

SCOMM

62:1

MAR 17 1989

DAVID F. ASMAN

g-x 3/21/89

Honorable Drue Pearce
Alaska State Senate
Box V
Juneau, Alaska 99811

Dear Drue:

March 14, 1989

The attached TIMES article, pertaining to last Friday's joint meeting of the Senate Resources and Oil & Gas Committees, prompts this missive.

At your early convenience, and if readily available, please send, or cause to be sent, to me copies of the prepared testimony or transcripts of remarks by the following:

- ** Judd Miller, Jr., representing EXXON USA, Inc.;
- ** Byron Grote, representing BP; and
- ** the representative of Northwest Alaskan Pipeline Company (if there was one present).

I'll obtain a copy of Bill McHugh's remarks from him at Yukon Pacific here in Anchorage.

With my thanks for your very kind attention and helpful assistance, and every good wish for your continued success and achievement!

Yours sincerely,

A large, stylized handwritten signature in black ink, appearing to read "D. Asman". The signature is fluid and cursive, with a long horizontal stroke extending to the right.

Attachment

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Exxon says gas market not there

Favors Canadian line when price goes up

by ROBERT LAURIE
Times Juneau Bureau

JUNEAU — Exxon USA Inc. says the best potential market for North Slope gas will be the Lower 48 and that the best way to get it there is by an overland pipeline.

Judd Miller Jr., Exxon's vice president responsible for marketing and transportation of natural gas in the United States, told a Senate panel Friday that the company has "serious reservations about the LNG export project." Exxon owns the rights to 37 percent of the gas produced at Prudhoe Bay.

'All else being equal, LNG from almost anywhere in the world could be delivered more economically to the Far East than North Slope gas.'

Judd Miller Jr.
Exxon USA Inc.

Another major North Slope gas producer last month, BP Exploration, came out in support of Yukon Pacific Corp.'s plan to ship liquified natural gas to the Far East. BP vice president Byron

Grote reiterated that support at the joint meeting of the Senate Resources and Oil and Gas committees Friday afternoon. BP owns the rights to about 20 percent of Prudhoe Bay gas deposits.

The third major North Slope producer, Arco Alaska Inc., has not stated its position publicly.

Yukon Pacific Corp., founded by former Gov. Walter Hickel, is proposing an 800-mile gasline paralleling the trans-Alaska oil pipeline. The gas would be cooled and liquified in Valdez and exported to Pacific Rim countries.

Northwest Alaskan Pipeline Company wants to build a pipeline from the North Slope to the Midwest. Northwest's project, originally proposed in 1976, has been delayed awaiting higher gas prices.

Testifying before the joint meeting, Miller said neither project is viable — yet.

"In reality, neither an overland pipeline to the Lower 48 states nor the export of LNG to Far East markets is economic at today's prices," Miller said.

In a written statement, Miller noted that studies by the American Gas Association and Gas Research Institute conclude that it won't be until after the year 2000 before Lower 48 demand and prices rise high enough for North Slope gas to be economical. Currently there is an oversupply of gas nationwide.

Oil and Gas committee chairwoman Sen. Drue Pearce, R-Anchorage, said she was not surprised by Exxon's testimony, but "disappointed that they don't sound more enthusiastic about any of the projects."

Miller presented a chart to the panel depicting the cost of delivering North Slope gas to Pacific Rim markets versus other suppliers. Miller said, on an investment basis, the \$5.4 billion pricetag of the pipeline has the effect of adding 7,600 miles to the shipping distance. Based on transportation costs, he says North Slope gas is effectively 11,000 miles from Japan — roughly half the circumference of the earth.

"All else being equal, LNG from almost anywhere in the world could be delivered more economically to the Far East than North Slope gas," Miller said.

Using his criteria, he pointed out uncommitted proven reserves "closer" to Japan that total nearly 33 times the amount of known North Slope reserves.

Yukon Pacific President Bill McHugh, testifying earlier, disagreed with Miller's assessment saying "there are no fatal flaws in our project."

Alaska State Legislature

Senator Drue Pearce, Chair

Senator Tim Kelly
Senator Rick Halford
Senator Paul Fischer
Senator Al Adams



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SENATE SPECIAL COMMITTEE ON OIL AND GAS

A G E N D A
MARCH 10, 1989
1:30 PM

SENATE FINANCE - ROOM 518

SUBJECT: UPDATE ON THE SALE OF NORTH SLOPE GAS

- I. JERRY BROSSIA, REGIONAL MANAGER (ON-LINE FROM FAIRBANKS)
STATE PIPELINE COORDINATOR
DIVISION OF LAND & WATER MANAGEMENT, DNR

BILL VAN DYKE, PETROLEUM MANAGER (ON-LINE FROM ANCHORAGE)
DIVISION OF OIL AND GAS, DNR
- II. BOB POE, DIRECTOR
OFFICE OF INTERNATIONAL TRADE
OFFICE OF THE GOVERNOR
- III. CUBA WADLINGTON, VICE PRESIDENT
REGULATIONS AFFAIRS
NORTHWEST ALASKA PIPELINE COMPANY

