INTERRELATIONSHIP OF PROPOSED GAS-BASED PETROCHEMICAL DEVELOPMENT AND THE ALASKA NATURAL GAS PIPELINE PROJECT

INTERRELATIONSHIP OF PROPOSED GAS-BASED PETROCHEMICAL DEVELOPMENT AND THE ALASKA NATURAL GAS PIPELINE PROJECT

By

Matthew D. Berman
Institute of Social and Economic Research
University of Alaska
707 A Street
Anchorage, Alaska 99501

Prepared for

House Research Agency
Alaska State Legislature

July 1981

INTERRELATIONSHIP OF PROPOSED GAS-BASED PETROCHEMICAL DEVELOPMENT AND THE ALASKA NATURAL GAS PIPELINE PROJECT

Introduction

This paper describes some of the relationships between Alaska Natural Gas Transportation System (ANGTS) and the proposed use of Prudhoe Bay gas liquids for petrochemical feedstock. The report discusses certain burdens that the gas pipeline project might encounter as a result of petrochemicals development, distinguishing between those burdens that might arise because of market competition for limited resources, and those that might arise because of government regulation. The report also outlines measures that the State might take to mitigate the burden that one project might create upon the other without a significant financial impact to either project.

This study has concentrated on the concept advanced by the Dow-Shell group as the basis for Alaska petrochemical development. This concept is similar to the projects analyzed in two state-supported studies, Bonner and Moore (1979) and Zinder (1980).[1] Exxon Chemical Company is also investigating the possible use of Prudhoe Bay natural

---

[1] Bonner & Moore Associates, Inc. Promotion and Development of the Petrochemical Industry in Alaska. November 1, 1979. Zinder Energy Processing, Preliminary Economic Evaluation of NGL-Based Petrochemical Production in Alaska, prepared for Alaska State Legislature, House Research Agency, October 1980.

gas liquids as feedstock for an olefins facility while Arco is studying conversion of Prudhoe Bay methane into methanol. Another report by the Institute of Social and Economic Research (ISER)[2] concludes that if North Slope hydrocarbons are to be processed into petrochemicals within Alaska, it is more likely to be under Exxon (and/or Arco) sponsorship than that of Dow and Shell. Little information exists, however, in the public domain about the Exxon and Arco projects. For this reason, the report relies largely on information provided by Dow and Shell.

Due to time limitations on this study, much information about the parameters of the Dow-Shell project has been obtained from preliminary reports. Similarly, the technical and economic features of ANGTS are still evolving as further engineering tests are being evaluated and as negotiations proceed regarding financial and legal structure. Thus, one must keep in mind that the conclusions of this study are based on the best information available at the time of writing and will need to be adjusted as new information supersedes that from old sources.

The report contains four sections. The first section outlines the general technical relationships between a gas-liquids-based petrochemical development similar to the Dow-Shell proposal and the proposed Alaska gas pipeline project. Next is a section discussing

---

[2] Arlon Tussing and Lois Kramer, Hydrocarbons Processing: Introduction to Petroleum Refining and Petrochemicals for Alaskans, University of Alaska, Institute of Social and Economic Research, August 1981.

the market relationships of the two projects, highlighting areas where the two projects must compete with one another for resources or customers. Third is a section defining the potential impacts of one project on the other that may arise from government regulation, independent of the question of availability of resources and markets. The concluding section outlines some proposed general measures for mitigating the potential adverse impacts described in sections three and four.

Technical Relationships of the Dow-Shell Project to the Proposed Natural Gas Pipeline

The Dow-Shell Group now envisions two ethylene plants, each with a capacity of 1,500 million pounds per year and requiring approximately 45,000 barrels per day of ethane as feedstock. The ethylene plants, of which one would be constructed in "Phase I" of the project and the other delayed until "Phase II" (at least five years later), would be associated with a variety of secondary petrochemical plants. The Dow-Shell Group has proposed extracting the liquids from the natural gas stream prior to gas conditioning, with a gas liquids pipeline constructed from Prudhoe Bay to a petrochemical complex at a tidewater location.

The current Dow-Shell proposal substantially resembles Scenario 1 of the Zinder study, with two important modifications. The Zinder scenario envisioned that the petrochemical industry would be expanded to the level of 3,000 million pounds per year production of ethylene in three phases, rather than in two phases. In addition, the Zinder study was based on the assumption that a quantity of ethane sufficient at least for a 1,000-million-per-year-ethylene plant would be obtained from the natural gas conditioning plant. Natural gas liquids required to expand capacity in the later phases would be extracted downstream from the conditioning plant. The Dow-Shell Group, on the other hand, currently plans to extract all the gas liquids upstream from gas-conditioning, so that liquids extraction is independent of the timing and technology of the gas pipeline project. The material balance proposed for Prudhoe Bay natural gas and gas liquids under the Zinder and the Dow-Shell assumptions are summarized in Table 1.

