

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

1053 SCOMM 28: JOINT GAS PIPELINE COMMITTEE, 1981-82



ALASKA NATURAL GAS TRANSPORTATION SYSTEM

ROOM 2413, POST OFFICE BUILDING, 1200 PENNSYLVANIA AVENUE, WASHINGTON, D.C. 20044

August 13, 1981

No. 36

Federal Inspector Approves Affirmative Action Plan for

Alaska Gas Pipeline

John T. Rhett, Federal Inspector for the Alaska Natural Gas Transportation System, today announced approval of the affirmative action plan for employment and procurement for the 745-mile Alaska segment of the pipeline.

Approval of the Northwest Alaskan Pipeline Company plan followed several months of negotiation between the company and the Federal Inspector's staff.

The plan, which applies to the company, its contractors and subcontractors, sets goals for each of four minority groups and for females for each employment job group. Employment percentages by major job group for minorities and females for 1980 and 1981 are shown in the attached Fact Sheet.

The 1981 goal for minority business enterprise participation is \$31 million, or 15 percent of contractable opportunities, and \$4 million, or 2 percent, for female firms. Additional information on the goals is contained in the Fact Sheet.

An approved affirmative action plan covering both employment and procurement was required by regulations issued May 12, 1980, by the U.S. Department of the Interior. These comprehensive regulations, applicable only to the Alaskan gas pipeline project, required the sponsor's affirmative action plans be filed with and approved by the Federal Inspector.

The EEO regulations also require the sponsors to update their plan annually. These updates will adjust the goals, based on current information and anticipated level of project activity.

In light of the significant projected labor requirements of the Alaskan construction, a training task force has been organized, with representation from the Alaska State Pipeline Coordinator, the Alaska Department of Labor, the U.S. Department of Labor, the Office of the Federal Inspector (OFI), Northwest Alaskan Pipeline Company, organized labor, and Alaskan Native and minority organizations. This task force is currently Chaired by a representative of Northwest Alaskan Pipeline.

(more)

The task force will advise NWA on the planning and implementation of a training program to help people in Alaska qualify for work on the gasline project. The group will also provide a focal point for information that will help the Federal Inspector assure that the Federal affirmative action requirements are met. A total of 13,000 employees are expected to be working on the Alaska segment at peak construction, now estimated to be 1985.

The EEO/MBE regulations issued by the Department of the Interior allow preference for employment on the project be given to Alaskan Natives living on or near a reservation which is within commuting distance of any project activity, but only on that project activity.

Copies of the affirmative action plan for Alaska are available for inspection and copying in the Washington, D.C., Fairbanks and Anchorage Offices of the Federal Inspector.

-OFI-

For further information please contact:

Joyce R. Morrison
Washington Office
(202) 275-0586

Paul Steucke
Anchorage Office
(907) 271-3668

FACT SHEET

Northwest Alaskan Pipeline Company Affirmative Action Plan

Basic Facts on the Plan

The affirmative action plan (AAP) for the Alaska segment was filed September 2, 1980, by Northwest Alaskan; revised on December 11, 1980; and supplemented on March 2 and July 23, 1981, each time in response to requests by OFI. The affirmative action plan was approved by the Federal Inspector on August 10, 1981.

It totals about 600 pages and applies to all participants in the Alaska segment, including Northwest, its contractors and subcontractors. Some existing contractors must now file affirmative action plans for OFI approval. Excluded from the equal employment filing requirements are contractors with less than 50 employees or having a contract valued at less than \$50,000. Contractors having a contract of \$150,000 or more must submit an affirmative action plan for procurement, in addition to the employment plan.

Base information used by Northwest in formulation of its goals was 1970 Census information, updated to 1980.

Northwest will revise and update its affirmative action plan annually.

Employment

The plan contains employment goals for each year through completion of construction. However, because this information was based upon 1985-1986 project completion, the outyear goals will have to be revised to reflect the new schedule. The goals for 1980 and 1981 are shown below.

Average goal for operative or craft labor (except caterers) for 1980 was 17 percent for minorities. Of this 17 percent, 10.9 percent was for Alaska Natives.

The goal for female employment in the craft area was 7.02 percent during 1980.

1980 Employment

(Number of people employed by NWA, contractors, and subcontractors at end of 1980)

	<u>Male</u>	<u>Minority</u>	<u>Female</u>	<u>Total Minority & Female</u>
Officials and Managers	140	14	17	31
Professionals	448	45	50	95
Technicians	70	10	31	41
Clerical	38	11	109	120
Operative and Craft	179	26	14	40
Laborer	32	9	7	16

1981 Employment Goals

	<u>Minority (%)</u>	<u>Female (%)</u>
Officials & Managers	7.8	12.7
Professionals	9.4	8.7
Technicians	12.6	9.4
Clerical	20.0	45.6
Craft	14.9	2.9
Operatives	17.3	3.3
Laborers	21.5	5.5

Labor Force

Northwest is predicting that construction of the Alaska portion of the project will require a peak labor force of 13,000. Of these, about 9,650, or 70 percent, will be craft workers, operatives and laborers. Over 90 percent of this number will be provided by five unions: laborers (2,100); culinary workers (1,100); operating engineers (3,000); teamsters (2,000); and pipeline welders (1,000).

Contracting

The plan projects Minority Business Enterprise (MBE)/Female Business Enterprise (FBE) goals on an annual basis throughout construction. The goals are firm for 1980 and 1981, and projected for later years. The dollar goals are given in 1980 dollars and are based on a project cost estimate that is being reviewed by the Federal Energy Regulatory Commission. A detailed chart showing the contractable opportunities and goals is contained in the affirmative action plan. Because this chart was based upon a 1985-1986 project completion date, the specific out-year opportunities and goals will have to be revised to reflect the new schedule. A summary of the goals is given below:

<u>Year</u>	<u>Contractable Opportunities</u>	<u>MBE/FBE (Millions \$)</u>
Pre 1981	150	15
1981	208	35
Outyears (1982- completion)	<u>4.484</u>	<u>430</u>
TOTALS	\$4.842 billion	\$480 million

MBE/FBE Achievement - 1980

During 1980 the sponsor and its contractors made 1,359 procurement commitments, including 107 contracts. Of the commitments, 54 were to minority businesses and 134 to female businesses. The dollar value of these was:

Minority businesses - \$15.3 million or 22.7 percent
 Female businesses - \$2.8 million or 4.2 percent

These achievements are measured against actual contracts in 1980 of \$67,665,574.

1980 goals were:

Minority businesses - \$7.7 million or 12% of expected opportunities of \$64,000,000

Female businesses - \$2.6 million or 4% of expected opportunities of \$64,000,000

Total performance, from initiation of the project through 1980, measured against actual contracts valued at \$87,822,574 was:

Minority businesses - \$15,859,250, or 18.1 percent

Female businesses - \$3,356,711, or 3.8 percent

1981 Contracting Program

Total outside services planned for 1981 are \$217.6 million. Total contractable opportunities for 1981 are about \$208 million. Contract activity will be mainly in four accounts: temporary facilities, field programs, communications and supervisory control systems, and pipeline. The plan breaks out types of opportunities that might be available within these accounts.

1981 goals:

Minority businesses - \$31 million, or 15 percent of contractable opportunities

Female businesses - \$4 million, or 2 percent of contractable opportunities

Construction Information

Northwest has contracted with Fluor Corp. in Irvine, California, to be project manager for engineering, design, procurement and construction. In addition, they will have six general contractors or joint ventures, under fixed-price contracts, to perform the actual construction of the pipeline, as well as other major contractors to construct the compressor and metering stations and operations, maintenance, temporary and communication facilities. Northwest states that in the management of construction, substantial opportunities exist, particularly in the areas of quality compliance, affirmative action, and management information services. The key to significant minority and female participation in project construction is the extent to which such firms can joint venture with other companies. It has had success to date with this method of participation.

Training

Northwest's plan concludes that, based on current projections, pre-employment training will not be needed to meet estimated needs during the preconstruction and construction periods. On-the-job or classroom training of craft and clerical workers may be done during construction to ensure attainment of affirmative action goals.

It is expected that lower 48 labor markets will supply craft labor that the Alaskan market cannot supply. These trades will likely include operating engineers, plumbers and pipefitters, pipeline welders, and certain classifications of laborers.

Training will be given to selected personnel for the operational phase following completion of construction. The number of personnel required for operation will be small, however--less than 200.

Northwest has suggested that pre-employment training of craft workers by other organizations or agencies would be most useful if it were to occur the year prior to construction.

Alaskan Native Training

The Department of the Interior right-of-way permit to cross Federal lands is conditioned to require a company-sponsored pre-employment training program to help qualify Alaskan Natives for initial employment and for upgrading. The sponsors may either utilize existing training programs or develop their own program. It also requires an on-the-job training program for Natives. Further, the EEO regulations issued by the Department of the Interior allow preference in employment for Alaskan Natives living on or near land held by Native Corporations.

Monitoring and Enforcement

The Federal Inspector is responsible for assuring that Northwest is meeting the requirements of the regulations and its affirmative action plan.

In April 1981, the Federal Inspector issued enforcement regulations to assure that the sponsors comply with the Equal Opportunity Regulations and their affirmative action plans during construction of the U.S. portions of the 4,800-mile Alaska Natural Gas Transportation System. Both the law passed to expedite the project and the President's Decision selecting the system require minority and female participation in employment and procurement activities. Enforcement of the Equal Employment Opportunity Regulations, published in 1980, is the responsibility of the Federal Inspector. The enforcement regulations specify detailed OFI procedures which will assure sponsor, contractor, and subcontractor compliance with the sponsor's approved affirmative action plans. These procedures include complaint investigation, conciliation, and administrative and judicial tools.

Contact Points

Mr. Aaron Lovejoy
Manager, Affirmative Action
Northwest Alaskan Pipeline Company
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(714) 975-5651

Mr. John Alexander
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Office of the Federal Inspector
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Washington, D.C. 20044
(202) 275-0582

Mr. Roy Roehl
Equal Opportunity Specialist
Office of the Federal Inspector
1001 Noble Street
Fairbanks, Alaska 99701
(907) 452-1008

**PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT**



Office of the Federal Inspector

Alaska Natural Gas Transportation System

Room 2413, Post Office Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20044

AUG - 4 1981

Refer to:
D0002634

MEMORANDUM

TO: All Parties on the Restricted Service List
in Docket No. CP-80-435

FROM: J. Richard Berman *J. Richard Berman*
Director, Office of Audit and Cost Analysis

SUBJECT: Contacts with Northwest Alaskan Pipeline Company

The attached materials were received from Williams Brothers Engineering Company, summarizing all contacts between Williams Brothers and other parties to Docket No. CP80-435 since the last conference. This summary is being distributed to parties on the Restricted Service List in conformance with the notification procedures adopted in the conferences.

Attachments



RESOURCE SCIENCES CENTER | 6600 S. YALE AVE. | TULSA, OKLAHOMA 74177
PHONE (918) 496-5020 | TELEX 49-7493 WBEC-TUL

D. D. GRASSMAN
Vice President

Rec'd:sc:
AUG - 3 1981

31 July 1981

Office of the Federal Inspector
Room 2428, Post Office Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20044

Attention: Mr. J. Richard Berman
Director, Audit and Cost Analysis

OL-050-OFI

Dear Mr. Berman:

Attached is a summary of a contact between Williams Brothers Engineering Company and Northwest Alaska. This contact together with the group submitted to you under our Letter Number OL-045 dated June 19, 1981 and Letter Number OL-038-OFI dated May 19, 1981, constitute all the contacts between Williams Brothers and other third parties since the March Technical Conference.

Sincerely,

WILLIAMS BROTHERS ENGINEERING COMPANY

D D Grassman

D. D. Grassman
Vice President *by DCP*

DDG:DP:cb:4444
Attachment

WILLIAMS
BROTHERS
ENGINEERING
COMPANY

INTER-OFFICE CORRESPONDENCE

DATE

31 July 1981

SUBJECT: Contact With Northwest Alaska

TO: Del Grassman

COPIES:

FROM: Doyle Pierce

Rec'd: ac
AUG - 3 1981

On July 2, 1981, I called Cuba Waddington at NWA to advise him that we could not confirm the reconciled CCE numbers in Exhibit 9 (Rev.) submitted with the errata to the NWA Response on May 5, 1981.

The differences occurred in the following categories:

<u>Category</u>	<u>Exhibit 9</u> <u>(\$1,000)</u>	<u>WBEC Compilation</u> <u>(\$1,000)</u>
Temporary Facilities	909,148	908,538
Pipeline	4,273,787	4,274,550
Project Directorate	1,261,095	1,261,125

Cuba took down these numbers, said he would have a check made, and that NWA would issue an additional errata if necessary.



Doyle C. Pierce

DCP:cb



RESOURCE SCIENCES CENTER | 8800 S. YALE AVE. | TULSA, OKLAHOMA 74177
PHONE (918) 486-5020 | TELEX 40-7483 WSEC-TUL

Rec'd: sc:
JUN 25 1981

June 19, 1981

Mr. J. Richard Berman
Office of the Federal Inspector
Room 2428, Post Office Building
1200 Pennsylvania Ave., N. W.
Washington, D. C. 20044

Subject: Contacts with Northwest Alaska
OL-045-OFI

Dear Mr. Berman:

Enclosed are summaries of five contacts between Williams Brothers and Northwest regarding additional questions and answers on the NWA Response of May 1981.

In addition to these contacts, Williams Brothers was contacted by the Alaska State Pipeline Coordinator's Office (SPCO), including a meeting here in Tulsa. A summary of the Tulsa discussion was forwarded to you in our letter #OL-038-OFI dated May 19, 1981. Williams Brothers also attended a meeting in Irvine involving the OFI, NWA and Alaska SPCO. A summary of that meeting, which included some questions raised by us and answered by NWA, was included in NWA's comments dated June 2, 1981.

This letter summarizes pertinent contacts, between Williams Brothers and other parties to the proceedings, which have occurred since the March Technical Conference.

