NATURAL GAS CONDITIONING AND PIPELINE DESIGN

A Technical Primer for Non-Technicians,
With Special Reference to Hydrocarbons from Prudhoe Bay
and the Alaska Highway Gas Pipeline

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INTRODUCTION

The State of Alaska faces a variety of questions related to the proposed Alaska Highway Gas Pipeline which combine highly technical engineering considerations with important public policy issues. These questions include:

— location, design, and ownership of the gas conditioning plant,
-- choice of fuel for North Slope operations, and
— pressure and diameter specifications of the pipeline itself.

Some grasp of the engineering jargon and basic principles is essential if Alaska's elected officials and agency staff are to identify the State's priorities correctly: What issues really affect the State's interests, and to what extent? Which, if any, of the other parties --- the producers, gas shippers, and federal authorities --- are likely to share the State's interests in each of these questions, and to what extent? How much can Alaskans depend on others, therefore, to look after the State's interests? How formidable is opposition likely to be to the State's position, and what burdens would the State's demands impose on others? Overall then, where should the State realistically direct its efforts?

This report, in itself, will not answer those questions; it should, however, make State decision-making a bit easier. We have tried to distinguish scientific facts from matters of differing engineering judgment, and both from differences of economic interest; and to present the range of opinions fairly. Our goals have been to develop a primer on gas conditioning and pipeline transportation that is relevant to Alaskans, speaks to non-technicians, yet is precise and complete enough to survive the scrutiny of experts.

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I. THE BASICS OF PIPELINE DESIGN

A. HYDROCARBON CHARACTERISTICS

1. Chemistry

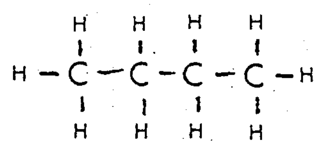
The crude oil and natural gas produced from Alaska's Prudhoe Bay reservoir are mixtures of hydrocarbons (compounds of carbon and hydrogen), plus impurities like water and carbon dioxide. The most fundamental classification of hydrocarbon compounds is in terms of the number of carbon atoms in each molecule.

TABLE 1

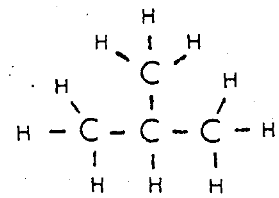
Reservoir Fluid	Compound	Chemical Formula	Abbreviation	Commercial Product
	methane	CH_4	C_1	dry gas
	ethane	C_2H_6	C_2	
natural gas	propane	C_3H_8	C_3	natural gas liquids (NGLs) or condensate
	butane	C_4H_{10}	C_4	
	pentane	C_5H_{12}	C_5	
	hexane	C_6H_{14}	C_6	natural gasolines, naphtha, or pentanes-plus
	heptane	C_7H_{16}	C_7	
crude oil	octane	C_8H_{18}	C_8	
	-	-	-	oils, waxes, tars
	-	-	-	
	etc.	C_nH_m	C_n	

Hydrocarbons containing more than three atoms of carbon in each molecule have several different configurations. These forms or "isomers" often have different physical characteristics. For example, Table 2 shows that "normal" butane [n-butane] can remain in a liquid state in the TAPS oil pipeline at higher temperatures than can the branched isomer "iso" butane [i-butane].

FIGURE A: NORMAL AND ISO-BUTANE



"normal" (n) butane



"iso" (i) butane

2. Heating values

The heating value of each hydrocarbon reflects, in part, the number of carbon atoms that will oxidize as the fuel is burned. Table 2 shows the heating values of light hydrocarbons and their isomers, both in liquid and vapor states. Normally, heating values are expressed in gross BTU's[1], also called the higher heating value. The expected heating value of gas that will be shipped through the Alaska Highway gas pipeline (or Alaska Natural Gas Transportation System [ANGTS]), for example, is invariably expressed in gross terms.

The lower heating value, measured in net BTU's, serves a very limited function, primarily in describing the fuel requirements for various types of machinery and processes. Net BTU's for hydrocarbon vapors have been used by some parties involved in the design of the North Slope gas conditioning plant; Table 2, therefore, includes net measurements for hydrocarbon vapors.

The difference between gross and net BTU's is highly technical. The reader need only remember that (1) unless specifically designated as net BTU's, one can assume that all heating value data represent gross measurements; and (2) like apples and oranges, the two should never be confused or mixed in heating value calculations.

1) A British Thermal Unit (BTU) represents the amount of heat required to raise the temperature of one pound of water by one degree F.

TABLE 2

HYDROCARBON	VAPOR HEATING VALUE		LIQUID HEATING VALUE
	BTU/scf* gross	BTU/scf net	BTU/barrel** gross
Methane	1010	909	2,512,818
Ethane	1769	1618	2,771,916
Propane	2518	2316	3,824,730
i-butane	3253	3001	4,158,924
n-butane	3262	3010	4,325,538
i-pentane	4000	3698	4,569,180
n-pentane	4010	3708	4,624,284

Source: Natural Gas Processors and Suppliers Association, Engineering Data Book, 1979.

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* A Standard Cubic Foot (scf or cf) is the amount of gas that would fill a cubic foot of space at 60 degrees F. and standard atmospheric pressure. The following abbreviations are often used to represent large volumes:

Mcf = thousand cubic feet
MMcf = million cubic feet
bcf = billion cubic feet
Tcf = trillion cubic feet

** One barrel = 42 U.S. gallons.

3. Phase characteristics

The more carbon atoms a molecule contains, the heavier it is. The heaviness of a particular hydrocarbon will influence whether it exists in a vapor or liquid phase at various combinations of temperatures and pressures. Table 3 shows the boiling points of light hydrocarbons. At temperatures below the boiling point, a hydrocarbon is a liquid; above, it is a vapor.

TABLE 3

SUBSTANCE	MOLECULAR WEIGHT	BOILING POINT (F.) [at atmospheric pressure]
C_1	16.043	−258.69
C_2	30.070	−127.48
C_3	44.097	− 43.67
i-C_4	58.124	+ 10.90
n-C_4	58.124	+ 31.10
i-C_5	72.151	+ 82.12
n-C_5	72.151	+ 96.92
n-C_6	86.178	+155.72
n-C_7	100.205	+209.17
n-C_8	114.232	+258.22
CO_2	44.010	−109.30

Source: Natural Gas Processors and Suppliers Association, Engineering Data Book, 1979.

Oil is now injected into the Trans Alaska oil pipeline (TAPS) at a temperature of 142 degrees F. At times, the oil may experience pressures enroute as low as normal atmospheric conditions. Under these circumstances, Table 3 shows that hexanes (C_6) and all heavier hydrocarbons would always remain in a liquid phase during shipment through TAPS. Mixtures of heavy hydrocarbons also have the ability to carry small quantities of C_5 and even C_4 without vapor formation. On the other hand, mixtures of the lightest hydrocarbons (C_1, C_2, and C_3) remain in the vapor phase even in a chilled gas pipeline, and can likewise absorb some C_4 and possibly C_5 without condensation.

The question of how much of these intermediate hydrocarbons (C_4 and C_5) will be carried as vapors by ANGTS, shipped as liquids in TAPS or in a third "gas-liquids" pipeline, used for fuel on the North Slope, or routed to some other purpose, remains open. Resolution of this issue depends upon a whole array of decisions, including pressure and temperature specifications for operation of both the gas and oil pipelines, the amount of CO_2 permitted in the gas pipeline, the choice of gas conditioning process, the kinds and amounts of fuel used in the field and for pipeline pumps and compressors, and oil and gas production rates. This report examines each of those factors, their relationships, and the ultimate effect such decisions may have on the kinds and amounts of hydrocarbons transported.

