Specific Investment,				
\$/Annual Gal	2.78	1.89	1.44	1.21

¹Maximum Reforming Train size = 150 STPD

²Maximum Capacity for Reciprocating Compressors = 200 STPD

**Table A-13 — Construction Costs for Conventional Methanol Plant:
Base Case Natural Gas Feed
(million 1990 dollars)**

Capacity, STPD MMGal/Year	100 10	200 20	300 30	500 50	2,500 250
Section					
Natural Gas Reforming	4.6	6.8	8.7	12.0	51.2
Gas Compression	1.5	2.3	3.0	4.2	15.3
Methanol Synthesis	3.5	5.3	6.8	9.2	30.9
Distillation	1.3	1.9	2.4	3.2	10.0
Subtotal Direct Costs	10.9	16.3	20.8	28.6	107.4
Construction Overhead	5.2	7.3	8.8	11.4	30.1
Engineering	7.5	7.5	5.5	7.5	10.0
Subtotal Indirect Costs	12.7	14.8	14.3	18.9	40.1
Bare Plant Cost	23.6	31.1	35.1	47.5	147.5
Contingencies	3.5	4.8	5.3	7.4	22.2
Subtotal ISBL	27.1	35.9	40.4	54.9	169.7
OSBL	8.6	13.4	16.3	23.9	66.6
Total Erected Plant Cost	35.7	49.3	56.7	78.8	236.3
Specific Investment, \$/Annual Gal	2.71	1.80	1.35	1.10	0.68

Figure A-5 — Methanol Plant Construction Cost—Steam-Methane Reforming

**Table A-14 — Modular Plant Costs of Production:
Fuel-Grade Methanol, Base Case Natural Gas Feed
(330 days/year)**

		Plant Capacity (STPD)							
		50		100		200		300	
MMGal/Year		5.0		10.0		20.0		30.0	
Capital Costs, \$ MM									
Battery Limits		9.60		12.90		19.70		24.80	
Offsites		3.30		4.20		6.40		7.60	
Total Fixed Investment		12.90		17.10		26.10		32.40	
Working Capital		0.80		1.10		1.80		2.60	
Total Capital Requirements		13.70		18.20		27.90		35.00	
		Factor	Prices	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y
Variable Costs									
Natural Gas Consumption, MMBtu/Gal		0.1198							
Natural Gas Unit Cost, \$/MMBtu			3.00						
Natural Gas Cost, \$/Gal				0.359	1.797	0.359	3.594	0.359	7.188
Utilities									
Water consumption, Gal/Gal		0.9000							
Water Unit Cost, M\$/Gal			.10						
Water Cost, \$/Gal				0.001	0.005	0.001	0.009	0.001	0.018
Catalyst and Chemicals, \$/Gal				0.020	0.100	0.020	0.200	0.020	0.400
Total Variable Costs				0.380	1.902	0.380	3.803	0.380	7.606
Fixed Costs									
Maintenance, % ISBL		4.0		0.077	0.384	0.052	0.516	0.039	0.788
Operators, men/day		4							
Annual Labor Cost, \$/year			30.000						
Direct Labor				0.024	0.120	0.012	0.120	0.006	0.120
Direct Overhead, 40% of Direct Labor				0.010	0.048	0.005	0.048	0.002	0.048
Insurance, Property Tax, 1.5% TFI				0.039	0.194	0.026	0.257	0.020	0.392
General Overhead				0.008	0.040	0.004	0.040	0.002	0.040
Total Fixed Costs				0.157	0.786	0.098	0.981	0.069	1.388
Capital Charge Rate ¹		0.1800		0.464	2.322	0.308	3.078	0.235	4.698
Total Cost FOB Plant				1.002	5.009	0.786	7.862	0.685	13.692