If the Dow-Shell group proceeds to develop their project as currently proposed, the removal of gas liquids has several implications for the ANGTS project. Most importantly, the sales gas conditioning plant would have to be redesigned. The revised plant design being prepared by the Ralph M. Parsons Company assumes that the gas liquids will not be removed prior to conditioning. In addition, the removal of gas liquids has implications for the design of the gas pipeline, which would most likely be transporting a leaner gas stream. In neither case, however, would the gas pipeline project encounter any major technical problems or significant cost increases.

TABLE 1. MATERIAL BALANCE: SADLEROCHIT GAS AND GAS LIQUIDS

Scenario	ANGTS Gas		Liquids Pipeline		
	MMSCF/day	MMBTU/day[1]	BBL/day		MMBTU/day[1]
			Ethane	Propane Plus	Total Liquids
Zinder Base Case					
Low Field Fuel Requirements	2,044	1,985,129	--	--	--
High Field Fuel Requirements	2,032	1,944,887	--	--	--
Zinder Scenario 1					
One Ethylene[2] Plant	1,999	1,875,863	30,250	127,447	563,740
Two Ethylene[2] Plants	1,941	1,789,640	60,500	128,291	643,556
Three Ethylene[3] Plants	1,502	1,354,572	90,750	128,011	719,931
Dow-Shell					
Phase I[2,4]	(1,970)	(1,832,396)	45,000	120,000	573,300
Phase II[3,5]	(1,502)	(1,354,572)	90,000	120,000	687,400

[1]Lower heating value.

[2]Assumes low field fuel requirements (approximately 20,000 MMBTU/day).

[3]Assumes high field fuel requirements (approximately 350,000 MMBTU/day).

[4]Assumes pipeline gas quantity and characteristics midway between those of the one- and two-ethylene-plant operations of Zinder Scenario 1.

[5]Assumes same pipeline gas as Zinder Scenario 1, three-ethylene-plant operation.

Market Relationships of the Dow-ShellProject to the Proposed Natural Gas Pipeline

The Dow-Shell project competes with the ANGTS project in markets for labor, land, capital, raw materials, and services as well as providing potential competition in markets for final products. The nature and extent of such competition is outlined below for each of the various markets.

Natural Gas and Gas Liquids

The current design of Alaska Natural Gas Transportation System is to move natural gas containing only a limited quantity of gas liquids so as to prevent condensation in the pipeline. However, a significant quantity of ethane, propane, and more complex hydrocarbons would remain in the conditioned gas stream. The energy content of these heavier components is expected to add roughly ten percent to the BTU content of the gas transported through the ANGTS pipeline if the gas liquids are not extracted for use by a petrochemical industry.

The economic feasibility of petrochemical development depends, among other things on the cost of transporting the raw material (ethane) to the tidewater site. The transport cost per BTU of energy delivered through a liquids pipeline, just as for the ANGTS pipeline, is strongly affected by the total quantity of energy available to transport. Thus, the two projects are potentially competing for approximately 200,000 MMBTU per day of natural gas liquids.

Continued development of Prudhoe Bay oil and gas resources will require an increasing amount of energy for such uses as oil lifting and water injection. Conditioning of natural gas and extraction of gas liquids also are projected and add significantly to field fuel requirements. The material balance for Scenario 1 of the Zinder study implies that field fuel requirements will exceed 350,000 MMBTUs per day, including gas conditioning and liquids extraction, by the time the petrochemical industry could be fully developed (such as with Phase II of the Dow-Shell proposal).[3]

Since the wellhead value of North Slope oil is clearly higher per BTU than that of natural gas or gas liquids, it is the latter substances that the producers will most likely prefer to use for field fuel. Thus, the gas pipeline project and the petrochemical project would be competing for the same commodities that the Prudhoe Bay producers own and desire to use for field fuel.