Very truly yours,

WILLIAMS BROTHERS ENGINEERING COMPANY

D. D. Grassman

D. D. Grassman
Vice President

DDG:DP:rh:4444
Enclosures

cc: Cuba Wadlington, NWA

1981 JUN 25 11 50 AM
FEDERAL INSPECTOR
OFFICE OF

**WILLIAMS
BROTHERS
ENGINEERING
COMPANY**

INTER-OFFICE CORRESPONDENCE

DATE

April 10, 1981

NWA CCE Job 4444-804

**SUBJECT: Compressor & Metering Stations
NWA Vendor Bid Review**

TO: Del Grassman

**COPIES: ~~Doyle Pierce~~
J. S. Atkins**

FROM: William E. Bailie

Rec'd: ac:
JUN 25 1981

The review of the vendor bids received from NWA and Fluor for the mainline gas compressors, refrigeration units and station power generator units was completed 4/8/81. Several questions developed from the vendor bid review and comparing the NWA data provided in the CCE for price averaging sheets. The price averaging sheets - Mainline compressors, page 369; refrigeration units, page 368 and power generator units, page 370 of Vol. 17 - were utilized in the vendor bid review. An attempt was made to reproduce NWA's figures and in a few instances we were able to do it. A list of questions was prepared which would aid us in determining just which bids were used etc. in the price averaging of the three major compressor station items. The list of questions are attached. Doyle Pierce called Cuba Wadington at Irvine and mentioned our questions and Cuba was to arrange for Bob Olson, Fluor to call us and answer or obtain answers to our questions.

Bob Olson, Lou Losorodo and Fritz Cromiller called this morning at approximately 10:15 a.m. I read each question one at a time and Olson or the other two gentlemen responded to it. The following is the verbal data received from Fluor on the subject.

- Question #1. Bob Olson said there were work sheets made for the price averaging of the mainline compressors and refrigeration units. He would see that Cuba is given copies of them to be handled with us. These work sheets are similar to those we were furnished for price averaging of the station power generator units.
- Question #2. Bob Olson mentioned which vendor bids were used in their price averaging.

- Question #3. Lou Losorodo mentioned that in Vol. 14 page 39 the freight was removed from the mainline gas compressor average cost and on page 250 same was done to the station power generator unit average cost. I have reviewed those pages and found that the ocean freight was removed @ \$20,500 from the mainline compressor average cost of \$5,042,900. The figures are both different from those that are included in price averaging summary sheet page 369 Vol. 17, which are \$5,038,857 per unit and averaged freight of \$20,425. The differences in figures represents \$3,968 per unit or \$27,776 total higher in the CCE than necessary. When reviewing the power generator page 250, different figures were again used. Page 250 had \$2,642,900 averaged station generator (2) unit cost less \$700,000 per station for waste heat package removal and \$25,000 per station for ocean freight. From Vol. 17 page 370 price averaging summary sheet for power generator units the following are \$2,640,571 average price for generators units complete per station including \$700,000 for waste heat package and freight @ \$25,155 per station. The difference in these figures represents \$2,484 per station or \$17,388 total higher in the CCE than necessary. The above differences are not great but they do add up to increase the CCE. These also indicate the type of minor arithmetic and posting errors that are spotted throughout the CCE.
- Question #4. The engineering fee as requested to be itemized separate in the vendor bids are supposed to be included in the price averaging per Lou Losorodo but he could not verify that they were. There is no mention or costs included for vendor engineering fee in the price averaging summary sheets for the mainline compressors, refrigeration units or power generator units.
- Question #5. Several responded to this question but Bob Olson summed up the response. Fluor used 210 Yen/U.S. \$ for one bid and 237 Yen/U.S. \$ for the other Japanese bids. No exchange rate or conversion was made for Swiss Francs or German Marks since those bids were not used in Fluor's price averaging work. I would like to mention Fluor used 245 Yen/U.S. \$ in their price averaging work sheets for the power generator units. This does not correspond to what Fluor just

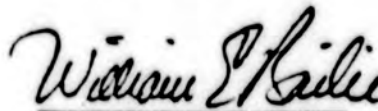
provided and no reason given why two different exchange rates were used as mentioned above (210 and 237 Yen/U.S. \$).

We discussed the different freight costs estimated for the mainline gas compressors. I asked why such a difference since all four manufacturers are in the same general section of the country or are very close to each other. No real reply was made but Olson said it did appear to be strange, one being at least three times the others. We also discussed the vendor's price used in the price averaging being too low. The way I read it, the price should be \$128,117,920 as quoted. Fritz is to look into the matter - it may be a difference of interpretation!

I asked Bob Olson if they were going to provide or furnish us any additional material or data to support their position relative to matters discussed during the conference here late March. He said Fluor was preparing the data they propose to furnish us. The data was to be printed over the weekend and would be submitted to NWA first of next week. Bob could not state when we would receive it, if any of it. He said it was up to NWA to decide. I said, "Fine," and that I was only incurring so I could possibly schedule my work to accommodate it. I thanked him for his information that he provided.

I guess if we are to receive any follow-up data from NWA, it most likely will be received late next week at the earliest.

Respectfully,


William E. Baillie

WEB:cb:3356
Attachments

General Questions relative to NWA Vendor bid review.

- ① Are there any NWA work sheets available that were used to develop the price averaging cost sheets for mainline gas compressors and also refrigeration units? There were work sheets available for the price averaging cost sheet for station power generator units.
- ② Which vendor quotes were either used or not used?
- ③ Why was freight included in the price averaging for mainline gas compressors and station power generator units and not for refrigeration units?
- ④ Why was the engineering fee requested as separate item and NOT used in any of the price averaging work?
- ⑤ What foreign currency exchange rates used to convert Japanese Yen (¥), Swiss Francs (Sfr) and German Marks (DM) into US dollars?

FERC FILING

ESTIMATED COSTS

Mainliners	Vendor J	Vendor K	Vendor L	Vendor M
Gas Generator	RB-211	RB-211	LM-2500	LM-2500
Base Price - each -	\$ 4,960,000	\$ 4,270,000	\$ 4,093,946	\$ 4,561,000
API Lube-Seal				
Oil Console			75,000**	75,000
w/air cooled				
Accoustical Enclosure Included	Included	Included	Included	Included
w/Halon system				
Pre-heating inlet	Not	Not		
air filter	Required	Required	84,000**	84,000
Compressor w/side	200,000			
inlet and exhaust	\$ 200,000	Included	Included	Included
Local Control Panel	Included	Included		Included
Performance and String				
Testing	\$ 150,000**	\$ 200,000	\$ 150,000**	\$ 140,000
Long Term Storage	Included	Included	9,000**	8,720
Total	\$ 5,310,000	\$ 4,470,000	\$ 5,221,946	\$ 4,928,700
Each x 7 units	\$37,170,000	\$31,290,000	\$36,554,000	\$34,500,000
Seismic Qualifications	250,000**	250,000**	250,000**	250,000**
Freight - Estimated from				
Purchasing	329,000	105,000	90,000	47,890
TOTAL	\$37,749,000	\$31,645,000	\$36,894,000	\$34,797,890

AVERAGE \$35,272,000

Notes -

(a) All pricing FOB Manufacturer's plant

(b) ** Estimated data

Freight \$142,973
7,420,425

JUN 6 1980

PRICE AVERAGING
INQUIRY NO. 0704-4-468086
14 REFRIGERATION UNITS

Vendor D	\$ 86,856,000	
Vendor E	\$103,167,400	
Vendor F	^{103,117,920} <u>\$100,067,820</u>	<i>carrier + spare part avg fee.</i>
Average	\$ 96,697,073	
Full Performance Test by Vendor F	<u>\$ 28,050,100</u>	<i>carrier</i>
TOTAL	\$124,747,173	

- Notes:
- 1) Vendor G was eliminated from price averaging due to lack of competitiveness.
 - 2) Vendor H was eliminated due to questionable credibility of their bid.
 - 3) Vendor I was eliminated due to noncompliance with the specified requirement for unit responsibility.
 - 4) Prices quoted are all F.O.B. Factory.

JUN 6 1980

C-O-N-F-I-D-E-N-T-I-A-L

FERC FILING

ESTIMATED COSTS

Gas Turbine Generators	Vendor N	Vendor O	Vendor P	Vendor Q
	Single Shaft	Single Shaft	Two Shaft	
For 14 units				
Base Price w/Lube System in Base Gear & Generator	11,763,850	13,001,777	12,892,200	13,149,822
Accoustical Enclosure w/Halon System	Included	Included	Included	Included
Inlet Air Filter	Included	Included	Included	Included
Waste Heat Boilers (14 units)	4,900,000	4,900,000	4,900,000	4,900,000
w/Exhaust Silencer w/Supplemental Firing - (Per Vendor AC Quote Quote)	From Vendor AC Quote			
Local Control Panel	210,000	Included	350,000	210,000
Add to bring up to Job Req-Estimated				
Electro Hydraulic Start	Included		Included	Included
Dual Fuel	Included		Included	Included
Lube Oil Cooler	Included			Included
Spare Fan Installed	52,000*	52,000*	52,000*	52,000*
Long Term Storage	70,000*	70,000*	70,000*	70,000*
Diesel Day Tank, Pump and Filter	140,000*	140,000* Estimated	140,000*	140,000*
Full Load Performance Test (14 Tests) ea.	Included Included	Included Included	Included Included	Included 280,000
Total	17,135,850	18,163,777	18,404,200	18,801,822
Estimated Freight From Purchasing	294,000	140,000	150,000*	120,351
Seismic analysis/Tests	180,000	180,000*	180,000*	180,000
Total	17,615,850	18,483,777	18,734,200	19,102,173

Average

18,484,000 → 2,640,571 per station

*Estimate

(the freight 176,000 incl → 25,155 per station)

Exhibit VI

**JUN 6 1980
370**

CLIENT

NORTHWEST ALASKAN PIPELINE

CONSTRUCTION COSTS

FLUOR

LOCATION

ALASKA

C.O. NO. 478024 JOB NO.

PROJECT

ALASKAN GAS PIPELINE

AREA-UNIT 22 - ON

MADE BY FEATHERSTON APVD.

A/C NO.	ITEM & DESCRIPTION	QUAN.	UNIT	MANHOURS			COST/UNIT			COSTS (\$)			
				PER UNIT	TOTAL	RATE	LABOR	SUB CONTR.	MAT'L	LABOR	SUB CONTRACT	MATERIAL	TOTAL
41	-06-TK-2 RAW WATER STORAGE TANK LESS OCEAN FREIGHT @ 90% NET WEIGHT SIZE	1	EA								47010		
43	-07-MG-1 ELECTRICAL GENERATION PKG LESS WASTE HEAT RECOVERY PACKAGE (SEE 45 AK) SUBTOTAL LESS OCEAN FREIGHT NET INCLUDING MH/HP → (43 AK CHART) TURBINE GENERATOR SKIDS	1 <27	EA EA		1350			2142,900				2142,900 <707,000> 1,991,900 <25,000> 1,917,900	
	-07-MG-1-G-1 A,B ELECTRICAL GENERATORS	2	EA		150								
	-07-ME-1-GT-1 A,B GAS TURBINE DRIVERS 3830 HP												
	-07-ME-1-GT-1 AC, BC AIR COMPRESSORS												
	07-MG-1-F-2 FUEL GAS FILTER												
	SKID WEIGHT 50000 lbs EA. SIZE 28' x 9' x 10' H L.W.H = 2520 CF (Y)												

250

PRINTED IN U.S.A.

DATE 4-3-80

REVISION NO. 1

REVISION DATE 5-9-80

CODE

PAGE NO.

FORM E-191A REV. 11/72

CLIENT NW-H

CONSTRUCTION COSTS

FLUOR

LOCATION ALASKAC.O. NO. 478021 JOB NO. _____PROJECT ALASKAN GAS PIPELINEHSEH - UNIT 22-01MADE BY EGATHERS APVD. _____

A/C NO.	ITEM & DESCRIPTION	QUAN.	UNIT	US MANHOURS		COST/UNIT			COSTS 1980				
				PER UNIT	TOTAL	RATE	LABOR	SUB CONTR.	MAT'L	LABOR	SUB CONTRACT	MATERIAL	TOTAL
43	PIPELINE GAS COMPRESSOR PACKAGE INCLUDING: LESS OCEAN FREIGHT NET MH/HP → (43 AK CHART) COMPRESSOR SKID: -01-C-1 PIPELINE COMPRESSOR -01-C-1 PIPELINE COMPRESSOR GAS TURBINE DRIVER SKID WEIGHT: 175,000 lbs SIZE 45' X 12' X 12'H L.W.H = 6480 CF (Y) PUMP SKID: -01-C-1-P-1 A,B COMPRESSOR LUBE OIL PUMP -01-C-1-P-2 A,B COMPRESSOR SEAL OIL PUMP -01-C-1-P-3 A,B TURBINE LUBE OIL PUMP SKID WEIGHT 25,000 lbs SIZE 30' X 12' X 8'H AN OVERHEAD SEAL OIL TANK WEIGHT 1224 lbs SIZE 12' X 30' X 1' 6" H MH/L.D → (42 AK CHART) AN OVERHEAD LUBE OIL TANK WEIGHT SIZE 24" X 6" MH/L.D → (42 AK CHART)	1	EA		3000	✓			504290			504290	
												<20,500> 5,022,700	
		1	EA (Y)		150								
		1	EA (Y)		80								
		1	EA		20								
		1	EA		10								

PRINTED IN U.S.A.

DATE 4-2-82 REVISION NO. 1 REVISION DATE 5-9-80 CODE _____ PAGE NO. _____

FORM E-193A REV. 11/79

WILLIAMS
BROTHERS
ENGINEERING
COMPANY

INTER-OFFICE CORRESPONDENCE

DATE

May 8, 1981

115. (812)

SUBJECT: Questions asked of NWA and Fluor pertaining
to the NWA response and the CCE.

TO: Del Grassman

COPIES: D. Pierce
OFI File ✓

FROM: Jeff Wenzell

The following is a list of questions which were addressed to NWA and Fluor representatives followed by the answer to each question. The questions and answers are summarizations of the pertinent information received through telephone conversations of April 27 through April 29, 1981.

1. (Q) Response Volume I and Volume III, as relating to revegetation materials, do not appear to be using identical logic. Which is correct?

(A) Volumes I and III were written separately, Volume I uses "Means" for reference while Volume III was developed using unit prices and specified application rates.

There may be additional information regarding the two approaches provided in the near future.

2. (Q) Were the revegetation material application rates supplied by the environmentalists?

(A) No, for the mulch and fertilizer. These are as specified in the filing, but were considered appropriate by sub-contractors who were contacted for quotes.

For the seed, the native grass mixture was specified by the environmental people as was the \$16.00 per pound price for the mix.