B. GAS VERSUS LIQUIDS PIPELINES

Pipelines carrying hydrocarbons in a liquid phase (such as the TAPS oil line and a proposed gas liquids line) use pumps to move these materials. Pipelines designed for gaseous hydrocarbons, such as the proposed Alaskan Northwest pipeline, use compressors. The difference is subtle, but important.

In liquids, the individual molecules are packed tightly together and, for all practical purposes, cannot be compressed into a smaller volume. Instead, as more molecules are pumped into a pipe, they shove the mass of hydrocarbons in front of them into the next pump station, like a train of boxcars pushed from behind. Naturally, the greater the distance (and the greater the rise in elevation) between pump stations, the greater is the horsepower required.

Gaseous hydrocarbons, like all vapors, are compressible. Each compressor station on a gas pipeline draws vapor into its inlet at a relatively low pressure (called the suction pressure), compresses it into a smaller volume, and expels it at a higher pressure, known as the discharge pressure. As the gas expands between the outlet of one compressor station and the inlet of the next, pressure again falls, and this pressure drop or differential causes the gas to flow through the pipe. It is the discharge or operating pressure, being the greatest pressure experienced by the pipeline, that is limited by the strength of the steel pipe.

C. PRESSURE SPECIFICATIONS

Pressure drop is usually measured as a ratio to distance, psi per mile.[2] Being the stimulus for gas movement through a pipeline, it is therefore one of several factors that determine how much gas can be transported each day. Throughput is determined by the following components:

(1) Discharge pressure, (2) Suction pressure, and (3) Compressor Station spacing determine the pressure drop, and thereby the SPEED of flow, while

(4) Pipeline diameter determines the AMOUNT of gas that can be shipped through a pipeline at any given speed.

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2) Pressure is measured in pounds per square inch (psi). Objects at sea level are subjected to an atmospheric pressure of about 14.7 psi (which results from the weight of several miles of air resting on the earth's surface). Instruments designed to measure artificially induced pressures like those inside gas pipelines, record or guage pressures in excess of this ever-present atmospheric pressure (psig). Absolute pressure measurements include the 14.7 psi exerted by the atmosphere (psia). Hence, 1680 psig is the same as 1694.7 psia.

Of these four variables, a pipeline's diameter and the maximum discharge pressure that it can accomodate (that is, the pipeline's operating pressure) are the only ones that cannot be altered once the pipe is laid. The other two can, in theory, be modified to accomodate changes in throughput: Throughput can be increased either by adding more compressor stations or by increasing the suction power of existing compressors.

There are, of course, practical and economic constraints on the number of compressor stations that can be added. Likewise, the suction power of compressors experiences a marked drop-off in efficiency beyond a given range of compression ratios.

The compression ratio is the ratio between a compressor's discharge pressure and its suction pressure. Compression ratios are generally in the vicinity of 1.2 to 1.3. Table 4 shows the suction pressures corresponding to a compression ratio of 1.25 at four operating pressure levels heretofore considered for the Alaskan and Canadian sections of the Alaska Highway Gas Pipeline.

TABLE 4

Operating pressure	Efficient Delivery Pressure
1680 psig	1350 psig
1440 psig	1150 psig
1260 psig	1010 psig
1080 psig	860 psig

The National Energy Board (NEB) has approved construction of a 1080 psig 56 inch diameter pipeline in Canada. Though some contention still exists on the matter, the Federal Energy Regulatory Commission (FERC) has approved the design proposed by the pipeline sponsor, Northwest Alaskan, with an operating pressure of 1260 psig for a 48 inch pipeline in Alaska. EXXON and the State of Alaska have advocated higher operating pressures, such as 1680 psig (or even 2160 psig for a 42 inch diameter pipe). ARCO at one time proposed a compromise pressure of 1440 psig.

The controversy over the pipeline's operating pressure and diameter stems, in part, from a recognition that manipulating discharge and suction pressures or even building more compressor stations after the pipe is laid are not necessarily the most economic or practical responses to future changes in throughput. For these reasons, designers must choose pipeline diameter and wall thickness specifications and compressor station locations that reflect a realistic judgment of likely throughputs over the life of the facility. FERC and Northwest concluded that a 1260 psig 48" diameter pipeline is the most efficient and economic compromise for the volume of gas expected from the main Prudhoe Bay reservoir (about 2.0 bcf/day). However, they agree that at a throughput somewhere between 2.6 and 2.9 bcf per day, a 1680 psig line would make more sense. ["Report of the Alaskan Delegate on the System Design Inquiry", FERC, May 17, 1979; p. 27.]

Unfortunately, the additional volumes of North Slope gas likely to become available during the expected 20 or 25 years of gas pipeline operations are both uncertain and controversial. No one can know with confidence whether the 1260 psig system ultimately will prove to be the best choice.

A related issue that must be addressed during engineering design is the need for <u>crack arrestors</u>. Even if a pipeline's wall thickness is sufficient to withstand its own INTERNAL gas pressures, pipeline designers have to safeguard against the effects of catastrophic EXTERNAL forces --- such as a misguided bulldozer or a saboteur's bomb.

Obviously, localized damage cannot be prevented entirely. In a large diameter, high pressure gas pipeline (unlike TAPS), however, even a small injury to the pipe can result in a fracture that spreads explosively up and down the system, perhaps destroying pipe for tens of miles. Girdling the pipe at regular intervals with sturdy metal crack arrestors is one solution.

Virtually everyone agrees that a 1680 psig, 48 inch diameter pipeline must be equipped with crack arrestors. Opinions, however, vary with respect to a 1260 psig system. Since crack arrestors are a significant expense, no conclusive judgment about the relative economic advantages of a 1260 psig system can be reached in the absence of a decision on the need for crack arrestors.

Probably the biggest source of controversy with respect to the selection of an operating pressure for the Alaska Highway Gas Pipeline centers, however, on the ability of higher pressure pipelines to carry heavier hydrocarbons without risking <u>two-phase flow</u>.

D. HAZARDS OF TWO-PHASE FLOW

Long-distance pipelines must be designed to carry hydrocarbons either in a vapor phase (like the Northwest pipeline) or in a liquid phase (like TAPS and the proposed gas liquids line). Transporting vapors and liquids together in one stream results in a condition called <u>two-phase flow</u>. The dangers of two-phase flow are as follows:

(1) General problems of two-phase flow. A pump or compressor is designed to operate on material of a certain density. Encountering bubbles of vapor in a stream that should be totally liquid is a little like swinging a bat at a baseball and missing; while coming across droplets or, worse yet, big "slugs" of liquid in a stream that should be all vapor is like being hit with a barrage of snowballs. Either event can be rather jarring to the system.

(2) "Surge" and "slug" problems of two-phase flow. If droplets of liquids condense in the vapor stream, they tend to settle and accumulate in low spots along the pipeline, constricting the room available for vapor flow. As the amount of trapped liquid grows, pressure builds --- eventually forcing the liquid up and over the next hump. Large slugs of dense liquids are, therefore, accompanied by an uneven or surging flow of fluids. Extreme surging conditions can cause severe damage when a slug enters a compressor station.

It should be noted that some pipelines are intentionally operated in two-phase flow conditions, while gathering "wet" (unconditioned) gas in the field, or bringing gas from offshore wells to shore-based facilities. Usually, however, these pipelines are quite short and undersized; no pumps or compressors that could be damaged by surging slugs are located along the way. In fact, some offshore pipelines for which slug formation cannot be avoided empty onshore into several miles of convoluted pipeline called slug catchers. Here the tremendous force of the slugs is dissipated, and the liquid itself is "scrubbed" out of the gas, prior to entering pumping, processing, or compressing facilities.