One possibility that has been raised is that the increment in gas and gas liquids production which might allow both projects to run at full capacity may be obtained from increasing the rate of production of gas from the Prudhoe Bay reservoir beyond the rate needed to obtain 2.0 billion cubic feet of conditioned gas per day. While such an increase is technically possible, it would shorten the producing life of the gas reserves. In addition, increasing the rate of gas production from the field may require higher rates of oil production and a

---

[3]Zinder, op. cit., Table 1.

higher gas-oil ratio for producing wells, a change that might have a significant impact on conservation of oil. Because of the potential impact of such measures on ultimate oil recovery, a strategy of increasing the rate of gas sales would likely face regulatory obstacles from the Oil and Gas Conservation Commission.[4]

Fuel-grade methanol on the North Slope could be produced from unprocessed Prudhoe Bay gas (whose CO_2 content materially increases the efficiency of the process). Methanol might be batched or blended with crude oil in the Trans-Alaska Pipeline System (TAPS) or shipped directly from the North Slope in ice-breaking tankers or submarine barges. This concept had been proposed a number of years ago as an alternative to a natural-gas pipeline. This was one of the five transportation options for North Slope gas that the Alaska Natural Gas Transportation Act required the President to consider, in addition to a MacKenzie Valley pipeline, a trans-Alaska pipeline-LNG system, no transportation system, and, of course, the Alaska Highway pipeline. The methanol concept has been advocated at various times by Wentworth Brothers, Davy-McKee, and Westinghouse, and it has recently been examined again by Arco.

Depending on the scale of methanol production from North Slope natural gas, such a project could be seen as a substitute for ANGTS. Even a relatively small methanol conversion plant could compete

---

[4]Confirmed in a telephone conversation with Hoyle Hamilton, Chairman, Alaska Oil and Gas Conservation Commission.

directly with ANGTS for the available gas supplies. Unless the gas pipeline project finally and officially collapses, however, the ability of the gas producers to choose the methanol alternative is limited by the fact that they have already sold their Prudhoe Bay gas reserves to gas company members of the Northwest partnership.

Another option for obtaining additional gas and liquids is from other oil and gas reservoirs in the vicinity of Prudhoe Bay, elsewhere on the Arctic Slope or in the Beaufort Sea. Table 2 shows the most likely estimates of known gas reserves in the Prudhoe Bay area, with rough estimates of potential field production dates. Table 2 confirms that there are indeed significant additional gas reserves on the North Slope. However, absence of a field development infrastructure and the uncertainty about whether gas reserves will need to be reinjected for oil conservation purposes makes it questionable that gas will be available for sale from these other fields for ten years or more.

A possible exception is the Kuparuk River formation, scheduled to begin oil production in 1982. But the small quantity of gas in this reservoir, as shown in Table 2, is not sufficient to affect the supply of available gas for the ANGTS and the gas liquids pipelines. Major new gas discoveries in the Beaufort Sea area are also possible, but again there is little likelihood these undiscovered gas resources will be available for sale during the first ten to fifteen years of the two pipeline projects. One must conclude, then, that the Dow-Shell project and ANGTS may have to compete directly for a portion of natural

TABLE 2. ESTIMATED GAS RESERVES, NORTH SLOPE, ALASKA

Area	Estimated Reserves (Billion Cubic Feet)	Production Status
Prudhoe Bay Lisburne Reservoir (includes Sag Delta and Duck Island areas)	1,900[1]	Could begin production by 1990
Kuparuk River Formation	206[2]	Oil production expected to begin April 1982[2]
Point Thomson area & Flaxman Island area	4,500[1]	Production unlikely before 1995
Total excluding Sadlerochit Reservoir	6,606	
Prudhoe Bay Sadlerochit Reservoir	29,000	Producing oil, reinjection of produced gas
Total	35,606	

[1] "Most likely" estimate.

[2] Hoyle Hamilton, Oil and Gas Conservation Commission, personal communication.

SOURCES: (Except Kuparuk River Formation.) William Van Dyke, "Proven and Probable Oil and Gas Reserves, North Slope, Alaska," State of Alaska, Department of Natural Resources, Division of Minerals and Energy Management, September 25, 1980, Table 2.

gas and gas liquids for at least the first several years of their projected operations.

Product Markets

In general, it is more economical to process light hydrocarbon gases (methane and ethane) into liquid or solid petrochemicals (e.g., methanol, urea, ethylene glycol, polyethylene) near the source than to ship them long distances in the gaseous state for processing "downstream." Some observers have speculated that if shippers on the gas pipeline are able to obtain significant amounts of ethane and propane to include in the gas stream, the gas-liquids-based petrochemical industry in Alberta might be a potential buyer of these components. In this case, the Canadian petrochemical industry would compete indirectly with an Alaskan industry through the mechanics of world markets for ethylene, propylene, and their derivative products.