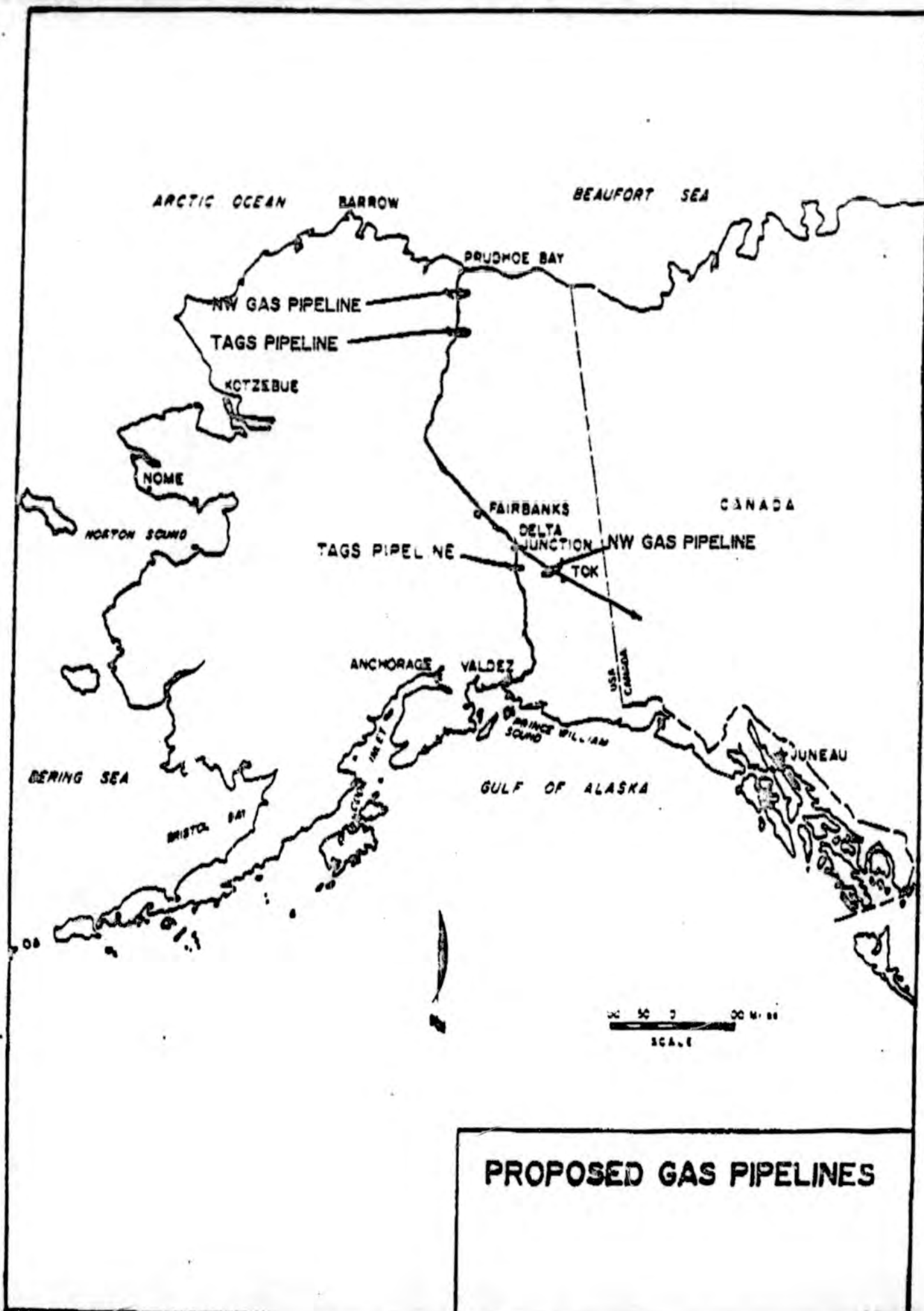
BILL MOSES, GENERAL COUNSEL
NORTHWEST ALASKA PIPELINE COMPANY
- IV. BILL MCHUGH, PRESIDENT, CEO
YUKON PACIFIC CORPORATION

JEFF LOWENFELS, GENERAL COUNSEL
YUKON PACIFIC CORPORATION
- V. BYRON GROTE, VICE PRESIDENT
COMMERCIAL
BP EXPLORATION
- VI. JUDD MILLER, JR., VICE PRESIDENT
EXXON COMPANY, U.S.A.
- VII. DR. JOHN KIM (ON-LINE FROM ANCHORAGE)
ALASKA CENTRAL FOR INTERNATIONAL BUSINESS
UNIVERSITY OF ALASKA, ANCHORAGE

NORTH SLOPE GAS BRIEFING AGENDA

Department of Natural Resources

- I. IntroductionJerry Brossia
Division of Land and Water Management
- II. Location & Status of Proposed Gas Pipelines.....Jerry Brossia
- III. Location & Estimated Quantities of Gas Reserves....Bill Van Dyke
Division of Oil and Gas