Designers and operators of long-distance gas pipelines, like the ANGTS which has several compressor stations and many ups and downs enroute, can take a variety of actions to reduce the hazards of two-phase flow. They can:

* Avoid building an oversized line. One way to prevent the accumulation of liquids at low points along the line is to ensure that vapors flow at a high speed. This means choosing a pipeline diameter appropriate to the expected throughput, maintaining a high pressure drop, or both. If a system is designed to carry an average of 3.0 bcf/day and only 2.0 bcf/day is available for shipment, pressure drop would have to be reduced in order to ensure a steady flow of the smaller volume of gas. The result is a slower movement of gas and, hence, a greater danger of slug formation and surging.

* Equip the line with drains. Valves to drain off accumulated liquids can be inserted in low spots along the pipeline.

* Ensure against sloppy pipeline operations. If drains are installed, they must be used properly. If adequate drainage is impractical, the line should receive more frequent "pigging" (insertion of a solid object, or pig, which pushes accumulated liquids out ahead of it). If throughput is raised or lowered, changes in the input and output pressures must be synchronized. If the line is shut down temporarily, special care must be taken when operations resume to prevent the passage of entrained liquids that may have formed during the outage. For these reasons, no matter how free of droplets the sales gas may be when it enters the pipeline, sloppy operations can result in dangerous two-phase flow conditions.

None of the above precautions are of much use in long-distance pipelines, however, unless pipeline operators also:

* <u>Restrict the volume of heavy hydrocarbons</u>. Pipelines must transport only hydrocarbon mixtures that pose no threat of condensation at any combination of temperatures and pressures likely to be encountered under either normal or abnormal conditions. Determining the optimum mixture is rather complicated, as the next chapter shows.

II. GAS COMPOSITION DECISIONS

A. INTRODUCTION

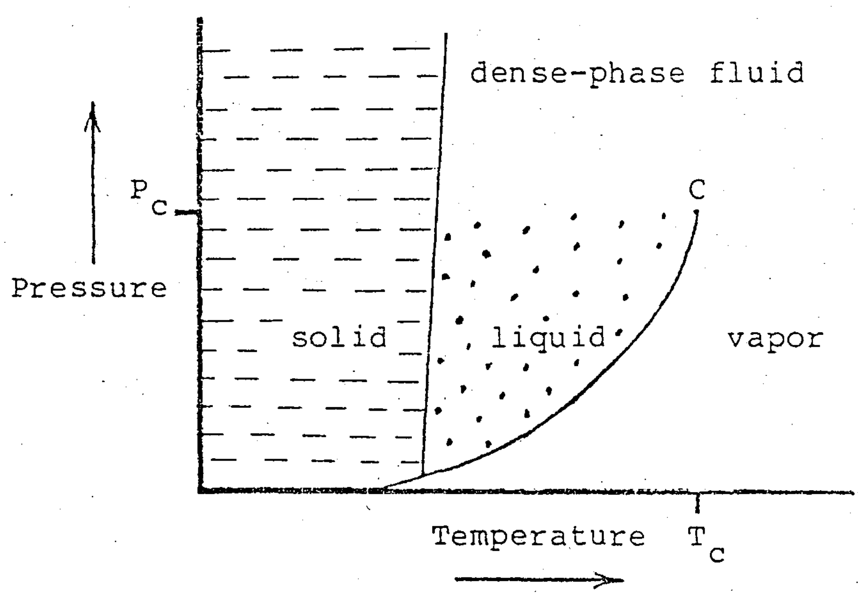
In designing a gas transportation system, everything seems to affect and be affected by everything else. We have seen, for example, that decisions about pipeline diameter, operating pressure, suction pressure, and compressor station spacing are all interdependent. Further, these specifications cannot be set intelligently except with reference to some volume or range of volumes for expected throughput. The same holds true with respect to determining the optimum chemical composition of <u>pipeline quality gas</u>; that is, the relative amounts of methane, ethane, propane, butane, heavier hydrocarbons, carbon-dioxide, water, and sulphur compounds in the gas delivered to the pipeline.

Temperature and pressure are the two factors that determine whether any particular hydrocarbon or mixture of hydrocarbons will be present in a vapor or in a liquid phase. Thus, pipeline designers must choose a balanced combination of pressure, temperature, and composition specifications that will ensure safe operations and avoid two-phase flow.

B. PHASE DIAGRAMS

Almost everyone is familiar with "bottle gas" -- pressurized containers of propane and butane used to fuel appliances in isolated homes, mobile homes, and recreational vehicles, and for camping stoves and lanterns. The propane or butane exists as a liquid inside the containers, but vaporizes upon release. Heavier hydrocarbons like gasoline and diesel fuel are liquids at atmospheric pressures and temperatures but vaporize when heat is added. These are all examples of phase changes. Each hydrocarbon has its own phase diagram, like that of Figure B, which shows how changes in pressure and temperature affect its physical characteristics.

FIGURE B: PHASE DIAGRAM OF A PURE SUBSTANCE



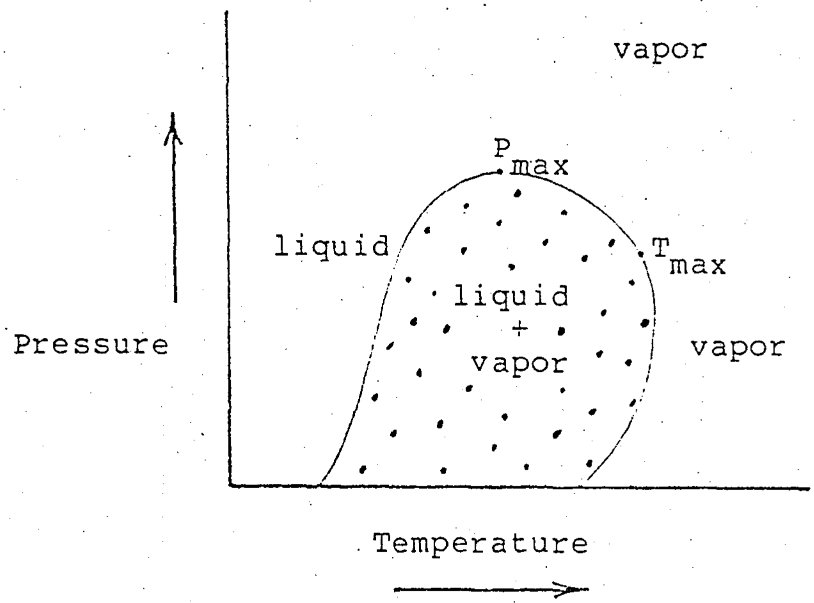
Notice first, that four phases are shown: solid, liquid, vapor, and something called dense-phase fluid. Unlike the other phases, it is hard to pinpoint where the dense phase fluid starts and ends; but we do know that it occurs only at extremely high pressures. It is also difficult to describe: A dense-phase fluid is dense like a liquid, but compressible like a vapor. And unlike solids, liquids, and vapors, which we all encounter in our daily lives, dense-phase fluids exist only deep inside the earth and within artificially created environments like natural gas pipelines.

While this high pressure phase is technically a creature unto itself, for our purposes there is no practical distinction between such fluids and vapors, and we shall generally use the word vapor for both.

Point C in Figure B is called the critical point. For any pure substance, no liquid can exist at pressures above the critical pressure (P_C) --- no matter how far the temperature drops. Likewise, no liquid can exist at temperatures beyond the critical temperature (T_C) --- again, no matter how much pressure is exerted.

Unfortunately phase diagrams of hydrocarbon MIXTURES, like that of Figure C, are more complicated to read and understand than are the diagrams of pure substances. For volumes containing only a single hydrocarbon type, two phases will coexist only at pressure-temperature combinations represented by the thin line separating liquid and vapor phases. But for hydrocarbon mixtures, the net effect of all the individual phase diagrams is a tongue-shaped region or phase-envelope in which both gas and liquid states are present. To avoid two-phase flow in pipelines, therefore, any combination of temperature and pressure falling inside the phase envelope must be avoided. Liquids pipelines must operate to the left of the phase envelope, while gas pipelines must function above or to the right of it.