The undeveloped gas reserves of Alberta are huge, however, and much of this gas is "wet" gas, containing a large volume of NGLs or condensate. Restrictive federal and provincial export policies have depressed prices of light hydrocarbons in Western Canada far below their value on continental or world markets. Thus, it is not likely that North Slope gas or NGL would be price-competitive in Alberta against local supplies. Canadian gas- and gas-liquids-based petrochemicals may emerge as a serious competitor with any potential Alaska production, but this competition would almost certainly rest on low-priced Canadian feedstocks and not on the use of North Slope NGLs.

Competition for world petrochemical markets arising from an Alaskan industry is, therefore, unlikely to affect significantly the downstream marketability of ANGTS gas. In any event, the proportion of ANGTS throughput which would be potentially affected by this kind of competition would be relatively small. The primary product offered for sale from the gas pipeline, natural gas, is not relatively attractive economically as a feedstock for producing olefins and, therefore, does not come into direct competition with the ethylene derivatives that would be the chief product of an NGLs-based petrochemicals project.

Labor Markets

Preliminary estimates for construction employment for the Dow-Shell project indicate an average annual workforce of five-to-six-thousand workers for several years, including workers on the liquids pipeline. Peak employment figures are not available, but based on proposed construction schedules for the proposed Alaska Oil Company refinery in Valdez[5] and the Alaska segment of ANGTS,[6] the peak employment may be more than double that number. This construction workforce requirement is somewhat smaller, but of the same order of magnitude, as that estimated for the Alaska segment of the gas pipeline.

---

[5] Environmental Impact Statement. Alaska Petrochemical Company, Refining and Petrochemical Facility, Valdez, Alaska, December 1979, Appendix Volume II.

[6] Application of Alaskan Northwest Natural Gas Transportation Company for a Final Certificate of Public Convenience and Necessity, Docket No. CP80, U.S. Federal Energy Regulation Commission, Washington, D.C., July 1, 1980.

A summary of regional annual average construction employment for the various projects is provided in Table 3. One must remember that the numbers presented are preliminary estimates and, particularly in the case of Dow-Shell project items, may be amended significantly as feasibility studies progress. However, the overall potential regional picture, as reflected in the table, will likely remain the same. The proposed schedules for construction of the two projects are also, of course, not firm at this time. But if there are no further unanticipated delays and sponsors for both projects are able to proceed, there is a strong possibility that construction of both projects may proceed at the same time.

Table 3 suggests that in this case the annual average construction employment demand could be in excess of 15,000 persons between 1984 and 1987. Depending on construction schedules, the peak work force requirements of the combined projects may be double that number during the summer of 1986 or 1987.

It is apparent that resident Alaska labor markets cannot possibly serve a labor demand of this magnitude. The two projects would be forced to compete aggressively for labor with an increased likelihood that construction delays and cost overruns would result. In addition to the workforce directly involved in construction, the two projects would be competing for suppliers to construction contractors, construction camp caterers, transportation services, and other construction-related services. Similar problems with delays and cost overruns would be likely to be caused by very tight markets.

TABLE 3. CONSTRUCTION MANPOWER REQUIREMENTS OF PROPOSED PROJECTS DEVELOPING NORTH SLOPE HYDROCARBON RESOURCES

Project	Average Annual Construction Employment	Proposed Construction Schedule (Tentative)
North Slope		
Prudhoe Bay Waterflood[1]	800	1982-1984
Gas Conditioning Plant[2]	375 - 725	1984-1987
Natural Gas Liquids Extraction Plant[3]	200	1985-1987
Total, North Slope	1,375 - 1,725	1982-1987
Interior		
ANGTS Pipeline[2]	5,000 - 10,000	1984-1987
Liquids Pipeline[3]	3,000	1985-1987
Methanol Plant[3]	800 - 1,000	1984-1987
Total, Interior	8,800 - 14,000	1984-1987
Southcentral		
Dow-Shell Phase I	1,800 - 2,000	1984-1987
(Alaska Oil Co. Refinery)[4]	1,000 - 2,000	(postponed indefinitely)
Total, Southcentral	2,800 - 4,000	1984-1987
Total, All Projects, Excluding Alaska Oil Co. Refinery	11,975 - 17,725	1982-1987

[1]Final Environmental Impact Statement, Prudhoe Bay Oil Field Waterflood Project, Prudhoe Bay, Alaska, Figure 2.5-16, p. 2-60.