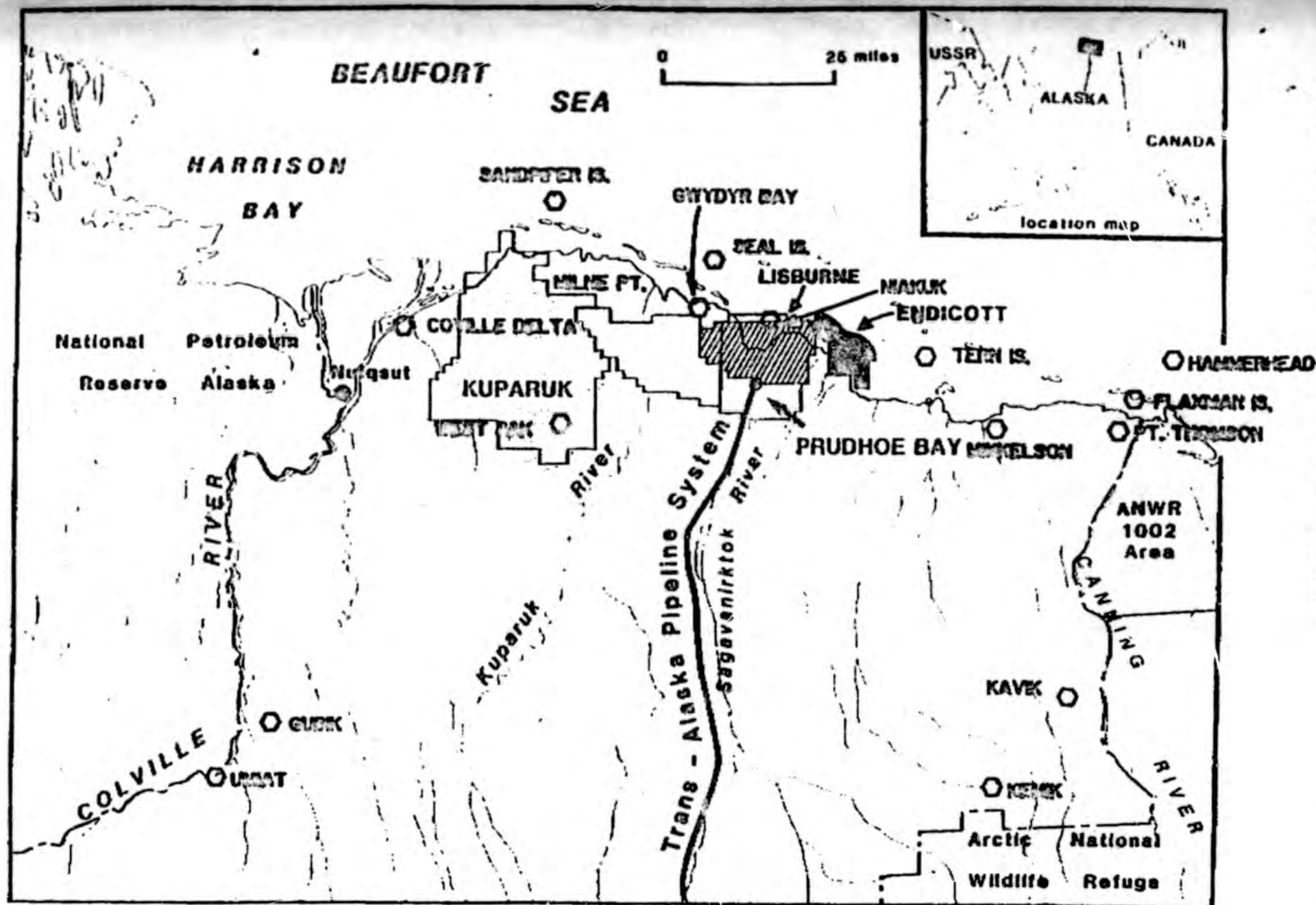


COMPARISON OF ANGTS AND TAGS NATURAL GAS TRANSPORTATION PIPELINES

DNR/DLMM
March 1, 1989

COMPARISON	ANGTS	TAGS
natural gas destination	domestic use to lower 48 states	export to Pacific Rim countries
transportation method	interstate gas pipeline	intrastate gas pipeline + LNG tanker transport
transportation route in Alaska	Prudhoe Bay to Alaska-Canada border	Prudhoe Bay to Anderson Bay in Port Valdez
major project components	48 inch chilled, buried pipeline 15 compressor stations gas conditioning facility	36 inch chilled, buried pipeline 10 compressor stations LNG Plant + marine terminal
pipeline length	745 miles (Alaska segment)	797 miles
quantity of gas/day transported	2.4 billion cubic feet/day	2.3 billion cubic feet/day
estimated cost to construct	\$11.5 billion	\$8 billion
projected revenue to the state	not available	\$477 million over the life of the project
jobs created	not available	10,000 peak, 6,000 average during construction

project status on state land	RW Lease application pending	Conditional RW Lease issued
project status on federal land	RW Grant issued	RW Grant issued



DEVELOPED & UNDEVELOPED GAS DISCOVERIES ON THE NORTH SLOPE

○ DENOTES UNDEVELOPED DISCOVERIES

Developed North Slope Oil and Gas Fields
(As of October 1988)

<u>Field Name</u>	<u>Discovery Date</u>	<u>Estimated Original Recoverable Reserves</u>	<u>Remaining Reserves</u>
Prudhoe Bay	12/67	25,000 BCF 10,800 MMBO	23,000 BCF 4700 MMBO
Kuparuk River	4/69	640 BCF 1340 MMBO	570 BCF 845 MMBO
Prudhoe Bay (Lisburne Pool)	12/67	900 BCF 190 MMBO	890 BCF 150 MMBO
Milne Point	10/69	60 MMBO	55 MMBO
Endicott	3/78	800 BCF 375 MMBO	790 BCF 330 MMBO
S. Barrow	4/49	25.2 BCF	8 BCF
E. Barrow	5/74	12.4 BCF	9 BCF
Totals		27,400 BCF 12,800 MMBO	25,267 BCF 6080 MMBO

BCF - Billion Cubic Feet of Gas
MMBO - Million Barrels of Oil

DO&G Rev. 11/88

Figure 4

Undeveloped North Slope Oil and Gas Discoveries
(As of October 1988)