FIGURE C: PHASE DIAGRAM OF A MIXTURE



The temperature and pressure combinations that delineate the right and upper boundaries of the phase envelope are called <u>dewpoints</u>, marking the conditions at which droplets first begin to appear in a vapor as the temperature or pressure falls. The combinations along the left side of the phase envelope are called <u>bubblepoints</u>, marking the conditions at which bubbles of vapor first appear in a liquid. TAPS engineers, therefore, worry about bubblepoints, while ANGTS engineers fret over dewpoints. The next chapter will examine how engineers use phase diagrams to determine what mixtures of light hydrocarbons can be handled safely in ANGTS.

THE RELATIONSHIP BETWEEN GAS COMPOSITION AND UPSET CONDITIONS

While the choice of operating (or discharge) pressure has thus far dominated the discussion of two-phase flow, the operating pressure in itself does not limit the allowable range of gas mixtures. Likewise, the temperature at which gas is discharged from each compressor station is not the limiting factor. Instead, project engineers concern themselves with the combination of pressure and temperature conditions that would occur in a system upset.

As the term implies, upset conditions are those that occur when the system malfunctions. Engineers study upset conditions in order to forecast the most troubling combination of temperature and pressure (from the standpoint of two-phase flow) that vapors moving through the gas pipeline are likely to encounter. Since ANGTS will be designed to carry light hydrocarbons in a high pressure vapor phase (more precisely, a dense-phase fluid), upset conditions denote the LOWEST expected combinations of temperature and pressure.

How are upset conditions determined? First, the normal operating window of pressures and temperatures must be calculated. This represents the range of conditions likely to occur, assuming that the system is functioning properly. The lowest pressure experienced under these normal conditions is the suction pressure, which occurs at the entrance to each compressor station.

Calculating the lowest temperature likely to occur under normal operating conditions is more difficult. It depends, in part, upon the temperature at which gas is ejected from the compressor stations. Interestingly, the Canadian pipeline segments south of Whitehorse have an advantage on this point. Compressor stations in Alaska must discharge gas with a temperature no higher than 32 degrees F., in order to prevent melting of permafrost through which the buried pipeline is laid. However, south of Whitehorse permafrost is a relatively minor problem and discharge temperatures, therefore, can be higher.

The lowest limit of acceptable gas temperatures is a function of the pipe's ductility and other physical characteristics. In the present preliminary design, this lower limit is -10 degrees F. Minimum normal operating temperatures are, in turn, determined mainly by the Joule-Thompson cooling effect: a gas naturally falls in temperature as it expands between its discharge from one compressor and its delivery to the next. The lowest operating temperature also depends upon what ground or air temperatures the designers expect to occur along the pipeline route. As long as the pipeline in Alaska is buried, the temperature it encounters will stay around 10 degrees F. throughout the year. If any section of the pipeline is constructed above ground, however, the cold Arctic winters become a real concern.

Once pipeline designers determine the normal operating window of temperatures and pressures, they can forecast the effects of specific malfunctions. Calculation of the resulting upset conditions reflects the designer's judgment as to WHICH malfunctions must be accomodated. Generally, upset conditions that have been discussed with respect to the Alaska gas pipeline reflect an assumption that the worst case would be one in which a single compressor station is totally shut down for repairs. But the implications of this assumption depend also on WHICH station is out of service. Moreover, the worst conditions under which the system will operate are also a function of how much the pipeline's designers and operators are prepared to reduce throughput in case of an upset: Will they simply route the

the gas past the ailing station without increasing the suction capability downstream? Or will the next station be forced to work harder in an attempt to keep throughput from falling too severely? Again, determining how much the operator can manipulate suction pressure at the downstream station depends upon the minimum stress temperature of the steel pipe (-10 degrees F, as we mentioned previously), the mechanical limitations of the machinery, and the dewpoint characteristics of the gas itself.

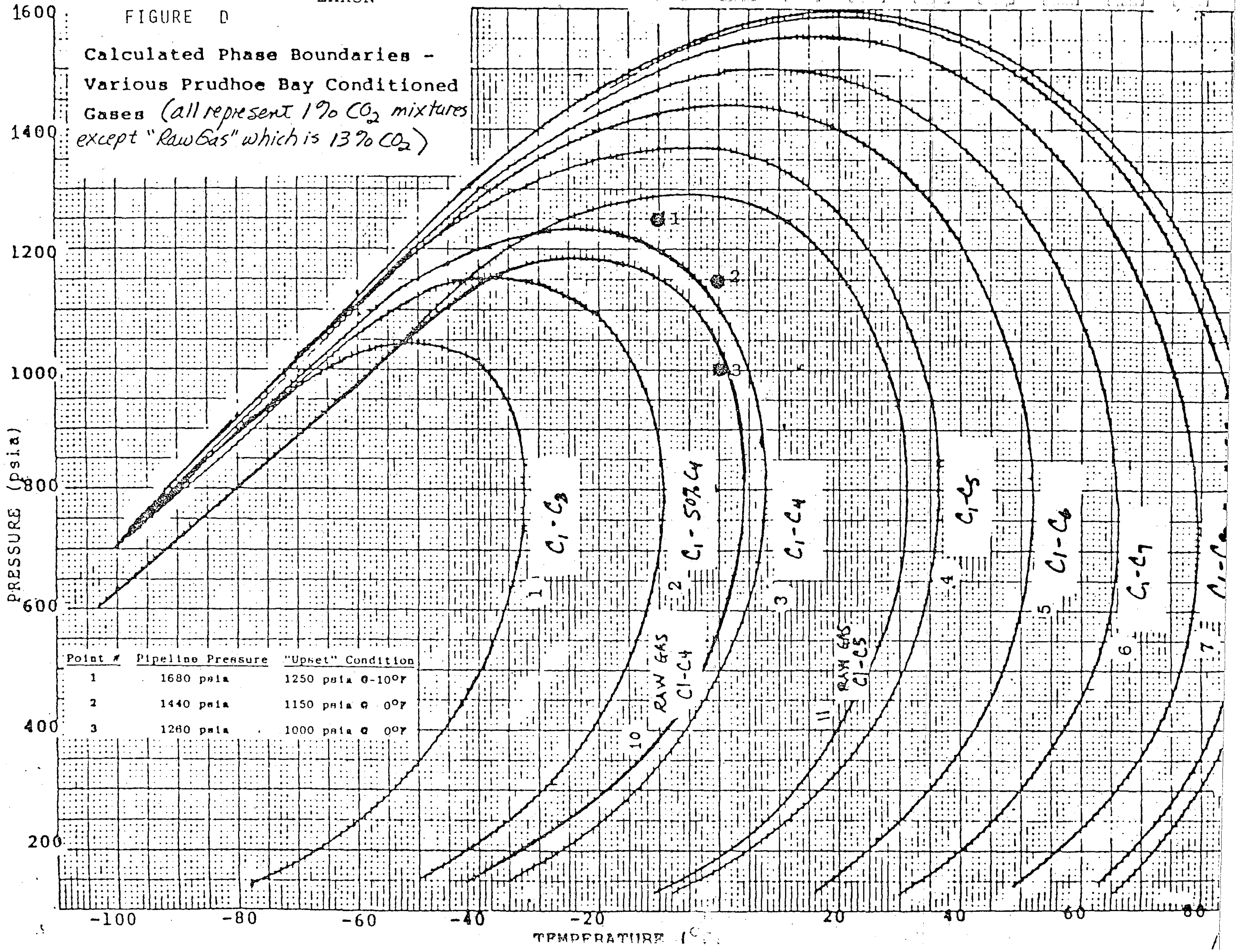
Figure D plots the temperatures and pressures of assumed upset conditions for the several pipeline operating pressures under consideration, and illustrates how close these points come to the two-phase flow conditions of various North Slope hydrocarbon mixtures. While an understanding of the basic physical principles reviewed here is important, no one can precisely assess the system's upset temperatures and pressures except in conjunction with detailed engineering and contingency plans. This explains why different parties have projected different upset conditions for ANGTS.