[2]ISER, "Relationship between the Alaska Natural Gas Pipeline and State and Local Government Expenditures," Table 2.

[3]Dow-Shell Group Preliminary Estimates.

[4]Environmental Impact Statement, Alaska Petrochemical Company Refining and Petrochemical Facility, Valdez, Alaska, December 1979, Appendix Volume II, Table 3.6.1-1, p. II-23.

Land and Rights-of-Way

For approximately the first 400 miles from Prudhoe Bay, the gas liquids pipeline and the gas pipeline must travel together through a narrow corridor of federal land. The ANGTS project has been issued a right-of-way across these lands, but in some areas such as Atigun Pass, the conflicts with the Alyeska oil pipeline right-of-way have not yet been resolved. Right-of-way conflicts from an NGL are less than between the other two since NGL is neither heated nor cooled and requires less engineering space.

Nevertheless, the addition of a third pipeline in the same corridor will undoubtedly create space problems in certain areas, particularly Atigun Pass. Since the ANGTS project has the right-of-way preference, the sponsors of the proposed liquids pipeline are clearly at a disadvantage in this regard. If the petrochemical project is to be located at Valdez or on Point Gravina, similar right-of-way conflicts with the existing Alyeska oil pipeline may occur in the stretch between Thompson Pass and Valdez.

Capital Markets

The financial agreement recently negotiated between Northwest and the North Slope producers calls for the producers to provide 30 percent of the equity share of the financing for the gas pipeline--with the Northwest partners to come up with the rest--if the required changes in the authorizing legislation are approved by Congress. As far as internal sources of capital are concerned, there is no competition between ANGTS and the Dow-Shell group. If the producers themselves were to sponsor the petrochemical projects, there would be a serious question of their ability or willingness to furnish equity for both enterprises. Their capacities and interests would differ widely, however. Sohio is in the strongest cash-flow position. However, its share of the natural gas and NGL's is the smallest among the big three North Slope producers, and among them it is the least involved with petrochemicals.

Arco, on the other hand, is a major Prudhoe Bay gas producer, a major chemical producer nationally, and is actively investigating the methanol option. But Arco is now strapped for capital, and there is a serious question how it can finance both its development of the Kuparuk formation and its share of ANGTS. In addition, the fact that Arco is actively considering methanol may, therefore, be an indication that it views methanol as an alternative, rather than a complement, to the gas line.

Exxon is the other major producer. This company probably controls a large share of the indicated, but still unannounced, North Slope gas reserves, and is one of the world's largest petrochemical producers. Exxon is clearly strong enough financially to participate in both the gas pipeline and a petrochemicals venture.

The petrochemical project as well as the gas pipeline will probably require a multibillion dollar debt financing plan. Since the major international investment banks and bond markets would ultimately be the sources of long-term loans for both projects, it is likely that there will be direct competition for external financing. The degree of competition for capital depends upon the degree to which the completion of one project adds to the risk as perceived by investors that the other project might fail. The risk is related to two major factors: (1) the overall effect that competition for natural gas and gas liquids, labor, land, and supplies might have to increase the risk of construction cost overruns and (2) the exposure of those financial institutions that participate in the debt of both projects to risks that might jeopardize the income of both of them. Examples of the second form of risk are an unexpected (but not unprecedented) inability to produce gas in the forecasted volumes, destruction of the gas-conditioning/liquids-extraction plant, or even the failure of TAPS or destruction of the Valdez terminal, which might dictate cessation of gas as well as oil production.

Regulatory Considerations

The proposed petrochemical project and the gas pipeline project face regulation of the price and quantity of raw materials that may be purchased from North Slope fields. In addition, they face federal regulation of pipelines involved in interstate commerce. The Alaska Public Utilities Commission has just inherited regulation of pipeline shipments within Alaska from the Alaska Pipeline Commission, but it is likely to follow patterns set by federal agencies.

Raw Materials

Reservoir production rates of natural gas and associated gas liquids from Alaska's North Slope fields are currently regulated by the Alaska Oil and Gas Conservation Commission. The Conservation Commission regulates all oil and gas production in the state under a broad mandate to "prevent waste." Conservation Order 145, which discussed preliminary field rules for Prudhoe Bay, set the limit on the allowable rate of sale of gas from the Sadlerochit Reservoir at a nominal rate of 2.7 billion cubic feet per day.[7]

The price of natural gas at Prudhoe Bay is also regulated under a price ceiling established in the Natural Gas Policy Act. The ceiling price, which is now just over $2.00 per MMBTU, may increase only as adjusted for inflation, regardless of demand. President Reagan has voiced support for removing regulation of natural gas prices altogether, but this would require Congressional action in the case of Alaska North Slope gas.