<u>Name</u>	<u>Discovery Date</u>	<u>Estimated Recoverable Reserves</u>
Umiat	12/46	50 MMBO
Gubik	8/51	600 BCF
E. Umiat	3/63	?
West Sak	4/69	0 - 3000 MMBO
Kavik	11/69	?
Kemik	6/72	?
Flaxman Island	9/75	?
Pt. Thomson	10/77	5000 BCF 300 MMBO
Mikkelson	1978	?
Gwydyr Bay	1981	<10 MMBO
Tern Island	5/83	?
Seal Island	1/84	150 MMBO
Colville Delta	1985	?
Hammerhead	2/86	?
Sandpiper Island	1986	?
Niakuk Discovery	4/85	60 MMBO

BCF - Billion Cubic Feet of Gas
MMBO - Million Barrels of Oil

Totals

**1060 MMBO
5600 BCF**

DO&G Rev. 11/88

Figure 5

DRAFT 3/8/89

ORAL REMARKS OF
CUBA WADLINGTON JR., VICE PRESIDENT FOR REGULATORY AFFAIRS
NORTHWEST ALASKAN PIPELINE COMPANY

ALASKA STATE LEGISLATURE,
SENATE SPECIAL COMMITTEE ON OIL & GAS
AND SENATE RESOURCES COMMITTEE
MARCH 10, 1989

I AM CUBA WADLINGTON JR., VICE PRESIDENT FOR REGULATORY AFFAIRS, NORTHWEST ALASKAN PIPELINE COMPANY, THE AGENT AND OPERATING PARTNER FOR ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY, THE SPONSORS OF THE ALASKAN SEGMENT OF THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM. ACCOMPANYING ME IS OUR GENERAL COUNSEL, WILLIAM J. MOSES.

MADAM CHAIRMAN, THANK YOU FOR THE OPPORTUNITY TO BE HERE TODAY TO GIVE AN UPDATE ON THE A-N-G-T-S PROJECT. VERNON JONES, WHO IS CHAIRMAN OF THE BOARD OF OUR SPONSORING CONSORTIUM, APPEARED HERE BEFORE THE JOINT COMMITTEE ON OIL AND GAS IN MARCH 1984. CONDITIONS HAVE CHANGED IN SEVERAL SIGNIFICANT WAYS OVER THE PAST FIVE YEARS. I'LL EXPLAIN WHY WE NOW HAVE A STRONGLY STRENGTHENED CONVICTION THAT THE PRUDHOE BAY GAS IS NEEDED DOMESTICALLY BY THE UNITED STATES. AND I'LL EXPLAIN WHY WE HAVE RENEWED OPTIMISM THAT TIME IS BRINGING US CLOSER TO PROJECT REMOBILIZATION.

ON JANUARY 24TH OF THIS YEAR, WE APPEARED IN ANCHORAGE BEFORE A PUBLIC CONFERENCE HELD BY THE ECONOMIC REGULATORY

ADMINISTRATION OF THE U.S. DEPARTMENT OF ENERGY. OUR PREPARED STATEMENTS AT THAT CONFERENCE PROVIDE AN UP-TO-DATE ELABORATION OF OUR OUTLOOK FOR THE ANGTS PROJECT. THEY ARE BY VERNON JONES, MYSELF, AND BY MR. JAMES JENSEN WHO IS A RECOGNIZED AUTHORITY ON OIL AND GAS ECONOMICS AND DEVELOPMENT. IN ADDITION, WE LATER FILED SUPPLEMENTAL COMMENTS WITH THE ECONOMIC REGULATORY ADMINISTRATION WHICH, I BELIEVE, ALSO PROVIDE VALUABLE BACKGROUND INFORMATION.

WITH YOUR CONCURRENCE, I WOULD LIKE TO PLACE THESE FOUR DOCUMENTS IN THE RECORD AND THEN MAKE A BRIEF ORAL STATEMENT. I HAVE EXTRA COPIES WITH ME FOR COMMITTEE MEMBERS AND STAFFS.

THE U.S. SPONSORS OF THE ALASKAN SEGMENT OF ANGTS HAVE INVESTED ABOUT \$ 1.5 BILLION JUST ON THE ALASKAN SEGMENT OF THE SYSTEM. THIS INVESTMENT IS IN DESIGN, PRELIMINARY ENGINEERING, SATISFYING GOVERNMENT REQUIREMENTS, AND CONSTRUCTION PLANNING. WE MADE THIS EXPENDITURE IN GOOD FAITH, BASED ON A FRAMEWORK OF FEDERAL LAW. THIS INCLUDED EXPLICIT COMMITMENTS TO AN OVERLAND TRANSPORTATION SYSTEM TO BRING THE 26 TRILLION CUBIC FEET OF PROVED PRUDHOE BAY GAS RESERVES TO THE LOWER 48 STATES.

WE REMAIN DEDICATED TO COMPLETING THIS PROJECT AT THE EARLIEST FEASIBLE DATE WHEN THE GAS CAN BE SOLD WITHOUT GOVERNMENT SUBSIDY, AT MARKET CLEARING-PRICES. THAT DATE IS APPROACHING MUCH FASTER THAN IS GENERALLY REALIZED.

THE FIRST KEY ISSUE THAT I'LL DISCUSS IS "NEED." IS THERE A DOMESTIC REQUIREMENT FOR THE GAS DURING THE PERIOD STARTING ABOUT 1996?

OUR CONCEPT OF DOMESTIC "NEED" FOR THE ALASKAN GAS IS BASED ON AN ECONOMIC TEST. IF THE GAS IS REASONABLY EXPECTED TO BE SALEABLE ON A FREE-MARKET BASIS IN THE LOWER-48 STATES, WITHOUT GOVERNMENT SUBSIDY, THEN IT MEETS THIS PRIMA FACIE TEST. BY DEFINITION, IF COMPETITIVELY-PRICED ALASKAN GAS IS NOT AVAILABLE, DEMAND FOR THAT ENERGY COULD BE MET ONLY IF AMERICAN CONSUMERS MAKE USE OF HIGHER PRICED AND/OR LESS DESIRABLE ALTERNATIVES.