Figure D shows, for example, why upset conditions for the Canadian pipeline sections are of no real concern with respect to choice of gas composition. Even though the Canadian pipeline will function at a lower operating pressure (1080 psig, with a corresponding upset pressure of about 860 psig), it will have a significantly higher upset temperature (around 30 to 40 degrees F.) because the lack of permafrost south of Whitehorse permits higher compressor discharge temperatures. If one plots the intersection of 860 psig and 35 degrees F., it is evident that the design of the Alaska portion of the pipeline will be what limits the volume of intermediate hydrocarbons shipped through the entire system.

EXXON

FIGURE D

Calculated Phase Boundaries - Various Prudhoe Bay Conditioned Gases (all represent 1% CO_2 mixtures except "Raw Gas" which is 13% CO_2)



Point #	Pipeline Pressure	"Upset" Condition
1	1680 psia	1250 psia @ -10°F
2	1440 psia	1150 psia @ 0°F
3	1260 psia	1000 psia @ 0°F

EXXON

VARIOUS PRUDHOE BAY CONDITIONED GAS COMPOSITIONS
(Mole Percent)

Component	Unconditioned Separator Off-Gas	1 C_1-C_3	2 C_1-50%C_4	3 C_1-C_4	4 C_1-C_5	5 C_1-C_6	6 C_1-C_7	7 C_1-C_8	8 C_1-C_8	9 C_1-C_9	(Off- C_1
N_2	0.484	0.564	0.559	0.554	0.551	0.550	0.549	0.549	0.549	0.549	0.
CO_2	12.659	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	12.
C_1	74.706	87.053	86.296	85.554	84.964	84.818	84.742	84.695	84.679	84.676	75.
C_2	6.428	7.491	7.426	7.362	7.311	7.299	7.292	7.288	7.287	7.287	6.
C_3	3.340	3.892	3.859	3.826	3.799	3.793	3.789	3.787	3.786	3.786	3.
i-C_4	0.450	--	0.260	0.515	0.512	0.511	0.511	0.510	0.510	0.510	0.
n-C_4	1.038	--	0.600	1.189	1.181	1.179	1.178	1.177	1.177	1.177	1.
i-C_5	0.217	--	--	--	0.247	0.247	0.246	0.246	0.246	0.246	-
n-C_5	0.383	--	--	--	0.435	0.435	0.434	0.434	0.434	0.434	-
C_6	0.148	--	--	--	--	0.168	0.168	0.168	0.168	0.168	-
C_7	0.081	--	--	--	--	--	0.091	0.092	0.092	0.092	-
C_8	0.047	--	--	--	--	--	--	0.054	0.054	0.054	-
C_9	0.016	--	--	--	--	--	--	--	0.018	0.018	-
C_{10}	0.003	--	--	--	--	--	--	--	--	0.003	-
Molecular Wt.	22.7	18.5	18.8	19.2	19.5	19.7	19.8	19.8	19.8	19.9	22.
Heating Value (Btu/cf*)	1027	1095	1113	1131	1150	1156	1160	1163	1164	1164	996

*Gross, Wet, Actual @ 60°F., 14.73 psia

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Alaska state officials thus far have argued that decisions regarding pipeline design and gas composition should not preclude shipment of intermediate hydrocarbons such as butanes. (This position will be discussed in more detail later.) However, when the time comes to develop firm contingency plans for upset conditions, the State's interest in shipping intermediate hydrocarbons through the gas pipeline may well be surpassed by its likely --- and conflicting --- interest in maintaining high throughput levels: As the preceding discussion shows, in the event of upset, maintenance of throughput depends on an ability to reduce the suction pressure at the next compressor station, which in turn is partly limited by the proportion of intermediate hydrocarbons in the gas stream.

D. CARBON DIOXIDE CONTENT

<u>Produced</u> gas from the field (sometimes called <u>raw</u> gas) contains about 13 percent carbon dioxide (CO_2). Whether that amount is allowed to remain in the <u>pipeline quality gas</u>, or is removed via <u>conditioning</u>[3] down to a 1 percent or 3 percent level, depends on several factors:

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3) Some parties with an interest in ANGTS have used the words "gas conditioning" and "gas processing" interchangeably; and in many Lower 48 producing areas, the boundary between the two stages of natural gas treatment is hard to define. With respect to Prudhoe Bay natural gas, these two phrases have distinct <u>regulatory</u> definitions, which may result in very real differences in the price the law allows gas producers to receive. As a result, the producers are easily aggrieved by any "misuse" of the two terms. We will make no attempt here at a rigorous distinction between gas processing and conditioning; the reader should simply be aware of the sensitivity of this matter.

1. <u>The effect of carbon dioxide on hydrocarbon dew-point</u>. Figure D shows that a 13 percent CO_2 mixture enables the introduction of greater quantities of heavy hydrocarbons than would be safe with a 1 percent CO_2 mixture, but the effect is really rather small. Instead, the choice of CO_2 concentration must be made on other grounds.

2. <u>The effect of carbon dioxide on pipeline corrosion</u>. Under certain conditions, carbon dioxide will combine with water to form carbonic acid. If present in the sales gas stream, carbonic acid will corrode the steel walls of the pipeline. The question, then, is how various concentrations of CO_2 affect the risk that carbonic acid will seriously damage the pipeline during the twenty-plus years of gas shipments.

The producers collectively argue that carbonic acid corrosion in the Alaskan section of the gas pipeline is a false issue, in part, because it takes two to tango. Carbon dioxide in any concentration cannot turn into carbonic acid except in the presence of "free" water (water that condenses out of the vapor phase). Since enough water must be removed to meet WATER dewpoint specifications of -35 degrees F. for the section of pipeline in Alaska, no problem should ensue unless the temperature within the pipeline falls below that point; but the HYDROCARBON dewpoint specification will have to be much higher --- somewhere around 0 degrees F. in order to maximize shipment of intermediate hydrocarbons. Thus, before carbonic acid formation could pose a serious threat to the pipeline, hydrocarbons present in two-phase flow conditions would already have made the system inoperative.

Northwest Pipeline Company counters the producers' arguments with a different concern from its own standpoint as pipeline operator. While the sales gas containing more than 1 percent CO_2 may indeed ENTER the pipeline at Prudhoe Bay in a dehydrated condition that poses no threat of corrosion, the pipeline operator must ensure that the gas REMAINS corrosion-free throughout the several thousand miles of its journey. Apparently, some water is expected to contaminate the sales gas not only as a result of upset conditions, but even during hydro-testing associated with pipeline start-up. Whether Northwest's demand for a 1 percent CO_2 specification, therefore, is reasonable, has not yet been decided by FERC.

Because of permafrost problems in Alaska, the temperature of the gas must be held below the freezing point of water. Hence, if any water drops out in Alaska, it will likely do so in the form of ice or more precisely, hydrates, which are like ice crystals but encapsulate molecules of light hydrocarbons or sulphur compounds within their structures. At the planned operating temperatures for the Alaska pipeline segment, free water will form hydrates at temperatures as high as 60 degrees F. But ice and hydrates, unlike water, cannot combine with CO_2 to form an acid. Instead of gradual corrosion, the presence of solids will present a more immediate problem: blockage of the pipeline and its valves.

The Canadian section of the pipeline poses, perhaps, an even more fundamental concern. Canadian regulators have given preliminary approval to a water dewpoint specification for gas added to pipeline sections south of Whitehorse that is less stringent than specifications proposed for the

Alaska section. This difference, however, does not indicate any malfeasance by Canadian pipeline owners and regulators, but rather a difference in judgment about what constitutes acceptable risks in the face of added costs for prevention.