FERC will probably attempt to enforce the ceiling price for gas liquids that are blended into the gas stream even if they are subsequently removed from the pipeline for use in a petrochemical facility. However, the ceiling would probably not apply if the liquids are removed prior to sales gas conditioning, as would be the case in the Dow-Shell proposal. The ability to escape price regulation of

---

[7]Alaska Oil and Gas Conservation Commission, Conservation Order 145, June 1, 1977.

purchased feedstock may be an important reason why the Dow-Shell group has proposed to build a separate liquids pipeline from Prudhoe Bay to tidewater.

Federal Pipeline Regulation

The ANGTS pipeline tariff is subject to regulation by the Federal Energy Regulatory Commission (FERC) for the Alaska portion, and by the Canadian National Energy Board (NEB) for the Canadian portion. FERC Orders 31 and 31B outline the concept that FERC is to apply to set the tariff for the proposed pipeline. However, the details of the tariff design have not yet been addressed.

FERC also has regulatory authority over the natural gas liquids (NGL) pipeline if any portion of the liquids is sold in interstate markets without further processing. This is likely in the Dow-Shell proposal since the sponsors propose to export directly propanes and butanes contained in the NGL stream. The Alaska Public Utilities Commission also has recently assumed regulatory jurisdiction over intrastate pipelines from the Alaska Pipeline Commission. The Pipeline Commission had attempted to regulate intrastate oil shipments on the Trans-Alaska Pipeline System (TAPS) to the North Pole refinery.

The uncertainty about who would regulate the proposed liquids pipeline would be of lesser consequence if the petrochemical producers were to own the NGL pipeline. In this case, the viability of petrochemical manufacture would depend on the cost of feedstocks on the

North Slope added to the cost of transporting them to the tidewater location. Regulatory rules would just involve a transfer of funds from one phase of the operation to another. The regulatory impact on the liquids pipeline is more severe under other ownership scenarios. Without some more definite information about the parameters of regulation, however, it is difficult to speculate how regulation of a liquids pipeline would affect the producers' incentive to sell NGL to a petrochemical producer.

FERC regulation of ANGTS is an important factor to the overall financial viability of the gas pipeline project. Under differing rules for the ANGTS tariff and the sales gas price, the proposed petrochemical project has a remarkably different impact. Tables 4 and 5 illustrate the potential impacts of the type of project discussed by the Dow-Shell group on the ANGTS tariff and the value of NGL to the producers as a component of natural gas. While these tables attempt to provide numbers that capture the correct sense of the sensitivity of prices and tariffs under varying assumptions, the actual values expressed in the tables are purely hypothetical. The notes following the tables detail the assumptions used for the analysis.

Table 4 discusses the impact of withdrawal of NGL for a petrochemical industry applying a federal administrative law judge's finding in the TAPS case that the rate base should be based on depreciated original cost. This method implies a very high fixed charge at first, which declines in current dollars to zero after

Table 4. Illustration of Minimum Required Price for Liquids Used as Petrochemical Feedstock: ANGTS Regulated under FERC Rules (Figures in 1981 $/MMBTU)

	Dow Phase I	Dow Phase II	
	1986	1996	2011
Market value of gas, 'lower 48'[1]	$6.00	$7.31	$9.84
ANGTS fixed cost[2]	8.00	2.54	-0-
ANGTS operating cost	1.00	1.00	1.00
Transportation charge	9.00	3.54	1.00
Implied net-back price	- 3.00	3.77	8.84
Cost-plus price[3]	11.00	5.54	3.00
ANGTS rate if NGL removed[4]	9.66	4.65	1.00
Cost-plus price if NGL removed	11.66	6.65	3.00
Extra charge on gas per MMBTU of NGL removed[5]	2.11	2.19	-0-
Minimum required price for NGL, no producer ownership of ANGTS[6]	- 0.89	3.96	8.84
Minimum required price for NGL, 100% producer ownership of ANGTS[7]	5.00	6.31	8.84
Minimum required price for NGL, 30% producer ownership of ANGTS[8]	0.88	4.67	8.84
Minimum required price for NGL, 30% producer ownership of ANGTS and regulated gas price[9]	0.88	2.90	2.00