3. (Q) Were the unit prices for the materials estimated or are they quotes?

(A) The unit prices are based on the revegetation sub-contractors quotes. Two were contacted.

Page 2

4. (Q) How was the \$75.00 per acre for watering after seeding computed?
- (A) It is an estimated cost for providing irrigation pipe, sprinklers, pumps, etc., to keep the new seed wet in order to establish roots. This is required by the state of Alaska.
5. (Q) Was the 20% loss and waste factor for revegetation materials obtained from the revegetation sub-contractors?
- (A) Yes, they indicated 20% would be a percentage they would use to account for loss and waste of material.
6. (Q) Which of the two revegetation material analysis contained in the NWA response were used in the summary for adjusted costs?
- (A) I believe the costs contained in Section 6 of the response were used in the adjusted costs.
7. (Q) There was no material site stripping quantity shown for Atigun Pass in the NWA response Section 6. Is this correct?
- (A) No, these were inadvertently left out of the response. The correct volume of material site stripping quantity for Atigun Pass is as shown in the CCE, that is 5,000 bcy. This figure is a prorated portion of the total Section II material site stripping volume attributable to the Atigun Pass work. The section quantities shown in the CCE are for information only and do not represent the actual amount of stripping required for Atigun Pass.

Page 3

8. (Q) What does the term, "Compacted Material on Embankment" specifically refer to as used on pages 6-34, 6-35 and 6-36 of the NWA response?
(Reference workpad and access road maintenance.)

(A) It is the neat quantity of embankment material provided by Engineering.

9. (Q) Does "Compacted Material on Embankment" include the workpad and access road embankment quantities?

(A) Yes.

10. (Q) The moves as used in Section 6 of the response for workpad and backfill crushing refers to the moving from one site to another, is this true?

(A) Yes.

11. (Q) What is the water truck to be used for in the backfill crushing operation?

(A) The water truck was included by the EC's and we believe it will be used for plant cooling water and dust control around the material site.

12. (Q) Why are two dozers applied to feeding the workpad crushing equipment while only one is applied to feeding the backfill crushing equipment?

(A) The workpad crushing equipment is operating at 500 tons per hour while the backfill crushing equipment operates at 300 tons per hour. The two dozers are required to provide adequate material for the workpad crushing operation while one dozer will be adequate to supply material for the backfill crushing operation.

Page 4

13. (Q) Why was one 773 (50 Ton) end dump used in feeding the workpad crushing equipment which operates at 500 tons per hour, while two 769 (35 Ton) end dumps were used to supply the backfill crushing equipment which operates at only 300 tons per hour?

(A) The material for the workpad crushing operation will be obtained from an area closer to the crushing equipment than the material for use in the backfill crushing operation. The additional haul distance associated with feeding the backfill crushing equipment necessitates two 769 end dumps.

14. (Q) What is the determining factor that determines the hourly production rate for the workpad and backfill crushing equipment?

(A) The bare production rates of 500 tons per hour and 300 tons per hour were supplied by the EC's based on their experience in Alaska.

15. (Q) What does the quantity for thermal degradation represent in workpad and access road maintenance?

(A) The thermal degradation quantity is for excess workpad embankment material that will be required where the toe of the haul road embankment has subsided due to thermal erosion.

16. (Q) How were these quantities estimated?

(A) The Michael Baker engineers identified problem areas from the aerial photographs, then determined quantities based on field investigations.

Ψ FLUOR ENGINEERS AND CONSTRUCTORS, INC.

SOUTHERN CALIFORNIA DIVISION

3333 MICHELSON DRIVE
IRVINE, CALIFORNIA 92733
TELEPHONE: (714) 975-2200
TELEX: 80-2488

May 12, 1981

Fluor Contract 4680

Williams Brothers Engineering Company
6600 South Yale Avenue
Tulsa, Oklahoma 74136

Attention: Jeff Wenzell

Re: Additional WBEC Questions Concerning CCE

Jeff,

The following comments have been prepared in response to your telex of 5/5/81.

These comments correspond numerically to the questions on the attached telex.

1. The alignment sheet quantities for spoil disposal from the workpad do not include access road disposal quantities. The CCE does not include any quantities for access road disposal, however, if there were any, the disposal material would be stored along the access road and no hauling would be required.
2. The right-of-way losses associated with select and common backfill material were not considered in connection with the workpad maintenance quantities. During construction, the majority of the workpad and access road maintenance material will be required prior to the back filling operation. Additionally, the CCE is based on stockpiling or wind rowing the back fill material along the working side of the ditch and not back on the workpad. Therefore, the material coming into contact with the ground surface is not recoverable and can not be utilized for maintenance.

All maintenance material will come from either excess useable ditch excavation or from nearby material sites.

3. No, the ditch dimensions used to calculate the excavation quantities were established by PMC estimating personnel with the consensus of the EC's.

Williams Brothers Engineering Company
Attention: Jeff Wenzell

May 12, 1981
Page 2

4. Yes, the operation was estimated on the basis that the crushing plants would be dismantled, moved and erected during the day. The day crews assigned to the crushing operations will be either involved in the moving operation or in preparing the new location. However, the night crews or second shift crews will be waiting for the plants to be moved. Therefore, two shifts per moving day were estimated to account for the moving time of the first shift and the waiting or lost time of the second shift.
5. I am assuming that your first statement comes from the General Notes, No. 1 of the Typical Ditch Configurations shown in the Design Manual. As is quite apparent from the quantity of bedding and padding material calculated by Engineering, they did not adhere to this statement. This was a very preliminary note and was never used for the estimating of bedding and padding material either by Engineering or by PMC estimators. Engineering actually figured that all ditch would require bedding and padding and that all bedding and padding material, except in a few site specific areas of Type I ditch, would come from material sites. In a few areas of Type I ditch, they did figure that in situ material would be suitable for bedding and padding.

Engineering did not include a right-of-way loss for excavated material reused as backfill because they assumed that this loss would be taken care of by the excess excavated material.

The allowance provided by PMC for right-of-way loss is based on construction experience. Ditch spoil, if reusable, will be placed on the off-side of the ditch on a non stripped right-of-way. Spoil material coming into contact with the ground surface is not recoverable and cannot be utilized for back filling the ditch. This material will be regraded during restoration.

6. The civil progress schedule is applicable to the total material site operation.
7. This is an error. No material site losses should be applied to common material that is being reused from ditch excavation.

✓ FLUOR

Williams Brothers Engineering Company
Attention: Jeff Wenzell

May 12, 1981
Page 3

8. The asterisks were put there originally as reference to a footnote which stated that those unit quantities contained errors in calculation. If corrected, the numbers should read as follows: Common - Total 1.57, 1.47, 1.47, 1.38, 1.47, 0.71, 2.87, 3.72, 4.62, 5.57, 6.57, 2.30, 2.44, 2.57, 2.70 and 2.83. Select-Total 2.13, 2.05, 2.13, 1.92, 2.05, 1.78, 2.49, 2.49, 2.49, 2.49, 2.49, 3.15, 3.90, 4.70, 5.55 and 6.44. These corrections would change the Common-Total from 6,624,754 to 7,100,785 and the Select-Total from 8,676,731 to 9,274,935.

Based on the fact that the CCE is only an estimate and has numerous variables, it was decided that these corrections would not be made. However, if you wish to make these corrections at this time, NWA/PMC has no objection.

9. The major reason that the material was not used as back fill is that it would not be cost effective to do so. If common material could be obtained from a nearby material site and hauled to the right-of-way at less cost than hauling excavated material a long distance along the right-of-way, the excavated material was not used. The majority of this excess excavated material (2,000,000 + BCY) is used for maintenance and the remainder is used for restoration.
10. Yes they were (Refer to No. 9)
11. No it will not. Normally, the hauling units will take the aggregate directly from the bin and will not require a loader for loading. However, a loader or a dozer will be required to bulk-up the material into stockpiles after the haul units have dumped the aggregate. A loader was used in lieu of a dozer because of its increased mobility and wider use potential.
12. The CCE is based on the assumption that the material will be windrowed along the right-of-way. This windrow is estimated to have an average base width of 8 LF. The bottom 6 inches of material in this windrow will not be recoverable. The following calculation was used: $0.14 \text{ BCY/LF} = \frac{7' + 8'}{2} \times .5' \times 1$.
- 27
- The 0.05 BCY/LF shown on the flow sheet represents an average loss along the entire pipeline length for common material obtained from material sites.

Y FLUOR

Williams Brothers Engineering Company
Attention: Jeff Wenzell

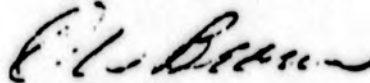
May 12, 1981
Page 4

13. The berm material over the Type II A ditch is common material. There has been no differentiation between common backfill material and the workpad material in the estimate.
14. The D.D.P.'s were developed by Engineering for the entire length of the pipeline.

These D.D.P.'s were used by Engineering for estimating their excavation quantities. PMC estimators did not use these. The ditch cross sections were revised and the excavation quantities determined utilizing the March Charts and construction experience.

15. Refer to No. 14 above.
16. That is correct. Refer to No. 5

Very truly yours,



D. W. Brown
Project Controls Manager


DWB:RL:km

444-812
May 13, 1981

SUBJECT: Questions asked of Fluor and NWA pertaining
to the NWA response and the CCE.

TO: Del Grassman

COPIES: D. Pierce
OFI File ✓

FROM: Jeff Wenzell

Jeff Wenzell
The following are questions addressed to NWA by phone on April 30, 1981. When there was no response from Fluor by May 5, 1981, I called and found out NWA had not notified Fluor of the questions (as NWA had told me they would). The questions were then addressed to Fluor by telephone and confirmed by telex on May 5, 1981. The response to these inquiries were received May 13, 1981 by telecopy. The questions from the telex and the answers from the telecopy are listed below:

1. Do the alignment sheet quantities for spoil disposal from workpad also include access road disposal quantities?

A The alignment sheet quantities for spoil disposal from the workpad do not include access road disposal quantities. The CCE does not include any quantities for access road disposal, however, if there were any, the disposal material would be stored along the access road and no hauling would be required.
2. Were the select and common R.O.W. loss quantities considered in connection with workpad maintenance quantities? Are the R.O.W. losses credited towards maintenance?

A The right-of-way losses associated with select and common backfill material were not considered in connection with the workpad maintenance quantities. During construction, the majority of the workpad and access road maintenance material will be required prior to the back filling operation. Additionally, the CCE is based on stockpiling or wind rowing the back fill material along the working side of the ditch and not back on the workpad. Therefore, the material coming into contact with the ground surface is not recoverable and can not be utilized for maintenance.

All maintenance material will come from either excess usable ditch excavation or from nearby material sites.

NWA Response

Page 2

3. Did the E.C.'s provide the excavation dimensions?

A No, the ditch dimensions used to calculate the excavation quantities were established by PMC estimating personnel with the consensus of the EC's.

4. Backfill crushing plant move times are in days then doubled for two shifts per day. Is this correct?

A Yes, the operation was estimated on the basis that the crushing plants would be dismantled, moved and erected during the day. The day crews assigned to the crushing operations will be either involved in the moving operation or in preparing the new location. However, the night crews or second shift crews will be waiting for the plants to be moved. Therefore, two shifts per moving day were estimated to account for the moving time of the first shift and the waiting or lost time of the second shift.

5. Engineers estimated only 25% of ditch would require bedding and padding and common backfill would only be used at site specific locations.

They did not include R.O.W. losses into their volumes of material to be reused from the ditch excavation. The CCE estimated R.O.W. losses for common backfill material reused from the ditch excavation, why?

A I am assuming that your first statement comes from the General Notes, No. 1 of the Typical Ditch Configurations shown in the Design Manual. As is quite apparent from the quantity of bedding and padding material calculated by Engineering, they did not adhere to this statement. This was a very preliminary note and was never used for the estimating of bedding and padding material either by Engineering or by PMC estimators. Engineering actually figured that all ditch would require bedding and padding and that all bedding and padding material, except in a few site specific areas of Type I ditch, would come from material sites. In a few areas of Type I ditch, they did figure that in situ material would be suitable for bedding and padding.

NWA Response

Page 3

Engineering did not include a right-of-way loss for excavated material reused as backfill because they assumed that this loss would be taken care of by the excess excavated material.

The allowance provided by PMC for right-of-way loss is based on construction experience. Ditch spoil, if reusable, will be placed on the off-side of the ditch on a non stripped right-of-way. Spoil material coming into contact with the ground surface is not recoverable and cannot be utilized for back filling the ditch. This material will be regraded during restoration.

6. Is the civil progress schedule on page 6-18 of the NWA response just for material site operation associated with select backfill material or is it for the total material site operation?

A The civil progress schedule is applicable to the total material site operation.

7. Why are material site losses considered for common material being reused from ditch excavation?

A This is an error. No material site losses should be applied to common material that is being reused from ditch excavation.

8. What do the *(asterisks) mean in the backfill quantities for common and select backfill in the excavation and backfill summary prepared by Fluor on 11-18-80, in response to trail staff's comments?

A The asterisks were put there originally as reference to a footnote which stated that those unit quantities contained errors in calculation. If corrected, the numbers should read as follows: Common - Total 1.57, 1.47, 1.47, 1.38, 1.47, 0.71, 2.87, 3.72, 4.62, 5.57, 6.57, 2.30, 2.44, 2.57, 2.70 and 2.83. Select-Total 2.13, 2.05, 2.13, 1.92, 2.05, 1.78, 2.49, 2.49, 2.49, 2.49, 2.49, 3.15, 3.90, 4.70, 5.55 and 6.44. These corrections would change the Common-Total from 6,624,754 to 7,100,785 and the Select-Total from 8,676,731 to 9,274,935.

NWA Response

Page 4

Based on the fact that the CCE is only an estimate and has numerous variables, it was decided that these corrections would not be made. However, if you wish to make these corrections at this time, NWA/PMC has no objection.

9. Why are 2,000,000+ bcy of useable ditch excavation not used for backfill?

A The major reason that the material was not used as back fill is that it would not be cost effective to do so. If common material could be obtained from a nearby material site and hauled to the right-of-way at less cost then hauling excavated material a long distance along the right-of-way, the excavated material was not used. The majority of this excess excavated material (2,000,000 + BCY) is used for maintenance and the remainder is used for restoration.