THE CURRENTLY PROVED PRUDHOE BAY GAS RESERVES, DELIVERED TO THE LOWER-48 STATES BY A PIPELINE SYSTEM, CAN MEET THIS FREE-MARKET TEST BASED ON SIX KEY CONSIDERATIONS:

--FIRST: THE COST OF THE ANGTS. THE RECENTLY REVISED COST ESTIMATE FOR THE REMAINING ELEMENTS OF THE ANGTS WILL MAKE THE DELIVERED GAS PRICE HIGHLY COMPETITIVE DOMESTICALLY IN THE YEARS AHEAD. I WILL ELABORATE ON THIS LATER.

--THE SECOND BASIS FOR DOMESTIC NEED IS A VARIETY OF INDEPENDENT SUPPLY/DEMAND FORECASTS. REASONABLE PROJECTIONS OF A DOMESTIC "NEED" FOR THE ALASKAN GAS DURING THE YEARS AHEAD HAVE BEEN MADE BY A NUMBER OF INDEPENDENT, RESPECTED ANALYTICAL ORGANIZATIONS SUCH AS THE GAS RESEARCH INSTITUTE.

A NEW, VERY RECENT STUDY IS ATTACHED TO THE PREPARED STATEMENT OF VERNON T. JONES, WHICH HAS BEEN PLACED IN YOUR RECORD. IT LENDS ADDITIONAL WEIGHT TO OUR POSITION. THE STUDY WAS PREPARED BY THE WASHINGTON POLICY AND ANALYSIS CONSULTING GROUP UNDER THE DIRECTION OF A FORMER DEPUTY SECRETARY OF ENERGY.

ALL OF THESE SUPPLY/DEMAND STUDIES HAVE ONE THING IN COMMON: THEY PROJECT A VERY REAL NEED FOR THE PRUDHOE BAY GAS IN THE LOWER-48 STATES BY THE YEAR 2010 AT THE VERY LATEST.

--THE THIRD BASIS FOR DOMESTIC NEED IS U.S. NATIONAL ENERGY SECURITY. DOMESTIC DEMAND FOR NATURAL GAS IS ALMOST CERTAIN TO GROW BEYOND CURRENT FORECASTS DUE TO THE RAPIDLY INCREASING U.S. DEPENDENCE ON FOREIGN OIL, NOW OVER 40% AND EXPECTED TO BE ABOUT 70% BY 2010. LET ME REPEAT THAT: 70% DEPENDENT UPON FOREIGN OIL IMPORTS BY THE YEAR 2010! THAT IS AN ALARMING FIGURE, AND IT SHOULD BE OF CONCERN TO ALL AMERICANS. OUR NATION OBVIOUSLY WILL BECOME DANGEROUSLY VULNERABLE TO OIL SUPPLY DISRUPTIONS AND/OR PRICE SHOCKS. MUCH GREATER USE OF DOMESTIC NATURAL GAS PREDICTABLY WILL BECOME A PUBLIC POLICY IMPERATIVE AS AN IMPORTANT MEANS TO LIMIT THIS VULNERABILITY. THE WASHINGTON POLICY AND ANALYSIS STUDY CONCLUDES THAT GREATER DOMESTIC USE OF NATURAL GAS CAN RESULT IN A 2 MILLION BARREL PER DAY REDUCTION IN DEMAND FOR IMPORTED OIL. THE REPORT INDICATES THAT ALASKAN PIPELINE GAS IS NEEDED TO MAKE THIS POSSIBLE. THE ANGTS, AT FULL CAPACITY, WILL PROVIDE THE ENERGY EQUIVALENT OF 30 PERCENT OF THIS TOTAL--600,000 BARRELS OF OIL PER DAY. THAT'S AN IMPRESSIVE CONTRIBUTION TO U.S. ENERGY SECURITY BY ANY MEASURE.

PRESIDENT BUSH, IN ADDRESSING WAYS TO ENHANCE U.S. NATIONAL SECURITY LAST YEAR, DECLARED: QUOTE. THERE'S NO SECURITY FOR THE UNITED STATES IN FOREIGN OIL. . . WE MUST TURN TO ALTERNATIVES LIKE NATURAL GAS. UNQUOTE.

--THE FOURTH BASIS FOR DOMESTIC NEED IS ENVIRONMENTAL REQUIREMENTS. CONCERN IS GROWING ABOUT ACID RAIN, GROUND-LEVEL OZONE, CARBON MONOXIDE, ATMOSPHERIC PARTICULATES, AND THE SO-CALLED GREENHOUSE EFFECT. INCREASED USE OF NATURAL GAS CLEARLY CAN IMPROVE THE SITUATION. MORE STRINGENT STANDARDS APPEAR

INEVITABLE AND WILL RESULT IN INCREASED DEMAND FOR NATURAL GAS. THE WASHINGTON POLICY AND ANALYSIS STUDY THAT I'VE MENTIONED CONCLUDES, AND I QUOTE: A MAJOR FORCE DRIVING THE INTRODUCTION OF MORE NATURAL GAS INTO THE U.S. ECONOMY IN THE FUTURE COULD BE AN EFFORT TO MEET ENVIRONMENTAL STANDARDS IN THE MOST COST-CONSCIOUS MANNER. UNQUOTE.