Table 5. Illustration of Minimum Required Price for Liquids Used as Petrochemical Feedstock: ANGTS Tariff under Replacement Cost Accounting
(Figures in 1981 $/MMBTU)

	Dow Phase I	Dow Phase II	
	1986	1996	2011
Market value of gas, 'lower 48'[1]	$6.00	$7.31	$9.84
ANGTS fixed cost[2]	4.00	4.00	4.00
ANGTS operating cost	1.00	1.00	1.00
Transportation charge	5.00	5.00	5.00
Implied net-back price	1.00	2.31	4.84
ANGTS rate if NGL removed[4]	5.33	6.74	6.74
Extra charge on gas per MMBTU of NGL removed[5]	1.05	3.43	3.43
Minimum required price for NGL, no producer ownership of ANGTS[6]	2.05	5.74	8.27
Minimum required price for NGL, 100% producer ownership of ANGTS[7]	5.00	6.31	8.84
Minimum required price for NGL, 30% producer ownership of ANGTS[8]	2.94	5.91	8.44
Minimum required price for NGL, 30% producer ownership of ANGTS and regulated gas price[9]	2.94	5.61	5.60

TABLE NOTES for TABLES 4 and 5:

[1]Assumes 'lower 48'natural gas prices rise two percent above the rate of inflation.

[2]Assumes pipeline fixed costs under FERC rules start at $7.00 per MMBTU, with a straight-line decline over 25 years in nominal dollars. Inflation assumed to be eight percent per year to convert to 1981 dollars.

[3]Assuming regulated well-head price of $2.00/MMBTU in 1981 dollars.

[4]Transportation charge raised by the fixed cost times the ratio of MMBTU/day under the Zinder base case to MMBTU/day, Dow-Shell scenario (from Table 1, column 2).

[5]Increase in ANGTS rate times the ratio of MMBTU/day of gas to MMBTU/day, NGL, Dow-Shell scenario (ratio of column 2 to column 5, Table 1).

[6]Net-back price plus extra ANGTS charge.

[7]Market value of gas, 'lower 48' less operating cost.

[8]Seventy percent of minimum price, no producer ownership, plus thirty percent of price, one hundred percent producer ownership.

[9]Net-back gas price or $2.00, whichever is less, plus difference between minimum required price for NGL, thirty percent producer ownership of ANGTS and the net-back gas price.

twenty-five years. The rate of decline is much faster after adjusting for inflation, as is illustrated in the table. The figures in Table 4 show clearly that under either a cost-plus price or a net-back price system, the withdrawal of NGL from the ANGTS pipeline will raise the charge on the remaining throughput. The resulting increase in the transportation charges which arises from charging the fixed capital cost to a smaller throughput serves to make it more difficult to market the gas in the first years under a cost-plus price system, while lowering the net-back price still farther below zero.

If the price ceiling were lifted and the gas producers were to own one hundred percent of the ANGTS pipeline, then they would be indifferent about the way in which the tariff were set in the net-back case. The savings to the producers in pipeline costs of withdrawing NGL from ANGTS would in this case be only the operating cost. Table 4 shows how much the value of keeping the NGL in the gas stream (the marginal cost of withdrawing NGL) would increase above the value of the sales gas without NGL withdrawal, depending on ownership of the ANGTS project.

Another possibility that would materially increase the chances for financial viability of ANGTS would be a tariff mechanism based on reproduction cost of the pipeline. Such a concept, roughly similar to the "fair-value" principle of regulating oil pipelines used by the Interstate Commerce Commission more nearly approximates the internal valuation of transportation cost by the pipeline owners if the pipeline were deregulated. With this type of tariff mechanism, the fixed cost of the gas pipeline would start out at a lower level, but would increase with inflation (along with the reproduction cost). Table 5 illustrates the same calculations made in Table 4 for the fair-value type of tariff mechanism. The figures in Table 5 suggest that the sponsors of the petrochemical project would have to pay the gas producers around twice as much for the gas liquids per MMBTU than the net-back value of the gas, in order for the producers to gain from withdrawing the liquids from the gas stream.

One would suppose in general that the producers would sell NGL (or methane) for petrochemical production, or process it themselves, if the price were higher than the value as part of the ANGTS gas stream. This value, as suggested in Tables 4 and 5, would be significantly higher than the price of gas using the net-back price system. However, the discussion of net-back prices must consider the impact of Natural Gas Policy Act price regulations. If the net-back price is limited to \$2.00/MMBTU (in 1981 prices), the producers might be able to sell NGL for chemical feedstocks (if extracted and sold in the field as under the Dow-Shell plan) at a higher price per BTU than the price ceiling.