10. If the material will be used for maintenance, were the material site maintenance quantities adjusted by this amount? (refer to question #9)

A Yes they were (Refer to No. 9)

11. Won't the use of the 50 ton aggregate bin with conveyor in the workpad crushing operation negate the need for a 988 loader to stockpile product?

A No it will not. Normally, the hauling units will take the aggregate directly from the bin and will not require a loader for loading. However, a loader or a dozer will be required to bulk-up the material into stockpiles after the haul units have dumped the aggregate. A loader was used in lieu of a dozer because of its increased mobility and wider use potential.

12. How was the .14 bcy per LF of common R.O.W. losses estimated? The flow sheet indicates .05 bcy per LF.

A The CCE is based on the assumption that the material will be windrowed along the right-of-way. This windrow is estimated to have an average base width of 8 LF. The bottom 6 inches

NWA Response

Page 5

of material in this windrow will not be recoverable. The following calculation was used: $0.14 \text{ BCY/LF} = \frac{7'+8'}{2} \times .5' \times \frac{1}{27}$.

The 0.05 BCY/LF shown on the flow sheet represents an average loss along the entire pipeline length for common material obtained from material sites.

13. Is the berm material over the type IIA ditch, common backfill or workpad material? Is there a difference?

A The berm material over the Type II A ditch is common material. There has been no differentiation between common backfill material and the workpad material in the estimate.

14. The design manual refers to "Ditch Degradation Potentials", in terms of: the time of year the ditch is open, the soils, the ground water table, and the thermal condition.

Were these D.D.P.'s developed for the entire pipeline and were they used during the estimation of trench excavation?

A The D.D.P.'s were developed by Engineering for the entire length of the pipeline.

These D.D.P.'s were used by Engineering for estimating their excavation quantities. PMC estimators did not use these. The ditch cross sections were revised and the excavation quantities determined utilizing the March Charts and construction experience.

15. If not, what factors were primarily considered?

A Refer to No. 14 above.

16. The estimate of backfill quantities considers that no usable ditch excavation will be 2 inch minus material suitable for use as bedding and padding, correct?

A That is correct. Refer to No. 5.

WILLIAMS
BROTHERS
ENGINEERING
COMPANY

INTER-OFFICE CORRESPONDENCE

DATE

4/44-812
May 19, 1981

SUBJECT: Additional Questions Asked Of Fluor And NWA
Concerning The NWA Response And The CCE.

TO: Del Grassman

COPIES: D. Pierce
OFI File ✓

FROM: Jeff Wenzell
Jeff Wenzell

The following list contains five additional questions addressed to Fluor on May 14, 1981 and answers received May 18, 1981. These questions concern civil crushing and backfill quantities.

1. Why were no costs included in the NWA Response, page 6-6, for Atigun Pass work pad crushing?

A The NWA Response was prepared based on the format of the WBEC Report. In the WBEC Report Atigun Pass is included at the back of the report, not with Section 2, and for this reason was overlooked. The costs for Atigun Pass should have been included.

2. Why were no costs included in the NWA Response, page 6-14, for Atigun Pass select backfill crushing?

A Refer to No. 1.

3. Why does the total select backfill crushing operation manufacture 10,109,000 bcy while the total select backfill material hauled only equals 8,677,000 bcy?

A The difference in quantities comes from plant waste, or loss during crushing and a buffer allowance in case of an overrun of the estimated amount of select backfill. An allowance of 22 percent was made for this item; but because some select material is available, which does not require crushing, the overall average allowance was reduced to approximately 17 percent.

4. How was the quantity of extra material calculated? (Refer to 3)

A Refer to 3.

May 19, 1981
Page 2

5. Refer to your comments of May 12, 1981 prepared in response to my Telex of May 5, 1981: Does the total corrected common backfill material quantity shown in "8" as 7,100,785 bcy include material site losses for common backfill material reused from ditch excavation? (Refer to my memo dated 5/13/81)
- A The quantity as shown was corrected for mathematical errors, but was not corrected to exclude material site loss from common backfill material reused from ditch excavation. We are in the process of recalculating these quantities and will inform you of the results.

JW:ml

WILLIAMS
BROTHERS
ENGINEERING
COMPANY

TELECOMMUNICATION
SERVICES REQUISITION

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☐ 30 RSC ☒ 31 WBEC ☐ 34 H & N ☐ 33 ARSC ☐			

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OVERTIME AUTHORIZED BY

Doyle Pierce

DATE

5/27/81

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WBEC MESSAGE CENTER

3 Pages to Follow

To Confirm Receipt:

(910)-496-5213

A. : Questions regarding Permits and Trend A264

A-1) Response Pages 7-10, 7-62 and 7-64 show 79,100 additional man-hours, plus 58,968 hours from CCE for a total of 138,060 hours. Man power development chart on Page 7-65 shows 138,060 hours for Irvine and Houston plus 36,400 hours for Fairbanks. Text on Page 7-62 says increase is for Irvine, Houston and Fairbanks. Where are additional hours for Fairbanks costed?

A-2) Irvine subtotals on Response Page 7-65 are confusing. What are correct subtotals by quarter? Which positions are counted to arrive at subtotals?

A-3) Response Page 7-64 shows 59,968 hours from CCE for permits. Volume XXXII of CCE, Page 65, shows following:

Operation 11, Proj. Engr. - Permits for 87 man-quarters

Operation 28, Clerical - Permits - Irv. for 24 man-quarters

Operation 28, Clerical - Permits - Houston for 37 man-quarters

At 468 hours per quarter, these three positions total 69,264 man-hours. Why the difference between Response Page 7-64 and CCE Volume XXXII Page 65? In the CCE, who provides supervision for the Houston clerical - permits staff?

- A-4) The man power development chart on Response Page 7-65 does not identify a Project Engineer - Permits as shown on Page 65 of CCE Vol. XXXII. Does the man power chart in Trend A264 replace the Project Engineers shown in the CCE? The trend chart does not show a clerical staff for Houston. Have these positions been eliminated?
- A-5) The trend chart on Response Page 7-65 shows a Section Supervisor and six positions for Sections One through Six. Are these the six pipeline sections? If so, what differentiates the duties of the six sections from the pipeline position shown under Facilities Supervisor? From the Minerals and Materials Sites position?
- A-6) Response Page 7-64 shows base salary computed at \$12.34 per hour for all hours, which is same as CCE average for Area 84. Have you computed average for positions shown on Response Page 7-65? If so, does it match figure shown on Page 7-64?

B. Questions regarding Environmental Affairs

- B-1) Response Page 7-113 indicates that the environmental staff of 14 in CCE should be increased to 24 per 1981 scope of work. The 24 equivalent positions on Pages 7-114 through 7-117 do not include all of the 14 positions on Page 64, CCE Volume XXXII. Does the staff shown on Response Pages 7-114 to 7-117 replace the CCE staff?

- B-2) Please provide hourly rate, and duration and/or beginning and ending quarter for each assignment on Response Pages 7-114 to 7-117 (similar to detail on Page 64, Vol. XXXII).
- B-3) Response Page 7-115 shows Coordinator of Unit 20 PMC Biological Programs as full time consultant service position but shows zero under "Number Required." Why is the position shown with zero staffing level?
- B-4) Response Page 7-113 says CCE should be increased by 39,000 man-hours. Page 7-119 shows 39,000 hours for Irvine and 13,100 hours for Fairbanks. Summary on Response Page 7-10 shows 52,100 hours for Trend A-265. Please provide backup for Fairbanks hours in same detail as CCE.

IT-015-FLUOR

1981 JUN -5 PM 1: 58

5315/480 / Carolyn
Rush 445
Carolyn

37783

V FLUOR

FACSIMILE LEAD SHEET

5 JUN 81 16:28

6/4/81
CC: RDM
rfD. W. Brown
ENGINEERS AND CONSTRUCTORS, INC.
Southern California DivisionTELEPHONE: (714) 975-2000
TELEX: 69-2488TELETYPE FACSIMILE
DEX 700: (714) 975-5272
RAPIFAX: (714) 975-5271
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CORPORATE HEADQUARTERS

TELEPHONE: (714) 975-2000
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DFA 700: (714) 975-6989
XEROX 400: (714) 975-6990Number of documents
including lead sheet: 8

Company Name: Williams Brothers Engineering Company

Attention: DOYLE BEARD (41916-5364)

Originator's Name: D. W. Brown/J. W. Griffin Extension: 6654

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A. Questions Re: Permits and Trend A264

A-1) There are no additional manhours requested for Fairbanks in Trend A264 response page 7-64. The text on response page 7-62 is incorrect and should refer to only Irvine and Houston. The Fairbanks Staffing presented on response page 7-63 is consistent with that in the CCE.

A-2) See attached copy of response page 7-65. The correct Irvine subtotals and positions are enclosed in a .

A-3) The hours reflected on response page 7-64 (Potential Trend A264) are incorrect. The definitive trend in process will reflect the following manhours taken directly from page 75, Volume XXXII of the CCE.

Operation 11, Proj. Engr. (Irvine)	- 87 Manquarters
Operation 11, Proj. Engr. (Houston)	- 15 Manquarters
Operation 28, Clerical (Irvine)	- 24 Manquarters
Operation 28, Clerical (Houston)	- 37 Manquarters

At 468 hours per quarter, these total 76,284 manhours. Your total of 69,264 manhours did not reflect the two Project Engineers for Houston at 15 manquarters.

In answer to who provides supervision for the Houston Permits Clerical in the CCE. It is provided by the Permits Project Engineers.

A-4) The Manpower Development Chart (Trend Chart) on response page 7-65 does replace the manpower displayed in the CCE, and except for the Clerical Operation 28 on the Trend Chart, the staff is still composed of Project Engineers, Operation 11.

The clerical staff for Permits in Houston has been eliminated. Clerical support is provided from a pool which is budgeted under an element other than Project Directorate, i.e. Pipeline.

A-5) The Section Supervisor and six positions for sections shown on response page 7-65 are for the six Pipeline Sections.

The attached Permits PMC Functional Organization Chart shows the differentiation between the duties of the six sections and the Pipeline position under Facilities Supervisor.

The duties of the Minerals & Material Sites Pipeline position include the assembly and preparation of documents required to obtain all of the sand, gravel and similar materials for work pads, pipe bedding and backfill and concrete aggregate for the entire pipeline. This activity has developed into a major task requiring a full time person.

- A-6) The base salary rate shown on response page 7-64 is the CCE Average for Project Directorate. This rate is used on Rough Order of Magnitude Potential Trends i.e. A264. The Definitive Trend in process will reflect the CCE rates for the Permits Staff and will not match the figure on response page 7-64. This rate is \$14.31/Hour and will adjust the total accordingly.

B. Questions Regarding Environmental Affairs

- B-1 The staff shown on response pages 7-114 to 7-117 does replace the positions on page 64, CCE Volume XXXII.
- B-2) See Attachment #3.
- B-3) The position for Coordinator of Unit 20 PMC Biological Programs on response page 7-115 reflects a zero staffing level because the position will not be filled by a PMC person. The exhibit addresses PMC Staff only. The coordinator position will be filled by one outside consultant.
- B-4) See Attachment #4.

ATTACHMENT 1

LOVELL

MANAGER

SECRETARIAL - CLERICAL

CONTRACT TEAM

SECTION SUPERVISOR

SECTION 1

2

3

4

5

6

FACILITIES SUPERVISOR

MINERAL & MTL. SITES

TEMPORARY FACILITIES

PIPELINE

COMPRESSOR STATIONS

SUM TOTAL

FAIRBANKS

SECTION SUPERVISOR

SECTIONS NORTH

SECTIONS SOUTH

SUM TOTAL

HOUSTON (FOS)

PERMITS SUPERVISOR

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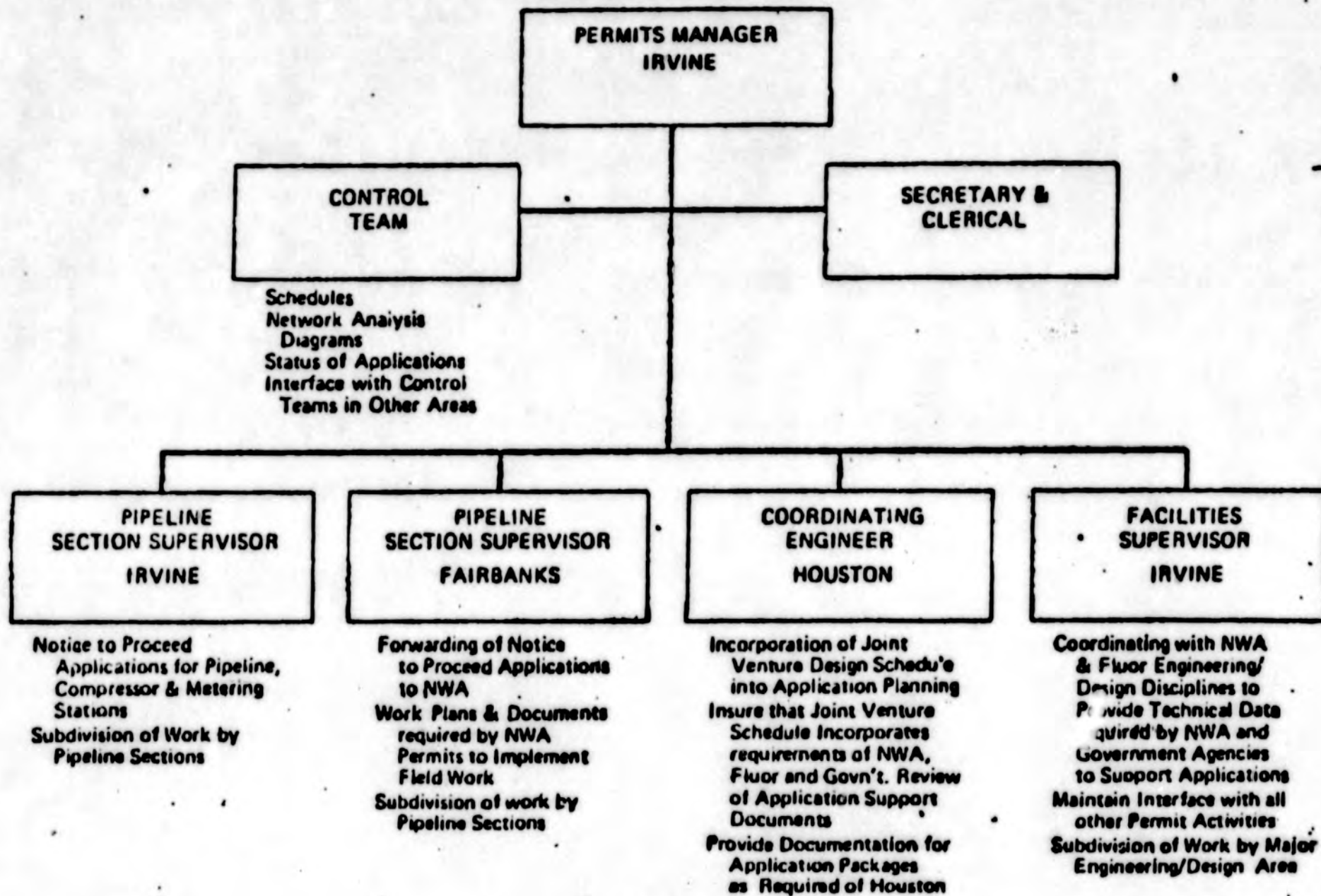
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IN PROJECT
CONTROL
BUDGET