Notes: 1 Q 1990 U.S. \$
HHV = 1,015 Btu/SCF

¹Percentage on Total Capital Requirements approximately equal to a 10% DCF

**Table A-15 — Modular Plant Costs of Production:
Fuel-Grade Methanol, High-CO₂ Feed**

	Plant Capacity (STPD)									
			50	100		200		300		
MMGal/Year			5.0	10.0		20.0		30.0		
Capital Costs, \$ MM										
Battery Limits			10.10	13.60		20.60		25.80		
Offsites			3.30	4.20		6.40		7.60		
Total Fixed Investment			13.40	17.80		27.00		33.40		
Working Capital			0.80	1.10		1.80		2.60		
Total Capital Requirements			14.20	18.90		28.80		36.00		
	Factor	Prices	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y
Variable Costs										
Natural Gas Consumption, MMBtu/Gal	0.1193									
Natural Gas Unit Cost, \$/MMBtu		3.00								
Natural Gas Cost, M\$/Gal			0.358	1.790	0.358	3.579	0.358	7.158	0.358	10.737
Utilities										
WaterCconsumption, Gal/Gal	0.9000									
Water Unit Cost, M\$/Gal		.10								
Water Cost, \$/Gal			0.001	0.005	0.001	0.009	0.001	0.018	0.001	0.027
Catalyst and Chemicals, \$/Gal			0.020	0.100	0.020	0.200	0.020	0.400	0.020	0.600
Total Variable Costs			0.379	1.894	0.379	3.788	0.379	7.576	0.379	11.364
Fixed Costs										
Maintenance, % ISBL	4.0		0.081	0.404	0.054	0.544	0.041	0.824	0.034	1.032
Operators, men/day	4									
Annual Labor Cost, \$/year		30.000								
Direct Labor			0.024	0.120	0.012	0.120	0.006	0.120	0.004	0.120
Direct Overhead, 40% of Direct Labor			0.010	0.048	0.005	0.048	0.002	0.048	0.002	0.048
Insurance, Property Tax, 1.5% TFI			0.040	0.201	0.027	0.267	0.020	0.405	0.017	0.501
General Overhead			0.008	0.040	0.004	0.040	0.002	0.040	0.001	0.040
Total Fixed Costs			0.163	0.813	0.102	1.019	0.072	1.437	0.058	1.741
Capital Charge Rate ¹	0.2000		0.536	2.680	0.356	3.560	0.270	5.400	0.223	6.680
Total Cost FOB Plant			1.077	5.387	0.837	8.367	0.721	14.413	0.660	19.785

Notes: 1 Q 1990 U.S. \$
HHV = 715 Btu/SCF

¹Percentage on Total Capital Requirements approximately equal to a 10% DCF

**Table A-16 — Modular Plant Costs of Production:
Fuel-Grade Methanol, High-Nitrogen Feed**

	Plant Capacity (STPD)			
	50	100	200	300
MMGal/Year	5.0	10.0	20.0	30.0
Capital Costs, \$ MM				
Battery Limits	10.50	14.40	21.90	28.00
Offsites	3.40	4.50	6.80	8.20
Total Fixed Investment	13.90	18.90	28.7	36.20
Working Capital	0.80	1.20	2.00	2.70
Total Capital Requirements	14.70	20.10	30.70	38.90

	Factor	Prices	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y
Variable Costs										
Natural Gas Consumption, MMBtu/Gal	0.1346									
Natural Gas Unit Cost, \$/MMBtu		3.00								
Natural Gas Cost, \$/Gal			0.404	2.019	0.404	4.038	0.404	8.076	0.404	12.114
Utilities										
Water Consumption, Gal/Gal	0.9000									
Water Unit Cost, M\$/Gal		.10								
Water Cost, \$/Gal			0.001	0.005	0.001	0.009	0.001	0.018	0.001	0.027
Catalyst and Chemicals, \$/Gal			0.020	0.100	0.020	0.200	0.020	0.400	0.020	0.600
Total Variable Costs			0.425	2.124	0.425	4.247	0.425	8.494	0.425	12.741
Fixed Costs										
Maintenance, % ISBL	4.0		0.084	0.420	0.058	0.576	0.044	0.876	0.037	1.120
Operators, men/day	4									
Annual Labor Cost, \$/year		30.000								
Direct Labor			0.024	0.120	0.012	0.120	0.006	0.120	0.004	0.120
Direct Overhead, 40% of Direct Labor			0.010	0.048	0.005	0.048	0.002	0.048	0.002	0.048
Insurance, Property Tax, 1.5% TFI			0.042	0.209	0.028	0.284	0.022	0.431	0.018	0.543
General Overhead			0.012	0.060	0.006	0.060	0.006	0.120	0.004	0.120
Total Fixed Costs			0.171	0.857	0.109	1.088	0.080	1.595	0.065	1.951
Capital Charge Rate ¹	0.1800		0.500	2.502	0.340	3.402	0.258	5.166	0.217	6.516
Total Cost FOB Plant			1.096	5.482	0.874	8.737	0.763	15.255	0.707	21.208