3. The effect of carbon-dioxide on downstream gas systems. Purchasers of Prudhoe Bay gas have argued that a high CO_2 content would adversely affect their interests in several ways.

In its July 1979 comments to FERC, the Natural Gas Pipeline Company of America states that a gas of 13 percent CO_2 would create corrosion problems within its own pipeline system, because that system's low-CO_2 gas from other sources has a relatively high water content. In addition, if Alaska gas contained excessive amounts of CO_2, it would have to be mixed with large quantitites of gas from elsewhere in order to ensure consistent burning characteristics.

Northern Natural Gas Company in its letter to the Alaskan Gas Project Office of FERC (dated December 7, 1978), advocates even more stringent CO_2 standards. It claims that its purchased volumes of Alaska gas will first be stored as LNG and, as such, cannot tolerate a CO_2 content that exceeds about 200 parts per million (ppm). But as the State of Alaska observed in its reply comment of June 1979, all pipeline gas must undergo CO_2 removal at the LNG plant site. The State concluded, therefore, that Northern's concern should not influence the choice of CO_2 specifications for North Slope gas.

The valid point raised by Northern, however, was that most LNG facilities are now designed to treat pipeline gas whose CO_2 content does not exceed 1 percent. Hence, the additional expense that shippers must bear to treat 3 percent CO_2 gas must be taken into account in assessing the conditioning and transportation costs for Prudhoe Bay gas.

4. <u>The effect of carbon dioxide on project economics</u>. One other area of concern has entered the debate on CO_2 specifications --- overall project economics. How would different CO_2 levels affect the cost of conditioning versus the cost of pipeline transportation?

The Ralph M. Parsons Company (in its February 1979 CO_2 specification study[4]) estimates that by relaxing the CO_2 removal process to yield a sales gas of 3 percent CO_2 instead of 1 percent, the conditioning plant construction costs could be pared down by about 7 percent. If no CO_2 removal facilities were built (yielding a sales gas of 13 percent CO_2), construction costs would be about half as much. Fuel requirements for the scaled-down conditioning plant would decrease by 8 percent in the 3 percent CO_2 case, and would drop by about one-third in the 13 percent case.

TABLE 5

COSTS OF CONDITIONING	1% CO_2 (base case)	3% CO_2	13% CO_2
Construction cost	100%	93%	54%
Fuel requirements	100%	92%	66%

4) The Ralph M. Parsons' studies of conditioning processes and facilities were financed jointly by the North Slope producers and a half dozen likely gas shippers (interstate gas transmission companies). It was conducted about two years ago and, necessarily, had to adopt some working assumptions in spite of the many unknowns. Consequently these assumptions and the study conclusions are not totally satsifactory to all of the sponsoring parties. The study is, however, the only in-depth analysis that presently exists; and it is, therefore, widely quoted.

Table 5 suggests that from the standpoint of conditioning costs and fuel requirements on the North Slope alone, the 13 percent CO_2 case is a clear winner. One must remember, however, that such high CO_2 levels would impose greater transportation costs, additional capital costs downstream (since CO_2 must be removed prior to customer distribution), and it threatens pipeline corrosion. The table also shows that a 3 percent CO_2 specification is preferable to one percent, but not overwhelmingly so.

On the other hand, Northwest Alaskan Pipeline Company in its February 1979 "CO_2 Transportation Study", shows that a 3 percent or 13 percent CO_2 specification would cost MORE than a 1 percent specification from the standpoint of pipeline transportation costs. (While the added volume of CO_2 contributes no additional heating value to the gas stream, it does require an increased investment in compression equipment and more fuel during pipeline operations.) But here too, the cost differences between the 1 and 3 percent CO_2 specifications are not very substantial.

In comparing how much money would be SAVED in the conditioning process by moving from a 1 percent CO_2 specification to 3 percent, versus how much additional money and fuel would be SPENT for pipeline transportation, even Northwest admits that the conditioning cost savings are of greater importance [p 5. of Northwest's "CO_2 Transportation Study"]. The difficulty for FERC will be in judging the significance of this net cost savings compared to the pipeline corrosion and downstream marketing problems previously discussed. FERC has, at least for the present, ruled that the cost of reducing CO_2 content below 3 percent, if required, is to be treated as a conditioning cost. Until the issue of conditioning cost allocation is finally decided, however, we cannot know whether it is the producers (and the State of Alaska) or the gas consumers who would benefit from an attempt to optimize total project costs.

E. VOLUMES OF GAS AND GAS LIQUIDS AVAILABLE FOR SHIPMENT

No intelligent discussion about sales gas composition can take place without some agreement as to what volumes and kinds of hydrocarbons will actually be AVAILABLE for shipment through the gas pipeline. Previous debate on the matter of gas composition has, in fact, been clouded by differing outlooks on gas availability. Worse yet, those discrepancies in underlying assumptions have largely been overlooked. Again, whether all the intermediate hydrocarbons will be ALLOWED to enter the gas pipeline for shipment is a complex question with which the rest of this report is concerned --- but that is all the more reason to make sure that hidden differences in assumptions about hydrocarbon availability are not ultimately responsible for disagreements on other matters.

This section will examine the three factors that determine how much and what kind of hydrocarbons are available for shipment through the gas pipeline: (1) reservoir production rates, (2) North Slope fuel requirements, and (3) the ability of the TAPS oil pipeline to carry intermediate hydrocarbons.

1. Reservoir production rates.

The field rules for the Prudhoe Bay reservoir currently limit raw gas production to 2.7 bcf per day, and it is expected that this rate can be maintained for 25 or more years. This rate, in turn, will yield about 2.0 bcf per day of conditioned gas. No one, of course, can guarantee that such offtake levels will indeed be physically possible, or that Alaska's Oil and Gas Conservation Commission will approve them throughout the life of the field, because the reservoir's production capabilities are based on predictions of FUTURE performance; but no one is now arguing seriously that any other figure makes more sense from the standpoint of today's planning needs.

2. Gas composition changes.

The expected hydrocarbon composition of that steady 2.7 bcf per day, however, IS expected to change through time. During the early years of gas sales, solution gas bubbling out of the crude oil will comprise the greater portion of total gas volume. But as crude oil production drops off, so will the volume of solution gas. The 2.7 bcf per day, instead, will increasingly consist of gas that comes directly out of the gas cap. Since gas cap gas is "leaner" in heavier hydrocarbons than the solution gas, the combined gas mixture, as well, will grow leaner through time.

ARCO [Dickinson letter to Tussing; January 3, 1980] estimates that by the 25th year of gas offtake, the natural gas liquids (NGL) content of the produced gas will have dropped by about 17 percent. Similarly, SOHIO [Pritchard letter to Barlow; January 23, 1980] estimates a drop-off in the ethane-propane NGL component of roughly 20 percent. The crucial issue is not, however, the absolute volumes of NGL's that must transit TAPS, but the PROPORTION of butanes in the oil stream, a ratio that promises to increase over time as oil production declines. It is nevertheless doubtful whether this trend is significant enough to merit any real consideration in system planning and design --- especially given the likelihood that during the 25 year operating period other gas reservoirs with different gas compositions will be tapped.

While the changing hydrocarbon content of PRUDHOE BAY natural gas may not be a major consideration in the design of ANGTS, system engineers do have to take into account the likelihood that gas produced from other, still undiscovered or undeveloped reservoirs on the North Slope may differ significantly in chemical composition. Prudhoe Bay gas is relatively sweet and wet (low in sulfur compounds and rich in NGL's), and has a relatively high CO_2 content. A conditioning plant designed to treat this raw gas stream, or a pipeline designed to carry it, would be uneconomic or even inoperable for gas from another reservoir which happened, for example, to be sour and dry, and contained little CO_2.