Resource

Page 7-63

**PERMITS
&
DOCUMENTATION GROUP
PMC ORGANIZATION**



9.1-2

Figure 9.1-1

ATTACHMENT 3Summary of ManquartarsArea 50Irvine/Houston

	Labor Grade	Pay Grade	<u>1980</u>				<u>1981</u>				<u>1982</u>			
			1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th
Envir. Mgr.	E10	20.97	1	1	1	1	1	1	1	1	1	1	1	1
Coord. Staff Oper.	E9	19.04					1	1	1	1	1	1	1	1
Superv. Permits	E5	13.01	1	1	1	1	1	1	1	1	1	1	1	1
Sect. Team Biologists	E5	13.01					4	6	6	6	6	6	6	6
Superv. Info. Mgmt.	E8	17.31	1	1	1	1	1	1	1	1	1	1	1	1
Info. Mgmt. Librarian	NE6	7.93			1	1	1	1	1	1	1	1	1	1
Info. Mgmt. Data Controller	E5	13.01					1	1	1	1	1	1	1	1
Staff Biologist	E5	13.01	1	1	1	1	1	1	1	1	1	1	1	1
Coord.. Envir. Eng.	E7	15.75	1	1	1	1	1	1	1	1	1	1	1	1
Envir. Eng.	E5	13.01	1	1	1	1	3	3	3	3	3	3	3	3
FERC Filing Coord.	E9	19.04	1	1										
<u>Houston</u>														
Coord. Civil Eng.	E8	17.31			1	1	1	1	1	1	1	1	1	1
Visual Resource Specialist	E5	13.01			1	1	1	1	1	1	1	1	1	1
Staff Specialists	E3	10.76			1	1	3	3	3	3	3	3	3	2
Envir. Eng.	E5	13.01					1	1	1	1	1	1	1	1
			7	7	10	10	21	23	23	23	23	23	23	22
Steno & Clerical	NE4	6.17	1	1	1	1	1	1	1	1	1	1	1	1
GRAND TOTAL			8	8	11	11	22	24	24	24	24	24	24	23

ATTACHMENT 4 a

Summary of Manpower

Area 50

Fairbanks	Labor Grade	Pay Grade	1980				1981				1982			
			1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th
Environmental Mgr.	E9	23.06						1	1	1	1	1	1	1
Administrative Asst.	N6	10.90									1	1	1	1
Subtotal								1	1	1	2	2	2	2
no & Clerical	N3	7.37					1	1	1	1	2	2	2	2
Environ. Engr. Super.	E7	17.33	1	1	1	1	1	1	1	1	1	1	1	1
Assess & Permit Coord.	E5	15.76								1	1	1	1	1
Air Quality Specialist	E5	15.76										1	1	1
Waste Mgmt Specialist	E6	17.32						1	1	1	1	1	1	1
Hyd & Sanitary Engr.	E5	15.76									1	2	2	2
Restor. Eng. Superv.	E7	19.07										1	1	1
Restor. Eng.	E5	15.76					1	1	1	1	1	1	1	1
Agronomist	E5	15.76											1	1
Design Technician	N5	9.50												1
Oil Spill Specialist	E6	17.33									1	1	1	1
Environ. Orient Coord.	E5	15.76					1	1	1	1	1	1	1	1
Biologist Supervisor	E7	19.07							1	1	1	1	1	1
Biologist	E5	15.76	2	2	2	2	3	4	4	4	4	4	4	4
Data Mgmt. Superv.	E7	19.07										1	1	1
Biologist	E5	15.76										1	1	1
Archaeologist	E5	15.76										1	1	1
Technician	N5	9.58										1	1	1
Data Controller	E5	15.76										1	2	2
Subtotal			3	3	3	3	7	9	10	11	19	22	23	
Grand Total			3	3	3	3	7	10	11	12	15	23	26	27

Area 50

Fairbanks

	Labor Grade	Pay Grade	1983				1984				1985				Total Man Qtrs.
			1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	
Environmental Mgr.	E9	23.06	1	1	1	1	1	1	1	1	1	1	1	1	17
Administrative Asst.	N6	10.90	1	1	1	1	1	1	1	1	1	1	1		15
Subtotal			2	2	2	2	2	2	2	2	2	2	2	1	32
Steno & Clerical	N3	7.37	2	2	2	2	2	2	2	2	2	2	2	2	34
Environ. Engr. Super.	E7	17.33	1	1	1	1	1	1	1	1	1	1	1		23
Assess & Permit Coord.	E5	15.76	2	2	2	2	2	2	2	2	1	1			
Air Quality Specialist	E5	15.76	1	1	1	1	1	1	1	1	1	1			13
Waste Mgmt Specialist	E6	17.33	1	1	1	1	1	1	1	1	1	1	1	1	18
Hyd & Sanitary Engr.	E5	15.76	3	3	3	3	3	3	3	3	3	3	3		40
Restor. Eng. Superv.	E7	19.07	1	1	1	1	1	1	1	1	1	1	1	1	15
Restor. Eng.	E5	15.76	1	2	2	2	3	3	4	4	4	4	4	4	39
Agronomist	E5	15.76	1	1	1	1	1	1	1	1	1	1	1	1	14
Design Technician	N5	9.50	1	1	1	1	2	2	2	2	2	2	2	2	21
Oil Spill Specialist	E6	17.33	1	1	1	1	1	1	1	1	1	1	1		17
Environ. Orient Coord.	E5	15.76	1	1	1	1	1	1	1	1	1	1			18
Biologist Supervisor	E7	19.07	1	1	1	1	1	1	1	1	1	1			16
Biologist	E5	15.76	4	4	4	4	4	4	4	4	3	2			65
Data Mgmt. Superv.	E7	19.07	1	1	1	1	1	1	1	1	1	1	1	1	15
Biologist	E5	15.76	1	1	1	1	1	1	1	1	1	1	1		14
Archaeologist	E5	15.76	1	1	1	1	1	1	1	1	1	1	1		14
Technician	N5	9.58	1	1	1	1	1	1	1	1	1	1	1		14
Data Controller	E5	15.76	2	2	2	2	2	2	2	2	2	2	2		27
Subtotal			25	26	25	26	28	28	29	29	27	26	20	10	406
Grand Total			29	30	30	30	32	32	33	32	31	30	24	13	490

**PLEASE NOTE: THE PRECEDING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.**

**PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT**

SEP 26 1980

Alaskan Northwest Natural Gas
Transportation Company

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Docket No. CP80-435

INTERIM REPORT TO THE COMMISSION
BY THE ALASKAN DELEGATE
AND THE DIRECTOR, AUDIT AND COST ANALYSIS,
OFFICE OF THE FEDERAL INSPECTOR

In its order of August 1, 1980 in the above captioned proceeding, the Commission directed the Alaskan Delegate, assisted by the OFI Division Director, to commence a series of technical conferences on the project sponsors' cost estimate for the Alaska segment of the ANGTS and related incentive rate of return (IROR) issues. The order inter alia offered the parties an opportunity to file comments on procedures for the conferences, and directed the Delegate to consider those comments with the parties at the first conference.

The first round of conferences was held on September 3 and 4, 1980, and dealt mainly with procedural issues. Prior to the conferences, procedural comments were received from the project sponsors and the Commission's trial staff. The comments, and the discussion that ensued, focussed primarily on the scheduling and location of the conferences, transcription of the conferences, and procedures for exchanging information. These matters were discussed at length in the morning session of September 3 and the afternoon session of September 4; the results of those discussions are summarized below.

Cost Estimate Formats

The afternoon session of September 3 was scheduled to consider cost estimate formats. That session was very brief in that no party indicated any disagreement with the cost estimate formats previously submitted by the project sponsors. We expect the sponsors' formats to be agreed to by the parties at next week's conference.

IROR Methodology Issues

The conferences opened with (and later returned to) a discussion of the concern expressed by the Commission in its August 1, 1980 order (at page 10), namely that:

The Commission's orders establishing the IROR mechanism contemplated that all such [design] issues would have been resolved prior to the filing of the CCSE.

The design issues identified in the conferences as having some potential for resolution on a basis other than that contemplated by Alaskan Northwest's July 1 filing were:

1. Separation distance between the ANGTS and the Trans-Alaska (oil) Pipeline System (TAPS);
2. The possibility of utilizing a tunnel of approximately two and one-half miles in length to bypass the most difficult portion of the Atigun Pass in the Brooks Mountain Range in northern Alaska;
3. Burial of the pipeline in a silt or embankment mode, rather than in a trench; and
4. Access roads and work pads constructed of snow, with increased emphasis on winter construction, as opposed to access roads and work pads made of gravel, with emphasis on summer and "shoulder" months for the construction period.

The first of these issues, the separation or alignment question, was left open to some degree by Congress and the President in selecting the approved transportation system. 1/ On this basis, the Commission in its orders in Docket No. RM78-12 expressed its intention to consider establishing the Certification Cost Estimate (CCE, or occasionally referred to as the Certification Cost and Schedule Estimate, or CCSE) upon appropriate resolution of this issue. 2/ The issue has now been resolved by the Department of the Interior (DOI), on a basis slightly different from that on which the July 1 filing was based. DOI's proposed right-of-way grant allows for the possibility, upon completion of considerable further study, of authorizing the alignment originally proposed by Alaskan Northwest, 3/ but Alaskan Northwest suggested in our conferences that they would likely accept DOI's

1/ The nature and route of the approved system was specified in Section 2 of the Decision and Report to Congress on the Alaskan Natural Gas Transportation System (Executive Office of President, Energy Policy and Planning, September 1977). Approved by Joint Resolution of Congress, the Decision has the legal force and effect of a Federal statute. The Decision states (at page 7):

From Prudhoe Bay to Delta Junction, Alcan expects to construct its line approximately eighty feet from the Alyeska oil pipeline. As proposed by Alcan, construction will be carried out by extending the existing Alyeska work pads. However, Alyeska advised that the Alyeska and Alcan lines must be separated by 100 to 200 feet where blasting to build the pipeline trench would occur (approximately 350 miles of pipeline length). Additional studies will determine the minimum distance between the Alyeska oil pipeline and the Alcan line that is necessary to permit safe construction and operation.

2/ See, e.g., Order No. 17-A, "Order Confirming the Incentive Rate of Return Mechanism and Denying Petition for Reconsideration and Classification," Docket No. RM78-12 (issued January 17, 1979).

3/ The proposed grant with its terms is contained in a letter, dated August 20, 1980, from Guy R. Martin, Assistant Secretary for Land and Water Resources, Department of the Interior, to Mr. John McMillian, Chairman of the Board of Directors for Alaskan Northwest Natural Gas Transportation Company, the sponsor of the Alaska segment. As mentioned later in this interim report, we have asked that this letter with its attachments be filed and served on the parties to this proceeding.

preferred routing. Accordingly, we believe it is appropriate to try to develop a recommended CCE value based on the revised alignment.

With respect to the other issues identified in our initial conferences, Alaskan Northwest characterized the burial mode and access road/work pad issues as ones for which the July 1 filing contained their preferred resolution, but for which agencies of the Federal Government, principally the Federal Inspector and various of his advisory bodies, had requested that alternatives be explored. Alaskan Northwest reported that the alternatives are being explored in good faith, but that Alaskan Northwest believes in the superiority of the preferred alternatives contained in the July 1 filing, and expects those alternatives to be selected when consideration is complete. On the other hand, the tunnel alternative for passage over the Brooks Range is being evaluated as a potentially preferable alternative to the use of Atigun Pass.

The Commission's Alaskan Delegate 4/ and the Commission itself 5/ have stated that the ANGTS approved by the President and the Congress is the system described in the Alcan filing submitted to the Federal Power Commission in March of 1977. 6/ It would seem, then, that the Commission's Order Nos. 31 and 31-B would have been written in the contemplation that it was basically that system (save for the separation issue as discussed above) which was to be constructed and for which the IROR mechanism as adopted by the Commission was to apply.

4/ See, e.g., "Report of the Alaskan Delegate on the System Design Inquiry" (especially at page 51), attached to "Notice of Delegate Report and Order Inviting Comments," issued by the Commission in Docket No. CP78-123, et al., on May 17, 1979.

5/ See, e.g., "Notice of Proposed Rulemaking and Statement of Policy," Docket No. RM79-19 (issued February 2, 1979) at page 7, and Order No. 45 (issued in that proceeding on August 24, 1979) at page 5 (rehearing pending).

6/ "Alcan Pipeline Project 48-inch Alternative Proposal," Docket No. RM77-6, filed on March 8, 1977.

Section 9 of the Alaska Natural Gas Transportation Act (ANGTA) limits changes to the approved system to those which would not

... compel a change in the basic nature and general route of the approved transportation system or otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system.

The question which arises for exploration in our proceeding is whether all changes such as would meet this test, including presumably any of the additional three mentioned above if ordered by the Government, 7/ are within the contemplation of Order Nos. 31 and 31-B.

Alaskan Northwest's proposal is to treat all such changes as "design changes" as allowed for by the Commission in Orders Nos. 31 and 31-B. As postulated in the Commission's August 1, 1980 order (at page 10), we think an alternative value of the CCE is appropriate for the new resolution of the separation issue, because of the referenced language regarding the separation issue in Order Nos. 17 and 17-A. In this proceeding, we will attempt to determine whether additional alternative values of the CCE are appropriate for alternative resolutions of other outstanding design issues, and, as requested, will address development of guidelines to govern the design change process envisioned by the Commission's orders.