BUT AN EVEN MORE COMPELLING CASE IS MADE IN A COMBINED REPORT BY THE NATIONAL ACADEMY OF SCIENCES, THE NATIONAL ACADEMY OF ENGINEERING AND THE INSTITUTE OF MEDICINE, TO PRESIDENT BUSH. AND I QUOTE:

. . . WE SHOULD EXPLORE MEANS FOR REDUCING ENERGY DEMAND WITHOUT ~~IMPEDING~~ ECONOMIC GROWTH, FOR EXAMPLE, BY USING FOSSIL FUELS WITH GREATER EFFICIENCY, AS WELL AS INCENTIVES AND OTHER MEANS TO INCREASE USE OF THE 'CLEANEST' FOSSIL FUELS SUCH AS NATURAL GAS. UNQUOTE.

--THE FIFTH BASIS OF DOMESTIC NEED IS THAT IMPORTS OF NATURAL GAS WILL NOT BE ENOUGH TO SATISFY DOMESTIC REQUIREMENTS. IT IS UNREALISTIC TO ASSUME THAT U.S. IMPORTS OF GAS FROM CANADA, MEXICO, OR OF LNG CAN BE OBTAINED ESSENTIALLY WITHOUT LIMITATION, INDEFINITELY AND AT MORE ATTRACTIVE PRICES THAN ALASKAN PIPELINE GAS. CREDIBLE FORECASTS WHICH TAKE BOTH PRICE AND AVAILABILITY INTO CONSIDERATION CALL FOR GAS FROM AN ALASKAN PIPELINE IN ADDITION TO SUBSTANTIALLY INCREASED LNG IMPORTS AND CANADIAN GAS.

THE CANADIAN NATIONAL ENERGY BOARD RECENTLY RELEASED A REVISED ENERGY SUPPLY AND DEMAND FORECAST. IT SHOWS CLEARLY THERE WILL HAVE TO BE INCREASING RELIANCE IN CANADA UPON GAS FROM

"FRONTIER" AREAS STARTING IN THE LATE 1990'S. ABOUT 1.2 BILLION CUBIC FEET OF GAS PER DAY FROM THE MACKENZIE DELTA AND ARCTIC ISLANDS, WHICH WILL HAVE MANY OF THE SAME ECONOMIC COSTS THAT THE BUILDERS OF THE ANGTS FACE IN CONSTRUCTING A PIPELINE FROM THE NORTH SLOPE, WILL PROBABLY START FLOWING BEFORE THE YEAR 2000.

SUBSTANTIAL MEXICAN IMPORTS, HOWEVER, DO NOT APPEAR LIKELY. MEXICAN GOVERNMENT POLICY IS TO MAXIMIZE THE USE OF NATURAL GAS DOMESTICALLY.

REGARDING LNG IMPORTS, WHEN THE LIMITED UNUSED CAPACITY IN EXISTING DOMESTIC TERMINALS IS USED UP, ANY ADDITIONAL CAPACITY CAN THEN ONLY BE OBTAINED BY A COSTLY, CONTROVERSIAL AND PROTRACTED PROCESS OF SITING AND ENVIRONMENTAL APPROVALS OF MAJOR NEW TERMINALS.

IT SEEMS CLEAR, THEREFORE, THAT THE U.S. GAS MARKET WILL BE SERVED BY A VARIETY OF SOURCES, EACH WITH ITS LIMITATIONS. IN SUCH AN ENVIRONMENT, THE OVERLAND DELIVERY OF THE PRUDHOE BAY RESERVES SHOULD BE HIGHLY COMPETITIVE. AGAIN, EACH OF THESE SOURCES WILL BE NEEDED TO MEET DOMESTIC DEMAND.

--THE SIXTH AND FINAL BASIS FOR DOMESTIC NEED IS A PROJECTED ELECTRIC POWER GENERATION SHORTFALL IN THE UNITED STATES. THIS HAS MAJOR IMPLICATIONS FOR DOMESTIC GAS DEMAND. THERE IS A VERY SERIOUS POTENTIAL SHORTFALL OF ELECTRIC POWER GENERATION CAPABILITY IN THE U.S. IN THE NEXT TEN YEARS AND ON INTO THE NEXT CENTURY. NATURAL GAS TURBINES CAN BE CONSTRUCTED QUICKLY AND AT FAR LESS COST THAN ANY TYPE OF STEAM-GENERATION PLANT. THEY ARE PROBABLY THE ONLY REALISTIC WAY TO AVERT POWER SHORTAGES.

THE U.S. ENERGY INFORMATION ADMINISTRATION RECENTLY PROJECTED A BASE-CASE NEED FOR ABOUT 127 GIGAWATTS OF ADDITIONAL ELECTRIC GENERATING CAPACITY BY THE YEAR 2000, INCLUDING ABOUT 33 GIGAWATTS CURRENTLY UNDER CONSTRUCTION. THIS TOTAL IS EQUIVALENT TO BUILDING ABOUT 127 MAJOR NUCLEAR POWER GENERATING PLANTS IN THE NEXT DECADE.

THE SIGNIFICANCE OF THIS PROJECTION IS THE 10- TO 12-YEAR LEAD TIME REQUIRED FOR REGULATORY APPROVAL AND CONSTRUCTION OF NEW STEAM GENERATION PLANTS. OBVIOUSLY, THE LEAD TIME FOR SUCH CONSTRUCTION IS BEING DISSIPATED BY EVERY PASSING MONTH. IN THE MEANTIME, NATURAL GAS COMBINED-CYCLE OR COMBUSTION TURBINES ARE RAPIDLY TAKING OVER THE MAJOR SHARE OF FUTURE PLANNED CONSTRUCTION.