Notes: 1 Q 1990 U.S. \$
HHV = 710 Btu/SCF

¹Percentage on Total Capital Requirements approximately equal to a 10% DCF

**Table A-17 — Conventional Plant Costs of Production:
Fuel-Grade Methanol, Natural Gas Feed**

	Plant Capacity (STPD)									
			200	300		500		2,500		
MMGal/Year			20.0	30.0		50.0		250.0		
Capital Costs, \$ MM										
Battery Limits			35.9	40.4		54.9		169.7		
Offsites			13.4	16.3		23.9		66.6		
Total Fixed Investment			49.3	56.7		78.8		236.3		
Working Capital			3.4	4.0		5.5		18.2		
Total Capital Requirements			52.7	60.7		84.3		254.5		
	Factor	Prices	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y	\$/Gal	MM\$/Y
Variable Costs										
Natural Gas Consumption, MMBtu/Gal	0.0980									
Natural Gas Unit Cost, \$/MMBtu		3.00								
Natural Gas Cost, \$/Gal			0.294	5.880	0.294	8.820	0.294	14.700	0.294	73.500
Utilities										
Water Consumption, Gal/Gal	1.8000									
Water Unit Cost, M\$/Gal		.10								
Water Cost, \$/Gal			0.002	0.036	0.002	0.054	0.002	0.090	0.002	0.450
Catalyst and Chemicals, \$/Gal			0.020	0.400	0.020	0.600	0.020	1.000	0.020	5.000
Total Variable Costs			0.316	6.316	0.316	9.474	0.316	15.790	0.316	78.950
Fixed Costs										
Maintenance, % ISBL	4.0		0.108	2.154	0.081	2.424	0.066	3.294	0.041	10.182
Operators, men/day	31									
Annual Labor Cost, \$/year		30.000								
Direct Labor			0.047	0.930	0.031	0.930	0.019	0.930	0.004	0.930
Direct Overhead, 40% of Direct Labor			0.019	0.372	0.012	0.372	0.007	0.372	0.001	0.372
Insurance, Property Tax, 1.5% TFI			0.037	0.740	0.028	0.851	0.024	1.182	0.014	3.545
General Overhead, 65% labor plus maint.			0.100	2.005	0.073	2.180	0.055	2.746	0.029	7.223
Total Fixed Costs			0.310	6.200	0.225	6.757	0.170	8.524	0.089	22.251
Capital Charge Rate ¹	0.2000		0.493	9.860	0.378	11.340	0.315	15.760	0.189	47.260
Total Cost FOB Plant			1.119	22.376	0.919	27.571	0.801	40.074	0.594	148.461

Notes: 1 Q 1990 U.S. \$
HHV = 1,015 Btu/SCF

¹Percentage on Total Capital Requirements approximately equal to a 10% DCF

Table A-18 — Bases for Methanol Production Costs—Modular Plant Concept

- First quarter 1990.
 - Operating factor: 90 percent, 330 days per year.
 - Direct overhead at 40 percent of labor and supervision.
 - General plant overhead at \$40,000 per year.
 - Maintenance at 4 percent of ISBL cost.
 - Insurance and property taxes at 1.5 percent of total fixed investment.
 - Working capital is calculated as the sum of the following four items:
 1. **Feedstock Inventory**—One month's supply of raw materials valued at delivery prices.
 2. **Finished Product Inventory**—Half a month's supply of principal product valued at gross cost of production. This is based on liquid product storage and excludes items that are not normally stored.
 3. **Accounts Receivable**—One month's gross cost of production.
 4. **Cash**—One week's out-of-pocket expenses estimated at gross cost of production less depreciation.
- Less a fifth item:
5. **Accounts Payable**—One month's gross cost of production
- Capital charges at 18 percent of Total Fixed Investment. This charge is approximately equivalent to a 10-percent DCF rate of return with the following parameters:
 - Two years for construction with expenditures of 50 percent in the first year and 50 percent in the second year.
 - Ten years of operation.
 - Income tax rate of 37 percent.
 - No sales expenses.
 - Capacity buildup of 100 percent of nameplate capacity in the first year of operation.
 - Depreciation at 5 years straight line for battery limits investment and 15 years straight line for outside battery limits investment.
-

Table A-19 — Bases for Conventional Methanol Production Costs

- First quarter 1990.
- Operating factor: 90 percent, 330 days per year.
- Direct overhead at 40 percent of labor and supervision.
- General plant overhead at 65 percent of operating costs.
- Maintenance at 6 percent of ISBL costs.
- Insurance and property taxes at 1.5 percent of total fixed investment.
- Working capital is calculated as the sum of the following four items:
 1. **Feedstock Inventory**—One month's supply of raw materials valued at delivered prices. This is also based on liquid or solid product storage and excludes items that are not normally stored.
 2. **Finished Product Inventory**—Half a month's supply of principal product and byproduct and byproduct (if any) valued at gross cost of production. This is also on liquid or solid product storage and excludes items that are not normally stored.
 3. **Accounts Receivable**—One month's gross cost of production.
 4. **Cash**—One week's out-of-pocket expenses estimated at gross cost of production less depreciation.

Less a fifth item:

5. **Accounts Payable**—One month's supply of raw materials at delivered prices.
- Capital charges at 20 percent of Total Fixed Investment. This charge is approximately equivalent to a 10-percent DCF rate of return with the following parameters:
 - Three years for construction with an expenditure of 30 percent in the first year, 50 percent in the second year, and 20 percent in the third year.
 - Fifteen years of operation.
 - Income tax rate of 37 percent.
 - No sales expenses.
 - Capacity buildup of 60 percent of nameplate capacity in the first year, 80 percent the second year, and 100 percent from the third year onward.
 - Depreciation at 5 years straight line for battery limits investment and 15 years straight line for outside battery limits investment.
-

Figure A-6 — Methanol Cost of Production

BIBLIOGRAPHY

1. English, A. and I.A. Forbes. "Methanol Plant Design—Concepts for the 1990's." 1989 World Methanol Conference. Crocco & Associates.
2. Dunster, M. and Islam, M.N. "Review of Methanol Production Processes." Chem E Symposium—Carbon One Chemical Technology, The Institution of Chemical Engineers. London, March 1986.
3. Abbott, P.E.J., M.R. Conduit, and K. Mansfield. "Methanol—A New Process for the 1990's." 1989 World Methanol Conference. Crocco & Associates.
4. Personal Communication. Hydro-Chem Processing Inc. April 1990.