Under the present plan for ANGTS, the initial conditioning plant will be located on the North Slope and designed expressly to treat the volume and mixture of compounds the Prudhoe Bay reservoir is expected to produce. If new and different gas mixtures later came on stream from other reservoirs, the existing plant could be modified or new facilities added at the same place or elsewhere specifically to accommodate the new supply. In either case, the pipeline itself can be built to accommodate pipeline-quality (fully-conditioned) gas from any source in Arctic Alaska. If the conditioning plant were at Fairbanks or further downstream on the pipeline, however, system engineers would face the far more difficult task of designing both the pipeline and the conditioning plant to handle a stream of raw gas whose characteristics might change radically over time.

Thus, the possible need for ANGTS to handle different (and yet unknown) gas mixtures over its operating life is one reason why the gas producers, Northwest Alaskan, the prospective gas shippers, and FERC all seem to agree that the conditioning plant for Prudhoe Bay gas should be located on the North Slope, despite the belief of many Alaskans that construction and operating costs would be less, and local economic benefits greater, in an Interior Alaska location.

3. North Slope fuel requirements.

It takes a good deal of energy to produce, clean and condition, and transport oil and gas from the North Slope. This energy must be drawn out of the stream of produced hydrocarbons. There are three general categories of North Slope fuel uses: (1) FIELD FUEL, (2) TAPS FUEL, and (3) PLANT FUEL (for the gas conditioning plant).

(1) FIELD FUEL is needed for all of the activities relating to oil and gas PRODUCTION. In addition to actual oil production at the wells, energy is consumed in gathering the oil into facilities where the crude can be separated from the solution gas, dehydrated of its water content, and cleaned of its impurities. Field fuel is also consumed by the Prudhoe Bay electric generating plant. Produced gas in excess of fuel requirements is currently compressed to about 4000 psi for reinjection into the reservoir, pending the onset of gas sales. This function is performed in the Central Compressor Plant, which, likewise, requires a a good deal of energy.

Estimates of future field fuel requirements, such as those used in the Ralph M. Parsons Company report, must also provide for additional production activities, which will include more elaborate facilities for injecting back into the reservoir the produced water that is separated from the crude, and for the injection of source water from the Beaufort Sea in order to maintain reservoir pressure. (This is sometimes called waterflooding.) The "maximum" field fuel case used in the Parsons report takes all of these activities into account.

(2) TAPS FUEL is that which is needed to run the first four pump stations of the Trans-Alaska oil pipeline. While pump stations south of Station #4 provide for their own fuel

requirements by processing a portion of the crude oil into diesel fuel in individual topping plants, the TAPS owners decided that it would be cheaper to supply the more northerly pump stations with North Slope gas by means of a buried gas pipeline beside the oil line. Unlike the TAPS oil pipeline, the Alaska Highway gas pipeline will transport a mixture of hydrocarbons that can be used directly in its compressor stations, thus no provision has been made for supplying even its northern portions with a separate energy stream.

(3) PLANT FUEL is needed for all aspects of the gas conditioning process --- for (a) separating and fractionating propanes, butanes, and pentanes-plus from the lighter hydrocarbons; (b) for removing carbon dioxide from the remaining methane-ethane stream; and (c) for chilling and compressing the conditioned gas to meet the requirements for shipment through the gas pipeline. Sometimes PLANT FUEL is discussed more specifically as HEATER FUEL and TURBINE FUEL. The distinction is made because while heaters can run on a relatively low BTU fuel, turbines have more stringent requirements.

Where does all this fuel come from? Currently, the Field Fuel Gas Unit conditions a portion of the raw gas to provide energy for most ongoing field activities and for TAPS.[5] Since the TAPS fuel gas line experiences extremely cold temperatures enroute to the pump stations, the Field Fuel Gas Unit yields a gas stream with exceptionally stringent specifications --- a -40 degree F. hydrocarbon dewpoint and a -60 degree F. water dewpoint. When waterflooding begins, the Field Fuel Gas Unit can be expanded to

5) The gathering centers in the western part of the field furnish their own fuel.

accomodate the new demand. Or, as the Parsons study anticipates, additional FIELD FUEL requirements can be met by fuel generated at the conditioning plant. The Parsons study has chosen the latter technique in an attempt to optimize the entire system, disregarding ownership responsibilities. In so doing, an outlet is found for the ethane-rich CO_2 "waste" gas that is a by-product of the CO_2 removal process selected by Parsons. This stream is enriched with propane to provide a fuel suitable for field activities.[6]

Nevertheless, the producers make a point of emphasizing that they have several options for taking care of all their own fuel needs in the field and for TAPS, and they have not yet decided whether it would be in their interest to enter into an arrangement with the owner of the conditioning plant (whoever that may be) simply for the sake of overall project optimization. After all, their gas sales contracts commit for sale only the gas that is EXCESS to field and TAPS requirements. The producers further stress the potential disadvantages of making their crude oil production, processing, and transportation facilities dependent upon a stream of by-products from the gas conditioning plant. This concern would probably be even greater if the conditioning plant were operated and controlled by another party, such as the state.

Of course, the PLANT FUEL requirements will have to be met by the owners of the conditioning plant. Parsons Company, in its proposed plant design, has selected what it

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6) No one knows exactly how much field and TAPS fuel will be needed in the future. Moreover, those requirments will vary almost daily. Parsons, therefore, calculated both a "maximum" and a "minimum" field fuel case. Most parties believe the "maximum" case data is the more relevant for planning.

considers to be the most economical CO_2 removal process, given the raw gas composition and the probable gas pipeline specifications. The process chosen by Parsons, however, results in a waste gas that also contains about half of the ethane that enters the plant.[7] Accordingly, Parsons recommends using the ethane-CO_2 by-product for fuel. Given the fact that SOMETHING has to be burned as fuel, this is not necessarily a bad thing --- unless there is some reason to view the ethane (and the propane that enriches it) as exceptionally valuable hydrocarbons for which a better use exists. There is little argument within Alaska that ethane would be the most desirable feedstock for a local petrochemical industry. It is still unclear, however, whether an ethane based petrochemical plant is economically feasible in Alaska, and even if it were, whether all of the ethane would, in fact, be required for such a facility. For example, the November 1979 study prepared by Bonner & Moore Associates for the State of Alaska indicates that only about one-fourth of the ethane is needed to feed a "world-scale" petrochemical plant, in which case, the CO_2 removal process chosen by Parsons Company in itself should cause no alarm.[8]

One other major point of controversy arises with respect to design of the CO_2 removal process and PLANT FUEL requirements. The ethane-rich CO_2 waste gas has a lower heating value (net BTU) of about 200 to 220 BTU per cubic foot. While this mixture may be adequate for use in

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7) The Parsons design absorbs CO_2 via a physical, rather than a chemical, process. This process is much like fractionation in that the components are separated by their different boiling points. Given that the boiling point of ethane is relatively close to that of CO_2 (see Table 3), some of the ethane necessarily will "flash" off with the CO_2.

8) Bonner and Moore Associates, Inc., Promotion and development of the Petrochemical Industry in Alaska (November 1, 1979). See also the author's critical review of the Bonner and Moore report, "Prudhoe Bay Natural Gas Liquids, the Alaska Highway Gas Pipeline, and Petrochemical Development in Alaska" (January 20, 1980).

the plant heaters, it must be enriched to meet the specifications of the local turbines and field equipment. The Parsons Company design raises the BTU content by propane "spiking" to achieve a net heating value of about 475 BTU/cf for local turbine fuel, and 825 BTU/cf to suit the design limitations of existing field equipment. The controversy lies in the fact that while propane can easily be shipped south in the gas pipeline, butanes are more troublesome. Therefore, wouldn't it make more sense to use butane rather than propane for spiking purposes?