With respect to procedure, it seems apparant that Alaskan Northwest's July filing is based on the same design concepts as the March 1977 filing, although those design concepts have been greatly refined since that time through expenditure of considerable time

7/ Condition No. I.5. at page 29 of the Decision requires that the project sponsors develop a final design, design cost estimate, and construction schedule for submission to and approval by the Federal Inspector prior to the initiation of construction. At that stage, the Inspector could order changes as a condition of his approval.

The Commission provided a discussion of its understanding of the design change problem as part of its change in scope discussion at pages 120-138 of Order No. 31 (issued June 8, 1979).

and effort. Alaskan Northwest suggests, and we concur, that the July 1 filing is an appropriate base from which to begin development of CCE and Center Point (CP) values for the Alaska segment. The cost consequences of any alternative resolutions of outstanding design issues would be developed by Alaskan Northwest as variations off of the basic cost information presented in that filing, and could best be evaluated by the Commission and the parties as variations from that base. Detailed evaluation of the basic estimate could thus be a step in evaluating estimated costs of any alternatives, even if our report to you ends up recommending CCE values for alternative designs.

Another aspect of the Commission's concern in this area was also addressed during our conferences. We raised the question of whether the recent agreement between the project sponsors and the North Slope producers on a cooperative study for design and engineering of the pipeline and conditioning plant would not result in some further changes to the design of the pipeline beyond those currently being studied. We were assured that that agreement did not contemplate such further changes. We requested that the agreement be filed and served on all parties to this proceeding, and that a statement on behalf of the parties to that agreement be filed and served on all parties to provide some idea of the agenda and timetable for the design review being conducted pursuant to that agreement.

As regards further proceedings on the IROR methodology issue, we agreed on the following additional steps:

1. In addition to filing and serving the cooperative study agreement, we asked that the sponsors file and serve the communication from DOI regarding the right-of-way grant.
2. We have developed a working paper on IROR concepts which is being circulated as an attachment to this report.

3. The Federal Inspector's report requested by the Commission to identify the major outstanding design issues from his perspective is expected to be submitted by the end of September. At approximately the same time, the project sponsors will submit the above-mentioned statement from the producer-sponsor study group, plus any further thoughts they may have with respect to (a) other outstanding major design issues, and (b) a more complete statement of their views regarding how such changes should be handled for purposes of the IROR mechanism.

4. At the same time, any other party may also submit its own comments on design issues, including any design changes that such party wishes to propose for consideration. (In this regard, Exxon, ARCO and Sohio took the position that the design should include the conditioning and processing facilities required to prepare the gas for pipeline entry.) Reports and comments on design issues, as submitted by the project sponsors and the parties, should also address the IROR implications of those issues.

5. The project sponsors expect to file by October 15 appropriate revisions to their proposed CCE to account for the changed separation from the oil pipeline. They indicated that they expect to have information available on the cost consequences of other design alternatives by the end of October.

Several parties (including, in particular, the trial staff) expressed reluctance to consider the IROR issues until after the parameters of the outstanding design issues had been clarified in the conferences. On the other hand, we felt that it was important to begin exploration of IROR questions early in the conferences, as application of the IROR mechanism is an important element of the context in which the Commission and the

parties consider the sponsors' cost estimate filings. The compromise that we struck was to begin exploration of the IROR topics in a special conference in the week of October 6, 1980, then return to it at the end of the conferences.

Schedule of Future Conferences

Williams Brothers Engineering Company, the consultants recently retained by OFI, indicated a need to spend several days at the offices of the sponsors' project management contractor in California meeting with the project sponsors to familiarize themselves with the organization and methodology of the sponsors' filing. Those informational sessions were held on September 16-18. All parties were invited to participate. No decisions were reached at these sessions, and no transcript was prepared. The Alaskan Delegate and the OFI Division Director did not attend these sessions.

Further technical conferences will commence in the last week of September. We originally announced our intention to hold the conferences on alternate weeks pursuant to the following schedule:

September 30

October 14

October 28

November 11

November 25

However, inasmuch as several of these weeks involve Federal holidays our present intention is to reevaluate the schedule through discussion with the parties at the September 30 conference.

Each conference will commence on a Tuesday, and will continue for as many days as the parties consider useful and appropriate, but will terminate no later than the Friday of

the week in which it commenced. The Alaskan Delegate or the OFI Division Director will preside at each of these conferences, and a limited transcript will be kept (as discussed below).

The first conference will be held in California. The location of the ensuing conferences will be determined at a later date, taking into consideration the subject matter to be discussed.

The following subjects will be taken up at the conferences, in this order:

1. Estimate format
2. Pipeline
3. Compressor and metering facilities
4. O & M facilities
5. Temporary facilities and services
6. Communications and supervisory systems
7. Project directorate
8. Potential design changes and P/L adjustments
9. Center Point and contingency and finance charges

The first conference will start off dealing with all subject areas to determine, to the extent possible, general areas on which there is substantial agreement or disagreement. The conference will then concentrate on subjects no. 1 and no. 2 above. At the conclusion of each conference, the parties will determine the scope and agenda of the next scheduled conference.

The conferences will continue until we and/or the parties conclude that they are no longer productive. We have tentatively scheduled them through the end of November, anticipating that they can usefully continue at least that long. At about that time, we will advise the Commission regarding our expected schedule for any further proceedings.

In addition, as mentioned above, a conference will be held in Washington on October 7, to consider design issues and their IROR implications.

The Delegate will issue a notice of each conference, identifying the date, place and subject matter of the conference. A copy of the notice announcing the September 30 and October 7 conferences is also attached to this report.

Transcripts

The project sponsors and the trial staff recommended that no transcripts be kept of the conferences, contending that the discussions would be faster, freer and more productive without them. Alaska, Exxon, and ARCO, on the other hand, recommended that verbatim transcripts be kept, contending that they would be needed to accurately record the results of the conferences as well as to keep all parties fully informed. After lengthy discussion, the Delegate established a compromise procedure designed to balance and accommodate all of these legitimate concerns to the extent feasible.

A court reporter will be present at all of the technical conferences (i.e. except for the pre-conference informational sessions during the week of September 16). All agreements by the parties present at the conference will be transcribed. When the parties disagree, but have discussed a subject at sufficient length to crystallize the nature of their disagreement with some degree of precision, their respective positions will be transcribed. In addition, the transcript will include a summary of the topics discussed, and a description of the agenda for the next conference. The transcript will also include a description of all informal exchanges of information between a party and a decisional person (generally, Williams Brothers personnel) that have occurred prior to the conference and subsequent to the last such transcription (see discussion below). Parties present at the conference may also include in the transcript any other procedural or substantive matter that is reasonably pertinent to the proceeding. Within these general parameters, the conferences

will make very liberal use of "off the record" discussions, including simultaneous meetings in smaller groups, and free flowing consideration of thoughts, ideas and questions as they occur.

After careful consideration of the views expressed by the parties, it is our conclusion that this procedure will satisfy the legitimate needs of the parties (and of the OFI and the Commission) for an accurate record of the progress of the conferences and the conclusions reached (including conclusions in the nature of sharpened, articulated disagreements), without inhibiting the free flow of discussion. Parties who wish to be informed of the processes by which these positions and conclusions are reached will in any event have full opportunity to participate directly in the conferences themselves. In reaching this conclusion, we also note that the conferences are not formal evidentiary hearings, and that there will be no testimony under oath or cross-examination of witnesses. The purpose of the conferences is to assist the Alaskan Delegate and the OFI Division Director in the preparation of their report to the Commission by organizing the information and clarifying the issues; all parties will have ample opportunity to file comments and reply comments on the report itself.

In this regard, several parties inquired as to whether the conferences would be deemed part of the Commission's "record" of the proceeding. It is our conclusion (and we so stated) that the record of the conferences would be part of that "record" in the sense that they constitute preliminary, informal consideration of the subject matter designed to culminate in the issuance of a formal notice inviting comments and reply comments.

Finally, in the course of discussion of the transcript procedure, one party referred us to the following sentences on page 9 of the Commission's August 1, 1980 order:

Stipulations and other agreements are encouraged, and will be included in the final report to the Commission. Unanimous agreement among the participants at a conference shall be deemed to constitute unanimous agreement among the parties. Objections to stipulations must be supported by substantial rationale.

It is our understanding (and we so stated) that the Commission's intent was to maintain steady progress at the conferences by precluding parties at a later conference from re-opening agreements and stipulations reached at earlier conferences. As we understand it, however, the above quoted passage was not intended to preclude the Alaskan Delegate and the OFI Division Director from exercising their independent judgment in the preparation of their report in the event that they reach a conclusion different from one stipulated or agreed upon by the parties. (In such event, the report would set forth the agreement or stipulation, and state why the Delegate and Division Director disagree with it.) Similarly, it is our understanding that the Commission did not intend to preclude any party (whether or not it participates in the technical conferences) from raising any issue in its comments and reply comments on the Delegate and Division Director's report to the Commission, regardless of any stipulations and agreements upon which the report may have been premised.

Exchanges of Information

The Delegate first noted the August 15, 1980 comments from the Commission's trial staff, dealing, in large part, with the area of discovery. The Delegate pointed out that the technical conferences were intended to deal with the CCE, CP and related IROR matters only. To the extent that trial staff or other parties seek information that is to be dealt with in the final FERC certification proceeding (e.g., information relating to the financing plan or the marketability of Alaskan gas) or that relates to matters which are the responsibility of the OFI (e.g., the project sponsors' management plan), they must rely

on methods of access available to them through means other than the technical conferences. The parties should deal directly with each other in obtaining access to documents and other information. The Delegate or the Division Director will rule on the production of documents directly relevant to this proceeding when the parties cannot reach agreement among themselves.

Williams Brothers, OFI's consultant assisting the Alaskan Delegate and the OFI Division Director in the preparation of their report, indicated a continuing need to obtain information informally from the project sponsors on their cost estimate. Similarly, the trial staff and their consultants indicated an occasional need to consult with Williams Brothers on questions of common interest. Both the project sponsors and the trial staff indicated that their respective rights would not be prejudiced by such private oral communications between conferences provided that the communications were fully disclosed at the next conference. No other party objected to this procedure, and all parties who expressed an opinion agreed that this procedure would expedite the conferences by enabling all participants (including Williams Brothers) to be better prepared for them.

Accordingly, any party may communicate privately with William Brothers personnel between conferences (or prior to the first conference). At the next conference subsequent to such communication, the contents of the communication will be disclosed and will be recorded in the transcript. Williams Brothers will maintain a log of all such communications, which will be reproduced as part of the transcript (or, if it is voluminous, will be circulated separately by the Delegate to all parties on the restricted service list).

The trial staff also indicated a possible need to obtain oral information from OFI on occasion. In such event, the OFI Division Director will record and report on the communication. Similarly, in the event of a need for communication between any party and

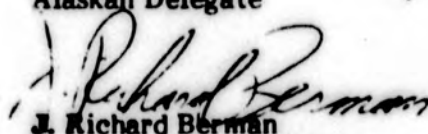
James McCullough, the Alaskan Delegate's IROR consultant, Mr. McCullough will record the communication and disclose it at the next conference.

In the event that information is communicated in written form between a party and either the Delegate, OFI or Williams Brothers, the sender of the written communication will serve copies of it on all parties on the restricted service list. If the information is voluminous and appears to be of limited interest, the party communicating it may circulate instead a short description of the material and an offer to provide copies to any parties indicating a desire for such.

The Alaskan Delegate will establish a public file in his office containing all of the transcripts and other materials generated by the conferences. The trial staff will ensure that the Commission's central filing system contains the same material, under Docket No. CP80-435.



John B. Adger, Jr.
Alaskan Delegate



J. Richard Berman
Director, Audit and Cost
Analysis, Office of the
Federal Inspector

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Alaska Northwest Natural Gas
Transportation Company

Docket No. CP80-435

Notice of Technical Conferences

(September 23, 1980)

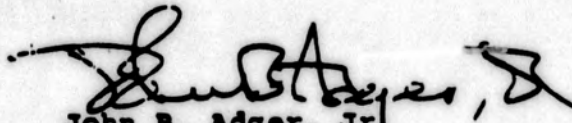
Notice is hereby given of the resumption of the series of technical conferences convened to consider for rate of return purposes the materials filed by the sponsors of the Alaska segment of the Alaska Natural Gas Transportation System in this docket on July 1, 1980. These conferences are being held pursuant to the Commission's order issued in this proceeding on August 1, 1980.

Two additional conferences are being scheduled at this time. The first will attempt an inventory of contested issues in all topic areas addressed by the July 1 filing, then focus on a discussion of any issues with regard to (1) the sponsors' cost estimate format, and (2) the pipeline construction component of the total cost estimate. The conference will also reconsider certain aspects of the conference schedule discussed previously. This conference will take place at the Fluor Corporation headquarters at 3333 Michaelson Drive, Irvine, California, and will begin at 1:00 p.m. on Tuesday, September 30, 1980, and continue until adjourned; in any event no later than Friday, October 3, 1980. The precise location of the conference will be posted at Fluor's headquarters on the day of the conference, and can be obtained in advance by calling Frieda Whiteside at (714) 975-6032.

The next succeeding conference will be held at the Commission's offices in Washington, D.C., beginning at 10:00 a.m. on Tuesday, October 7, 1980. This conference will consider a report from the Office of the Federal Inspector on major outstanding design issues, certain additional submissions regarding potential design changes from the project sponsors, and any further submissions from any other parties, in beginning to address the issue of the treatment of major design changes under the incentive rate of return (IROR) mechanism prescribed for the ANGTS by the Commission, and to address the development of guidelines to govern the design change process called for by that same IROR mechanism. That conference will also continue until adjourned, in any event no later than Friday, October 10. The precise location of this conference at the Commission's offices

will be posted on the day of the conference, on the second floor bulletin board at 825 North Capitol Street, Washington, D.C. Further information about this conference can be obtained from Miss Jeanne Barrie at (202) 357-8900.

In accordance with the agreement reached at the conference of September 3-4, 1980, summary transcripts will be prepared for both the Washington and Irvine conferences. Information about obtaining copies of those summary transcripts is available from Miss Jeanne Barrie at (202) 357-8900.