THE PLAIN RESULT OF THIS GROWING RELIANCE UPON NATURAL GAS FOR ELECTRIC POWER GENERATION HAS NOT YET BEEN FULLY REFLECTED IN MOST SUPPLY AND DEMAND PROJECTIONS. THE RECENT WASHINGTON POLICY AND ANALYSIS REPORT I'VE MENTIONED, HOWEVER, STATES, AND I QUOTE:

. . . WE FELT CONFIDENT WITH A DETAILED ANALYSIS THAT SHOWED GAS SUPPLYING NEARLY ONE-SIXTH OF THE PRIMARY ENERGY USED IN GENERATING ELECTRICITY BY 2010. THIS ALONE WOULD REQUIRE ABOUT 6 TRILLION CUBIC FEET OF GAS ANNUALLY, OR MORE THAN TWICE AS MUCH AS IS BEING USED NOW BY THE ELECTRICITY INDUSTRY. UNQUOTE

A UNIQUE ATTRIBUTE OF THE PROVEN PRUDHOE BAY RESERVES, DUE TO THEIR MAGNITUDE, IS THE ABILITY TO SUPPLY A LONG-TERM -- UP TO AT LEAST 25 YEARS -- ASSURED SOURCE OF SUPPLY FOR THE

CONSTRUCTION AND FINANCING OF BASELOAD ELECTRIC GENERATING PLANTS.

IN SUMMARY OF DOMESTIC NEED, WE BELIEVE THAT BY ANY REASONABLE ASSESSMENT, THE PRUDHOE BAY GAS RESERVES WILL BE NEEDED BY AMERICAN CONSUMERS DURING A PERIOD COMMENCING ABOUT 1996.

THE REASONABLY PROJECTED DOMESTIC NEED FOR PRUDHOE BAY'S PROVEN GAS RESERVES SHOULD BY ITSELF BE SUFFICIENT TO DEMONSTRATE THAT GOVERNMENT AUTHORITIES AT ALL LEVELS SHOULD AVOID ANY ACTION THAT MIGHT JEOPARDIZE THE OVERLAND DELIVERY OF THAT GAS TO AMERICAN CONSUMERS. THERE ARE, IN ADDITION, TWO OTHER IMPORTANT CONSIDERATIONS.

FIRST: THERE IS SIMPLY NOT ENOUGH PROVED AND ECONOMICALLY TRANSPORTABLE GAS RESERVES ON THE NORTH SLOPE TO WARRANT CONSTRUCTION OF TWO MAJOR GAS CONDITIONING PLANTS AND TWO LARGE-DIAMETER PIPELINE SYSTEMS IN THE SAME TIME FRAME.

THE ONLY BASIS UPON WHICH A MAJOR GAS TRANSPORTATION SYSTEM CAN BE FINANCED AND CONSTRUCTED IS PROVED RESERVES. PROVED RESERVES, AS YOU KNOW, ARE SOMETHING ENTIRELY DIFFERENT FROM UNDISCOVERED RESOURCES AND OTHER SPECULATIVE CATEGORIES OF POTENTIAL GAS FINDINGS.

THE ANGTS HAS ALWAYS RELIED UPON THE 26 TCF OF PROVED GAS RESERVES AT PRUDHOE BAY, NOTABLY GAS ASSOCIATED WITH THE PRODUCTION OF OIL AND THEN REINJECTED INTO THE PRUDHOE BAY FIELD. THIS IS WELL ESTABLISHED IN THE PRESIDENT'S DECISION OF SEPTEMBER 1977 AND ELSEWHERE IN THE REGULATORY RECORD. THIS GAS REQUIRES MINIMAL GATHERING OR PRODUCTION EXPENDITURES. MOREOVER,

IT IS CONCENTRATED IN A SMALL AREA WITH SUBSTANTIAL EXISTING SUPPORT FACILITIES. FOR THESE REASONS, TOGETHER WITH THE LARGE QUANTITY OF PROVEN RESERVES, GAS IN THE GENERAL PRUDHOE BAY AREA--INCLUDING THE ENDICOTT, KUPARUK, AND LISBURNE RESERVOIRS--IS TRULY THE "CREAM" OF WHATEVER GAS RESOURCES MAY EXIST ON THE NORTH SLOPE. THESE CONSIDERATIONS WOULD BE IMPORTANT IN MOST OTHER PARTS OF THE WORLD. BUT THEY ARE OF CRITICAL IMPORTANCE TO ECONOMIC VIABILITY IN THE ARCTIC. WITH RESPECT TO ANY OTHER POTENTIAL, BUT UNPROVEN OR UNDEVELOPED NORTH SLOPE GAS SOURCES, WE CAN SAY WITH REASONABLE CONFIDENCE THAT--EVEN UNDER THE BEST OF CIRCUMSTANCES--UNCERTAINTIES AS TO GAS AVAILABILITY, TRANSPORTABILITY, AND COSTS WILL DELAY ANY MAJOR PIPELINE PROJECT RELYING ON SUCH POTENTIAL ALTERNATIVES UNTIL LONG AFTER A PROJECT USING THE PRUDHOE BAY GAS COMES ON STREAM.

AS INDICATED BY THE EXPERT TESTIMONY OF MR. JAMES JENSEN OF JENSEN ASSOCIATES, INC., WHOSE STATEMENT I'VE PLACED IN YOUR RECORD, THE CHOICE IS CLEAR FOR THE REASONABLY FORESEEABLE FUTURE, EXTENDING WELL INTO THE NEXT CENTURY: EITHER GAS WILL BE AVAILABLE FOR AMERICAN CONSUMERS WHEN NEEDED OR PRUDHOE BAY GAS WILL BE COMMITTED TO SOME OTHER LARGE-SCALE PURPOSE, BUT NOT BOTH.