Unfortunately, the answer is not so simple. Butane could create the same hazards in the fuel system that it poses in the Alaska Highway gas pipeline --- condensation at low temperatures. In addition, its burning characteristics are different from those of propane, because it packs a bigger wallop of combustible carbons in each molecule. While use of butane instead of propane is not entirely out of the question, those responsible for smooth operations on the North Slope naturally will look for system designs and fuel compositions that promote simplicity and reliability. Unless the State of Alaska can demonstrate a special interest in the propanes or butanes that differs markedly from that shared by the other gas owners, any second-guesses the State might make with respect to fuel enrichment decisions would probably be viewed by others as unduly meddlesome.

Table 6 provides a perspective on North Slope fuel consumption. Of the hydrocarbons in the raw gas stream, about 15 percent will be consumed as field fuel, by the TAPS pump stations, and during the conditioning process.

TABLE 6

NORTH SLOPE FUEL REQUIREMENTS[1]

	Produced Gas[2]	FFGU Outlet[3]	Conditioning Plant Inlet	Field Fuel[4]	Plant Fuel[5]	Available Hydrocarbons[6]
Billion BTU/day (gross)	2849	[95]	2754	[214]	[113]	2427
Million cf/day	2700	[100]	2603	[236]	[248]	2104
Average BTU/cf (gross)	1055	953	1058	906	456	1154

NOTES:

1. Source: Exxon, personal communication (February 1980). Exxon personnel calculated these data using the Parsons reports maximum field fuel case.

2. An offtake rate of 2.7 bcf/day is assumed, consistent with the Prudhoe Bay reservoir field rules set by the Alaska Oil and Gas Conservation Commission. Parsons assumed a 2.8 bcf/day offtake rate.

3. FFGU Outlet signifies the fuel products of the Field Fuel Gas Unit that are used in the northern pump stations of TAPS and for a variety of field activities. Heavier hydrocarbons removed during that process are routed (along with the rest of the produced gas) to the conditioning plant and its fractionators.

4. Field Fuel designates those North Slope energy requirements that exceed the output of the Field Fuel Gas Unit. The present capacity of the Field Fuel Gas Unit is 100 million cubic feet per day. Parsons assumes that this capacity will be utilized fully, but that additional field fuel needs will be met by products of the conditioning plant, rather than by an expansion of the FFGU.

5. Plant Fuel includes both turbine and heater fuel for the conditioning plant. 456 BTU per cubic foot, therefore, represents the weighted average of the heating values for the relatively high BTU turbine fuel, and the low BTU heater fuel.

6. Available Hydrocarbons are the final product streams available for shipment through the gas pipeline or blended into TAPS crude.

4. Shipping intermediate hydrocarbons through TAPS.

As mentioned earlier, the Alaska Highway Gas pipeline will have no problem carrying light hydrocarbons (C_1, C_2, and C_3) in a vapor phase, while the TAPS oil pipeline can easily handle heavy hydrocarbons (C_6+) in a liquid phase. The question, then, is whether both systems together can support shipment of all of the intermediate hydrocarbons (C_4 and C_5) without encountering the hazards of two-phase flow.

Referring once again to Figure D, the reader will note that upset conditions attendant to a 1260 psig system limit the amount of butanes that can be transported through the Alaska Highway Gas Pipeline. The phase diagrams show that while 50 percent of the available butanes might be handled safely, shipping all of the available butanes would not be possible. Nobody can precisely judge what will constitute a safe limit, of course, until the pipeline engineering and contingency plans are completed. But it is clear that all of the pentanes and something less than half of the butanes will have to find another means of transport, such as TAPS.

Right now, crude oil enters the TAPS oil pipeline on the North Slope at 140 degrees F. Table 3 (on page 4) shows that at 140 degrees F., C_6 is a liquid but that C_5 and lighter hydrocarbons would be present in a vapor phase[9] What are the prospects for lowering the TAPS inlet temperature to enable it to accept all the pentanes and maybe even some of the butanes?

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9) The table, however, makes no provision for the fact that hydrocarbon MIXTURES can safely accomodate some small volume of light hydrocarbons which, as pure substances, would exist as vapors.

Most parties agree that the inlet temperature of TAPS can not feasibly be reduced below about 110 to 112 degrees F. Three factors account for this limitation:

(1) Even if the inlet temperature were reduced, say, to 100 degrees F., the warm summer months combined with the heat naturally generated by the friction of flow would result in somewhat higher temperatures in certain parts of the pipeline. Thus the temperature threshold that limits the introduction of intermediate hydrocarbons into the crude cannot effectively be reduced beyond about 100 degrees [Pritchard letter to Barlow; January 23, 1980].

(2) On the other hand, if the TAPS inlet temperature is reduced, the heavy components of the crude oil ("waxes") will solidify more readily, slowing the flow and thereby reducing the daily throughput. At lower inlet temperatures, the line will have to be "pigged" more often to strip away the wax build-up. Moreover, if inlet temperature specifications were relaxed, TAPS would face a greater risk that wax solidification might cause real problems if the line experiences an extended shut-down during the winter cold.

(3) Even if both of the previous limitations were ignored, there are practical constraints on the amount of intermediate hydrocarbons that can be shipped through TAPS. In order to control air pollution in the Los Angeles basin, government regulations permit no landing of crude oil with <u>vapor pressures</u> higher than 11.1 psia at storage temperatures of, say, 100 degrees F. That is, crude must emit no vapors when subjected to pressures at or above 11.1 psia and to temperatures at or below 100 degrees. Since the lowest pressure at which TAPS operates is around the atmospheric pressure of 14.7 psia, rather than 11.1 psia, a TAPS bubble-point specification compatible with California's standard would have to be somewhat above 100 degrees.

Given all three constraints just discussed, most parties seem to believe that a reasonable minimum inlet temperature for TAPS is about 110 to 112 degrees F. At that temperature, both ARCO [Dickinson letter to Tussing; January 3, 1980] and the Ralph M. Parsons Company [September 1978 study report, Volume II, page 2-271] believe that essentially all of the available pentanes and butanes could be transported through TAPS, at peak crude oil throughput rates. SOHIO, however, suggests that only some of the butanes can be accomodated [Pritchard letter to Barlow; January 23, 1980].[10]

Nevertheless, assuming that the gas pipeline can safely handle at least 50 percent of the available butanes as previous discussed,[11] there appears to be little chance that butanes will be stranded on the North Slope --- at least in the early years of gas shipments. As oil production declines, however, the ability of TAPS to carry intermediate hydrocarbons will drop accordingly. This decline is expected to occur much faster than the offsetting feature of a progressively "leaner" raw gas stream mentioned earlier. For example, assuming (1) a 1985 start-up for the gas pipeline, (2) ARCO's oil production forecast [Dickinson letter to Tussing; January 3, 1980], and (3) the Parsons' phase diagrams [Volume II, pp. 2-287, 2-297, of the September 1978 conditioning study], all of the "available" pentanes and butanes could be shipped through TAPS initially, but the oil line could no longer accept ANY butanes by the seventh year of gas shipments.

10) Before one focuses on the apparent disagreement, it must be remembered that all calculations to date have been rough and possibly based on different crude oil assays, or different decline rates for crude oil production. Sohio is scheduled to complete a more refined analysis of this matter in early 1980.

11) Most parties agree that it is realistic to assume that ANGTS can accommodate about 85 percent of the butanes available after removal of the various fuel streams in the Parsons' maximum field fuel case. The State believes, however, that if NO ethane or propane is burned on the Slope, and those hydrocarbons are instead shipped through the gas pipeline, only about 25 percent of the butanes could be accommodated in ANGTS.

Is there, then, any real cause for alarm? First, putting things in perspective, even in the early years of gas production when butane content is greatest, it will comprise less than 2 percent of the gaseous hydrocarbon volume (though about 5 percent of the total BTU content of the raw gas stream). Moreover, unless there is some reason to believe that the producers and their gas purchasers have less interest than the State in getting as many of the North Slope BTU's to market as possible, here too, it may be unreasonable for the State to make second-guesses on the best overall system design.