John B. Adger, Jr.
Alaskan Delegate

WORK PAPER WP-1
THE FERC REGULATORY FRAMEWORK OF THE CENTER POINT
OF THE IROR MECHANISM

James D. McCullough
September 22, 1980

Prepared for
"Comparative Cost Analysis for the Alaskan Segment, ANGTS Task"
Federal Energy Regulatory Commission
Contract DE-AC39-80RC-10477

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The FERC Regulatory Framework of the Center Point of the IROR Mechanism

I. Introduction

The purpose of this brief paper is to compile FERC's published regulatory comments on the Center Point established for the Incentive Rate of Return Mechanism (IROR) - its definition and scope. Of particular interest are the types of events contributing to cost uncertainty which are to be included in - and excluded from - the Center Point. A separate paper will explore the technical statistical aspects of the Center Point (CP).

II. Center Point Definitions

(a) "Center Point -- The value of the Cost Performance Ratio which would be achieved at the expected or most likely level of construction costs for the pipeline. The difference between the Center Point and 1.0 is a measure of the likely or expected level of cost overruns from the Projected Capital Costs of the project."¹

(b) "Cost Performance Ratio -- The ratio of deflated Actual Capital Costs to Projected Capital Costs. This ratio is used to measure the performance of the project sponsors in achieving the budgeted cost of construction and reducing cost overruns."¹

The ratio is adjusted for inflation and for design and other scope changes.

¹Federal Energy Regulatory Commission, Order No. 17, "Order Attaching Incentive Rate of Return Conditions to Certificates of Public Convenience and Necessity," Docket No. FM 78-12, December 1, 1978, pg. 20.

(c) "Deflated Actual Capital Costs ... the sum of direct construction costs actually incurred in the construction of the pipeline after conversion into base-year prices ... plus a Finance Charge calculated from the Real Rate of Return ..."¹ The Finance Charge is based on the Real Rate of Return (set at 5 percent).

(d) "Projected Capital Costs ... the sum of direct construction costs included in the Certification Cost and Schedule Estimate approved by the Commission pursuant to Condition 7, ... and after any adjustments for Changes in Scope ... or resulting from design changes prior to the Final Design ... plus a Finance Charge calculated from the Real Rate of Return."¹

Design Changes and Scope Changes will be discussed below.

III. Center Point Relationship by Formula to IROR Schedule

a. Definitions

1. "Incentive Rate of Return (IROR) -- The rate of return on equity that shall be decreased as the Cost Performance Ratio is increased in order to provide an incentive for project sponsors to keep construction costs as low as possible. This rate of return is referred to as a variable rate of return in the President's Decision."²
2. "Incentive Rate of Return Schedule -- A table or formula establishing a value of the Incentive Rate of Return for each value of the Cost Performance Ratio."²

b. Center Point Relationship to Center Point

"One of the Cost Performance Ratios must be chosen as the starting point for constructing the IROR schedule. Once that point has been assigned a rate of return, and the marginal rate has been chosen, the entire schedule can be determined.

¹FERC, Order No. 31, "Order Setting Values for Incentive Rate of Return, Establishing Inflation Adjustment and Change in Scope Procedures, and Determining Applicable Tariff Provisions," Docket No. RM 78-12, June 8, 1979, pages 241-242.

²Order 17, op. cit., pages 20-21.

The Center Point is that Cost Performance Ratio which is associated with the Center Rate of Return. Ratios above the Center Point will yield rates of return below the Center Rate. Ratios below the Center Point will be rewarded as underruns, with rates of return greater than the Center Rate.

In order for the Center Rate to be perceived by investors as adequate compensation for risk, it should be the rate of return that they can realistically expect their investment to yield. As a result, the Center Point should be set at the most likely Cost Performance Ratio. Then, if the final costs are at the expected levels, the Center Rate will be earned."^{1,2}

c. Formulas to Relate Center Point to IROR and to Determine Center Point

The IROR formulas established for Northern Border and Northwest Alaskan (NWA) are:

"The Incentive Rate of Return shall be set equal to $[(17.5)(CP) + 8(A - CP)]/A$ for the Alaska segment and $[(15)(CP) + 8(A - CP)]/A$ for the Northern Border segment, where A is the Cost Performance Ratio and CP is the Center Point."³

Formulas for the establishment of the Center Point were set forth in Order 31 as follows:

"Based upon the findings of the President's Decision, the Center Point (CP) for the Alaska segment shall be calculated from the following formula:

¹FERC, "Revised Notice of Proposed Rulemaking," Docket No. RM 78-12, September 15, 1978, page 14.

²The IROR will be earned on equity capital in accordance with Condition 16, "Cost of Service Calculations," of Order 31, page 250. A one-time adjustment to the rate base will be made, per Condition 17 (page 251) to permit an "Operation Phase Rate" of 14 percent to be earned on that adjusted amount, per Condition 13 (page 249). The rate base for debt capital funds will include the actual cost of borrowing funds used during construction (AFUDC). The Commission assumed a 25 percent equity capitalization and a 75 percent debt capitalization in determining the Real Rate of 5 percent (see Order 31, page 38).

³Order 31, op. cit., page 249.

Center Point = $[1.3 \times (\text{March 1977 Cost Estimate} + \text{Finance Charge})] / [\text{Certification Cost Estimate} + \text{Finance Charge}]$

where the March 1977 Cost Estimate is in base-year prices.

The Center Point for the Northern Border segment will be calculated from the following formula:

Center Point = $[1.1 \times \text{March 1977 Cost Estimate} + \text{Finance Charge}] / [\text{Certification Cost Estimate} + \text{Finance Charge}]$

where the March 1977 Cost Estimate is in base-year prices."¹

The Commission gave the sponsors the option to elect to not use the formula provided that:

"If the project sponsors believe that a major change in the basic nature of the project from that assumed in the Decision has occurred, and thus, the above procedure [the formula] for setting the Center Point is no longer applicable, then the sponsors, as part of their respective submissions of certification cost estimate, must at a minimum present evidence to the Commission on the following subjects:

- (1) The nature of the changes in the project from that assumed at the time of the Decision.....
- (2) The value or benefit to the Nation and gas consumers of construction of this project in light of the revised cost estimates.....
- (3) The cost increases or cost overruns above the Certification Estimates that may reasonably be expected to occur....."²

¹Ibid, page 247.

²Ibid, pages 52-53

Northern Border elected to follow the formula, and the Commission determined that their Center Point is 1.0758.¹ The Northern Border IROR schedule is shown on Figure 1.

"The Commission, in Order 31, gave the project sponsors two choices or options as to how the Center Point would be determined. The first option was to utilize a formula based upon a comparison of the Certification Cost and Schedule Estimate and the estimates in the President's Decision. In its Motion for Rehearing, Alaskan Northwest objects to this formula approach. Under the second option, the project sponsors could request a Center Point without reference to the formula as part of the Certification Cost and Schedule Estimate submission if a major change had occurred in the project, including likely overruns, that exceeded the estimates in the Decision.

Alaskan Northwest's motion states that '...it now appears very clear that a reasonable cost estimate for the Alaska Segment of the project will exceed the March 1977 cost estimate by more than 30 percent.' The Commission interprets this statement to mean that a major change in the Alaskan segment of the project has occurred since the President's Decision, and thus that Alaskan Northwest has rejected the option of setting the Center Point using a formula approach. Consequently, the Commission will not require that the formula approach be used for the Alaskan segment."²

IV. Minimum Value of Center Point

Upon petition by NWA, the Commission ruled that:

"...the Center Point will not be set at a value less than one. However, the Commission will carefully review the Certification Estimate to determine if it is based upon normal or probable conditions and assumptions, and is an otherwise reasonable estimate, and will adjust the estimate if necessary before approval is granted."³

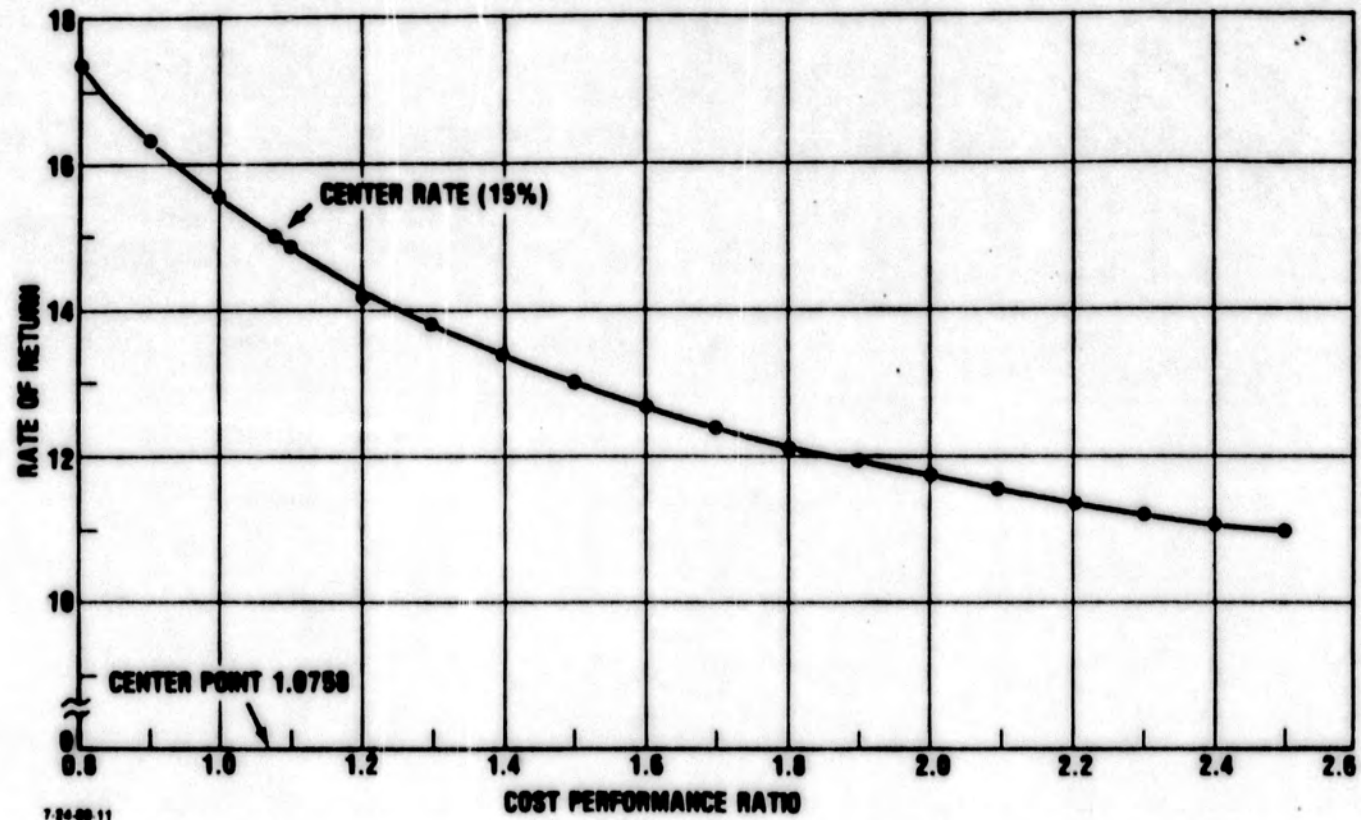
¹FERC - *Findings and Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas*, Docket Nos. CP78-123, et. al., April 28, 1980, page 103.

²FERC, *Order No. 31-B On Rehearing* - Docket No. RM 78-12, September 6, 1979, page 4.

³*Ibid*, page 5.

Figure 1

**NORTHERN BORDER IROR SCHEDULE AS
DETERMINED BY COMMISSION ORDER OF
APRIL 28, 1980**



V. Events to be Included in or Excluded From the Center Point

a. Abnormal Events to be Excluded from the CCE.

"The Commission expects that the Certification Estimates will only include costs resulting from normal conditions to be expected during construction. Abnormal or unlikely events that could increase costs will be analyzed as part of the sponsors' submission concerning potential cost overruns from the Certification Estimate."¹

b. Categories of Abnormal Events

The Commission further clarified the categories of abnormal events in its Order to Northern Border.²

"The Commission has previously dealt with the relationship between normal contingencies and the Center Point of the IROR schedule in its orders defining the IROR mechanism.^{119/} In those orders, the Commission has distinguished among Change in Scope events, abnormal events and the conventional approach to estimation. These references may be categorized into three sets of "events" as concerns the Center Point:

- (1) Abnormal or unlikely events of such importance and consequence that the Commission has designated them as "Change in Scope" events.^{120/} The cost consequences of these events are to be excluded from the cost estimates submitted for use in determining the Center Point. The project sponsors will be permitted to increase the Projected Capital Costs, which serve as the target for assessing cost and schedule control performance, by the estimated costs of Change in Scope Events as approved by the Federal Inspector.

¹¹⁹ See, especially, Order No. 31-B at pages 6-7.

¹²⁰ See Condition 10, Order No. 31-B at page 73.

¹Order 31, op cit., page 54.

²NB Order of April 28, 1980 op. cit., pages 96-97.

- (2) Normal or likely events of a routine nature but of an unknown (but not significant) cost impact, such as are normally included in pipeline construction cost estimates as contingency or management reserve at rates, for example, of 5-7 percent. The cost consequences of these "anticipated unknown" events are to be included as contingencies in estimates submitted for use in determining the Center Point.
- (3) Abnormal or unexpected events that could substantially increase costs but which are not included in the list of Change In Scope events. Examples of such events are 100 year storms, major fires and floods. The cost consequences of these "un-anticipated unknown" events are to be excluded from the normal contingency allowance discussed above, but because these events are not Change In Scope events they are covered only by the Center Point mechanism itself."

VI. Change in Scope Events

The estimated costs of events qualifying as Change-In-Scope Events are to be excluded from the Center Point determination. Order 31-B defined these as:¹

"Such Change in Scope events shall be limited to:

- (1) declared or undeclared war, including civil war or a formally declared blockade,
- (2) any emergency or major disaster which either
(a) is determined, by the President of the United States, pursuant to the Disaster Relief Act of 1974, Pub. L. 93-288, 88 Stat. 143 (as it may be amended) to have occurred in the United States or its territories or possessions, or (b) is determined by the Federal Inspector (i) to have occurred outside the United States or its territories and possessions and (ii) to be of such consequence that, had it occurred in the United States, it is reasonably probable that it would be determined to constitute an emergency or major disaster pursuant to clause (a) above,

¹Order 31-B, op. cit., pages 74-75.