The last line of Tables 4 and 5 shows how the minimum required price for the producers to receive for a sale of NGL to a petrochemical project is significantly lowered by the presence of the regulatory ceiling price of gas. Thus, the way in which federal regulation affects well-head gas prices may cause the gas producers to commit NGL to petrochemical production, despite its possibly higher economic value as part of the ANGTS gas stream.

Potential for State Efforts to Reduce the Risk

This paper has discussed three main areas in which the development of a gas-liquids-based petrochemical industry may add risk to the proposed Alaska Natural Gas Pipeline Project. First, it is not certain that there will be sufficient gas supplies available on the North Slope to run both the gas pipeline at its full capacity and allow for full development of the petrochemical industry under current field rules. While additional gas resources are known to exist as has been shown in Table 2, it is questionable whether these new reservoirs can contribute to pipeline throughput in this century.

Secondly, the possibility that the construction phase of the petrochemical project may overlap that of the gas pipeline has the potential to add greatly to the likelihood of cost overruns for the ANGTS project. Finally, there are many regulatory uncertainties surrounding the treatment of North Slope gas. What is known about the rule for setting the ANGTS tariff and the ceiling price for gas suggests that the financial risk of the ANGTS project is increased by the availability of an unregulated market for natural gas liquids.

In the first two instances, the problem arises from the fact that the schedule for development of the petrochemical industry may not necessarily consider its full impact on the gas pipeline project. The producers have a major interest in the schedule as it relates to the availability of gas supplies, but their flexibility may be limited by regulation by the Oil and Gas Conservation Commission.

It is not within the writer's area of expertise to evaluate whether a higher rate of gas sales than 2.7 bilion cubic feet per day of unconditioned gas from the Sadlerochit Reservoir will harm oil or gas recovery. It is important to note, however, that the Conservation Committee set this rate in 1977, before much was known of the oil producing history of the reservoir. It is possible that new information might lead the Commission to revise upward the allowable rate of sale of gas. If so, this would relieve at least temporarily the constraint on North Slope gas supplies. The state, through the Department of Natural Resources, could press for a rehearing of the allowable gas sales rate to consider this possibility.

The producers also have an interest in scheduling the construction of the two pipeline projects to reduce the likelihood of cost overruns and, perhaps, take advantage of cost savings from complementary aspects of construction. However, if the state is concerned about the broad social impacts arising from pipeline construction, it might perceive a greater interest in scheduling than the producers, for two reasons. On the one hand, the producers will own only a minority interest in the gas pipeline, and under certain regulatory scenarios, they may not be at risk even indirectly for a large share of the cost overruns. On the other hand, the spillover effects from congestion of labor markets would lead to impacts throughout the economy. Boom town impacts on local communities do not necessarily affect the producers at all, but may at some point be of concern to the state.

The state technically has the ability to influence through its issuance of right-of-way across state lands whether construction of the petrochemical industry is able to work around the construction phase of the gas pipeline, and vice versa. Such an influence could mitigate substantially the social impacts likely to be caused by potential congestion of labor markets and support services. While the office of the pipeline coordinator has the role of representing the state's interest in mitigating social impacts of construction of the NGTS project, this agency has neither the authority nor the legislative mandate to influence the construction schedule of either proposed pipeline. If the state were to perceive an important public interest in reducing potential boom-town problems, major new legislation would be required to expand the powers of the pipeline coordinator, as well as to give matching orders to the Commissioner of Natural Resources for conditions on the sale of royalty gas. But unless and until the legislature is able to articulate a clear policy interest in avoiding potential social impacts of pipeline construction, the state is implicitly accepting on faith that the producers, who definitely have the ability to control the scheduling of both projects, will act sufficiently in the public interest in this regard.

Finally, the state should consider carefully its interest in the federal rules for regulating the price and transportation of natural gas. Although the analysis in this report is based on hypothetical cost and rate data, the alternative scenarios shown in Tables 4 and 5 suggest that deregulation of natural gas prices would allow the producers to capture enough profit on future sales of gas to compensate them for a temporarily low, if not negative well-head price at first. Deregulation would also allow the producers to evaluate the withdrawal of NGL for petrochemical manufacture based more on the true costs than is likely to be the case under the Natural Gas Policy Act price ceiling. This would reduce the potential risk to the gas pipeline project due solely to arbitrary regulatory rules.