- (4) major changes in pipeline routing or capacity ordered by Federal or State Governments for the Alaska Natural Gas Transportation System from that approved by the Federal Inspector in the Final Design of the pipeline, and
- (5) delay in the issuance of a government permit or certificate necessary for completion of the pipeline system, when such delay (a) occurs subsequent to approval of the Final Design, (b) occurs through no fault of the project sponsors and (c) causes significant cost increases."

VII. Normal Contingencies

NWA expanded upon the Commission's definition of normal contingencies in its Certification Cost Estimate submission:¹

"In-scope estimating uncertainty was carefully defined to separate its impact on project costs from the impact of unexpected events, design changes, and changes in scope. In-scope estimating uncertainty was explicitly defined as the variation in project costs and schedules resulting from:

- Accuracy of material quantity estimates.
- Accuracy of material price estimates.
- Human productivity assumptions.
- Equipment reliability assumptions.
- Engineering/design development.
- Accuracy of scheduled durations.
- Accuracy of bid specifications based on current project definitions."

VIII. Design Changes Prior to Final Design Approval

It should be noted that neither the Certification Estimate nor the Center Point should include an allowance for design changes made prior to approval of the Final Design. Condition 9 of Order 31 permits the Projected Capital Cost baseline to be modified by the addition of the estimated costs of design

¹NWA submitted an estimate for normal contingencies of 12.0 percent of Direct Capital Costs exclusive of Finance Charges, Volume XXXIII, "Normal Contingency, Contingency Methodology and Breakdown, WP-14," July 1, 1980, page 7.

changes incorporated into the Final Design approved by the Federal Inspector.¹ Thus, there is no need to allow for this in the Certification Estimate or Center Point. However, minor Design Changes due to pipeline rerouting subsequent to the Final Design approval, but prior to actual construction, are to be included. See item IX(2) below.

Further, the Projected Capital Costs may not be reduced for design changes that reduce costs.² This is to provide sponsors an incentive to propose design changes that reduce the ultimate costs to consumers. The Commission ruled that changes in design which reduce capital costs at the expense of increased operating and maintenance costs will not be allowed.

The Commission further clarified this ruling in a lengthy footnote to the Northern Border Order:³

"The Commission takes this opportunity to clarify one aspect of Order No. 31-B, regarding revisions to the Projected Capital Costs target for the IROR mechanism. At pages 41 and 42 of Order No. 31-B, the Commission expressed a willingness to accept Northern Border's proposal that Projected Capital Costs should not be reduced for design changes that reduce costs. It has occurred to us that, in theory at least, abuses could arise in the following two types of situations:

- (1) Project sponsors were aware of cost-saving design changes at the time of consideration of the CCSE, but postponed them until after CCSE approval in order to retain a high CCSE and thus improve their expected cost performance ratio, and consequently their IROR; or
- (2) Certain optional assumptions (of which the project sponsors had knowledge at the time of preparation of the CCSE), such as alternate (cheaper) sources or (lesser) specifications for materials or equipment, were omitted in preparing the CCSE for the purpose of increasing its value, only to be changed once the CCSE had been approved.

¹Order 31, op. cit., pages 244-245.

²Order 31-B, op. cit., pages 41-42.

³Northern Border Order of April 28, 1980, op. cit., pages 100-101.

The Commission still believes that Northern Border's basic suggestion is valid. To eliminate any potential for abuse, the Commission states that neither of the two above described situations were intended to result in design changes without adjustment in Projected Capital Costs. Orders No. 31 and No. 31-B were premised on the following assumptions:

- (1) Project sponsors did not know about cost-saving design changes at the time of preparation of the CCSE if such design changes are to be approved without lowering Projected Capital Costs; and
- (2) If optional assumptions were made in preparation of the CCSE, cost-saving design changes will continue to utilize those same assumptions unless the assumption made was the correct one at the time of preparation of the CCSE but had since become inappropriate.

The Commission's intention in accepting Northern Border's suggestion was exactly the reason that led Northern Border to propose it, namely, to give the project sponsors an incentive to propose design changes that reduce costs. The Commission recognized that implementing such an intention will be difficult, and will inevitably depend on the exercise of administrative judgment. The Commission intends that the Federal Inspector will be the one to exercise such judgment as he sees fit, and the Commission believes that it has structured the IROR mechanism in a manner which fully authorizes him to do so."

IX. Commission Comments on Abnormal Events not Covered by Change in Scope Rules

The Commission, in Orders 31 and 31-B, commented upon various abnormal events which are not covered by Change In Scope rules and hence, are covered only by the Center Point.

(1) Exclusion From "Wars":

"As to 'wars,' 'we do not include riots, insurrections, actions of public enemy, and civil or military disturbances or other interferences' either because such events are clearly of lesser magnitude than 'war' or because they are inherently vague and ambiguous in meaning."¹

¹Order 31-B, op. cit., page 33.

(2) Design Changes:

"In this instance, the adjective 'major' is essential to the basic structure of the Change in Scope mechanism. Any change in the capacity of the pipeline would probably constitute, on its face, a 'major' change, but that is not true of changes in the route. It is likely that, subsequent to approval of the Final Design but prior to the actual laying of the pipe into the ground, there may well be numerous minor deviations in the precise routing of the pipe - deviations made to accommodate particular terrain conditions as they are encountered. That process is inherent in pipeline construction, and the project sponsors can and should plan for it in their cost estimates."¹

(3) Abnormal Weather, Fires, Floods, "Acts of God":

"The project sponsors should evaluate weather problems realistically (including a factor for delays caused by abnormal weather) when preparing their Certification Cost Estimate (including the Center Point). Then, when abnormal weather occurs, the efforts of all concerned can be focused exclusively on coping with it.

Similarly, fires, floods, landslides and other "acts of God," as well as "terrorism, sabotage, riots, and civil disturbances, and embargos, strikes, work stoppages and slowdowns" are all risks that the project sponsors can evaluate in advance, in the sense of considering a reasonable cost factor for some level of unanticipated and undesirable events that may occur during the course of the project."²

¹Ibid, page 39.

²Order 31, op. cit., page 128.

(4) Delays Due to Non-Completion of Other Segments:

"The IROR mechanism fully protects the project sponsors from one other form of delay that could otherwise have a potentially serious impact on the rate of return. The project sponsors or investors in any one segment, Alaskan or Northern Border, of the pipeline will not be responsible for cost increases resulting from construction delays in the other segments, or from a delay in the initiation of gas production at Prudhoe Bay. This is accomplished by defining the Actual Capital Cost for a segment as those costs incurred up to the point that that segment is capable of rendering service, even though other segments are not yet capable of delivery from Prudhoe Bay. In other words (for IROR purposes only), AFUDC will cease to be added to the Actual Capital Costs for a segment when that segment is complete and ready to begin transporting gas even if, for whatever reason, it is not actually transporting gas. (AFUDC will, of course, continue to accrue for rate base purposes.)"¹

(5) Field Conditions and Right-of-Way:

"With respect to field conditions there is an economic trade-off. Field conditions can be ascertained in advance through sampling and other scientific techniques. On the other hand, there comes a point at which the cost of elaborate advance ascertainment would exceed the cost of coping with whatever unexpected conditions may eventually be encountered. The project sponsors are in the best position to strike the proper balance between incurring the cost of totally comprehensive ascertainment in advance versus coping later with unanticipated conditions that had not been fully ascertained. The project sponsors should be the ones to make the judgement, to estimate their costs accordingly, and to bear the responsibility for whatever unanticipated conditions they eventually encounter. Similarly, right-of-way acquisition is a problem that the project sponsors can and should evaluate when preparing their Certification Cost Estimate (including the Center Point.)"²

¹Ibid, page 133.

²Ibid, pages 128-129.

X Recap of Key Points Related to the Alaska Segment

The Center Point is the Cost Performance Ratio which is associated with the Center Rate of Return. The value of the Center Point is the expected or most likely level of the actual construction costs of the pipeline. The difference between the Center Point and 1.0 is a measure of the expected level of cost overruns from the Projected Capital Costs (PCC) of the project. For the Alaska Segment, the Center Point will be established by review of NWA's Center Point justification paper and not by a formula.

The PCC's initial value is that of the approved Certification Cost Estimate. The PCC may be increased (but not decreased) by the cost of design changes approved by the Federal Inspector prior to the approval of the final design and construction go-ahead. Subsequently, the PCC may be increased by the cost of Change-In-Scope Events as approved by the Federal Inspector.

The abnormal events excluded from coverage by the Center Point are 1) design changes, 2) scope changes, 3) those events covered by the normal contingency allowance (in-scope estimating uncertainty). The abnormal events covered by the Center Point include weather (such as 100 year storms, landslides, major fires and floods), riots, insurrections, terrorism, sabotage, actions of a public enemy, civil disturbances, design changes made subsequent to the Federal Inspector's approval of the Final Design (but prior to the actual laying of the pipe), embargos, strikes, work stoppages and slowdowns.

The IROR will be earned on equity capital and AFUDC earned on borrowed capital. A 25 percent equity capitalization and a 75 percent debt capitalization is assumed.

**PLEASE NOTE: THE PRECEDING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.**

consumption continues to decrease

One of the reasons for the current downturn in demand is the effect of price increases during 1979 and 1980. Real gasoline prices rose more than 50% since the beginning of 1979, while gasoline use during the last 12 months declined 8% from the prior 12-month period.

Some of this decline reflects supply problems in early 1979 caused by the Iranian disruption and Department of Energy allocation rules. But, API pointed out that the reduced level of gasoline use has continued far beyond that period.

Fuel efficiency factor. API also detailed the trend toward greater fuel efficiency in the U.S. auto fleet.

Improvements in fuel efficiency in domestic cars during the past 6 years are partly the result of higher gasoline prices which in turn have given increasing importance to fuel efficiency in vehicle purchase decisions.

And government regulations have been setting higher fuel efficiency standards for automakers.

By itself, however, the supply of more fuel-efficient vehicles has only a partial effect on total gasoline use, API noted.

First, it takes time to replace the existing vehicle fleet. The average age of cars currently in use is about 6 years.

Second, an increase in fuel efficiency of all vehicles on the road wouldn't necessarily result in a match-

ing decline in fuel use. That's because some owners of more fuel-efficient vehicles may use at least part of their fuel efficiency advantage for increased travel rather than translating it entirely into a savings in fuel costs.

Nevertheless, API said, fuel efficiency is becoming an increasingly important factor in vehicle purchase decisions.

Smaller U.S. cars and imports have gained an increasing share of the market in recent years, at the expense of larger cars. Small domestic cars—compacts and subcompacts—and imports have increased their share of retail sales from 38% in 1972 to more than 60% in the first quarter of 1980 on a seasonally adjusted basis.

Other categories. API also reported that total U.S. petroleum deliveries in May declined 1.16 million b/d, or 6.5%, from year-earlier levels.

Unleaded gasoline represented about 43.3% of total motor gasoline deliveries, somewhat less than the 45% share of the previous month. But API said similar small month-to-month reductions have occurred randomly in the past.

As a result of continuing lower product demand and high inventories, crude imports dropped by about 1 million b/d and product imports by 434,000 b/d from May 1979 to May 1980. Imports amount to about 37.8% of current total U.S. supply, compared with 43.5% last year.

Crude stocks, despite the lowest import level since mid-1976, continued to set records and ended the month about 61 million bbl above last year. API said crude inventory levels continue to reflect reduced product demand and refiners' uncertainty about future crude supplies.

Motor gasoline stocks dropped about 11 million bbl last month. But API said month-end inventories have declined from April to May every year for the past 10 years except for 1976 and 1977, with the decreases ranging from 3 million to 19 million bbl.

Distillate stocks increased about 6 million bbl and stand 64 million bbl above last May's level. The current inventory level of 187 million bbl is the highest end-of-May level in the past 10 years, topping the next highest level by about 25 million bbl.

Deliveries of distillate fuel were 436,000 b/d or 14.6% below May 1979 levels. The high inventory level may have had some part in encouraging reduction or delay of distillate purchases.

Other major factors appear to be continued price increases—about 40% in real dollars since last May—and fuel switching.

Total estimated supply during May was 1.1 million b/d below year-earlier levels, reflecting the net effect of a 308,000-b/d increase in domestic supply and a 1.4 million b/d decrease in imports.

FERC reaffirms approval of N. Slope prebuild

ACTING on a rehearing, the Federal Energy Regulatory Commission has reaffirmed its approval of early construction of a portion of the western Lower 48 leg of the Alaska Natural Gas Pipeline System (Angts).

FERC also approved expansion of other pipeline systems to transport additional Canadian gas to southern California as part of a "prebuild" project to aid financing of the 4,800-mile, \$15-25-billion system proposed to move Alaska North Slope gas through Canada to markets in the Lower 48.

FERC now has approved prebuilding of the western and eastern legs of the system in the Lower 48. Both approvals impose dollar limits on the volume of Canadian gas that may be imported to the U.S. before North Slope gas goes on stream.

The project cleared a major hurdle

when three big North Slope producers agreed to pay half of the \$500-million outlay for design, engineering, and final cost estimate of the 743-mile Alaskan segment of the system (OGJ, June 23, Newsletter).

The other half will be paid by Alaskan Northwest Natural Gas Transportation Co., the pipeline group sponsoring the project.

The North Slope producers—Exxon Corp., Standard Oil Co. (Ohio), and Atlantic Richfield Co.—also agreed to participate "in a substantial way" with Alaskan Northwest in financing of the Alaskan line and Prudhoe Bay conditioning plant "upon reasonable terms and conditions."

This part of the agreement provides that the producers aren't placed in the position of becoming the ultimate guarantors of completion of the sys-

tem and that their financial exposure is "effectively limited."

Meanwhile, in Canada, the Foothills pipeline group called for construction bids on the 36-in.-diameter prebuild western leg to be laid in Alberta and British Columbia. Foothills expects to have all government construction approvals in hand shortly.

The entire system—the Alaskan segment and eastern and western legs in Canada and the Lower 48—is scheduled for completion in 1985. It will carry about 2.4 billion cfd of gas to U.S. markets on the West Coast and in the Midwest.

FERC reaffirmation. FERC's latest action backs up its Jan. 11 decision to approve construction of 160 miles of 36-in. loop by Pacific Gas Transmission Corp.

The loop will run from Kingsgate,