A SECOND MAJOR CONSIDERATION FOR GOVERNMENT AUTHORITIES IS THE BODY OF UNRESOLVED LEGAL ISSUES RAISED BY YUKON PACIFIC CORPORATION'S PROPOSED EXPORT PROJECT. THESE ISSUES NO DOUBT WILL HAVE TO BE RESOLVED BY THE FEDERAL COURTS. I WILL NOT FURTHER ELABORATE OTHER THAN TO REEMPHASIZE THAT THE ANGTS SPONSORS HAVE ALREADY INVESTED ABOUT \$1.5 BILLION DOLLARS IN GOOD

FAITH RELIANCE ON EXPLICIT GOVERNMENT REPRESENTATIONS. WE WILL TAKE ALL NECESSARY ACTIONS IN THE APPROPRIATE FORUMS TO PROTECT THE SPONSORS' INTERESTS IN THAT INVESTMENT AND WILL CONTINUE TO WORK TOWARD THE STATED NATIONAL OBJECTIVE OF PROVIDING PRUDHOE BAY GAS TO LOWER-48 CONSUMERS AT THE EARLIEST OPPORTUNITY.

I SAID EARLIER THAT I WOULD ELABORATE ON THE REVISED COST ESTIMATE FOR THE ANGTS. THE DELIVERED GAS PRICE TO THE LOWER-48 STATES IS A CRITICAL DETERMINANT OF FEASIBILITY AND TIMING OF AN OVERLAND PIPELINE SYSTEM FROM ALASKA. I'LL NOW EXPLAIN WHY WE'RE CONFIDENT THAT THE PRUDHOE BAY GAS WILL BE SALABLE TO AMERICAN CONSUMERS ON A FREE-MARKET BASIS, WITHOUT GOVERNMENT SUBSIDY, DURING THE PERIOD 1996 TO 2021.

I WILL FIRST REVIEW THE PRICES PROJECTED FOR IMPORTS BY THE U.S. OF PIPELINE GAS AND LNG SO THAT WE HAVE A BASIS FOR DETERMINING WHETHER THE ANGTS GAS REASONABLY COULD BE COMPETITIVE WITH THESE POTENTIAL ALTERNATIVES.

THE GAS RESEARCH INSTITUTE, A WELL-RECOGNIZED ANALYTICAL ORGANIZATION, HAS FORECAST "ACQUISITION PRICES" AT THE U.S. BORDER FOR BOTH PIPELINE IMPORTS AND LNG OF \$3.20 PER MILLION BTUs IN 1995, \$3.32 IN 1996 AND ABOUT \$6.50 IN THE YEAR 2010. ALL OF THESE PRICES ARE EXPRESSED IN CONSTANT 1987 DOLLARS.

A RISING TREND IN REAL PRICE--THAT IS, IN ADDITION TO ANY INCREASES IN THE GENERAL PRICE LEVEL DUE TO INFLATION--IS CLEARLY EVIDENT. IT IS IMPORTANT TO NOTE THAT GRI FORECASTS AN INCREASING TOTAL DOMESTIC DEMAND FOR NATURAL GAS THROUGH 2010 DESPITE THIS INCREASE IN REAL PRICES. WITH THESE FIGURES AS A BACKGROUND FOR COMPARISON PURPOSES, I WILL ADDRESS THE PRICE AND

MARKETABILITY OF ALASKAN GAS AS DELIVERED BY PIPELINE THROUGH CANADA TO THE U.S. BORDER.

BEFORE DOING SO, I WOULD OBSERVE THAT EXPERT GAS MARKET ANALYSTS REASONABLY MIGHT DIFFER OVER ANY PARTICULAR FORECAST OF GAS PRICES, WHICH NECESSARILY IS BASED ON ASSUMPTIONS REGARDING FUTURE ECONOMIC GROWTH, WORLD OIL PRICES, ETC.

OF OVERRIDING IMPORTANCE, HOWEVER, IS THE FACT THAT THERE IS A CONSENSUS AMONG QUALIFIED OBSERVERS THAT THE REAL PRICE OF BOTH LOWER-48 GAS PRODUCTION AND GAS IMPORTS WILL RISE OVER THE YEARS AHEAD. ONLY THE RATE OF INCREASE MAY DIFFER. THIS FACT, AS I WILL DEMONSTRATE, VIRTUALLY ASSURES THE DOMESTIC MARKETABILITY OF ALASKAN PIPELINE GAS AND LEAVES OPEN ONLY THE QUESTION OF SPECIFIC TIMING.

NOW, THE SALABILITY OF ALASKAN PIPELINE GAS OBVIOUSLY WILL BE DETERMINED BOTH BY THE CAPITAL COSTS OF THE PIPELINE SYSTEM AND THE WELLHEAD PRICE OF THE GAS.

IN MAY 1988, THE U.S. AND CANADIAN SPONSORS OF THE ANGTS COMPLETED AN IMPORTANT REESTIMATE OF THE CAPITAL COST OF THE REMAINING ELEMENTS OF THE ANGTS. THE STUDY DREW UPON AN EXTENSIVE BODY OF PROPRIETARY AND CONFIDENTIAL INFORMATION DEVELOPED SINCE OUR EARLIER COST ESTIMATES PREPARED IN THE LATE 1970s AND EARLY 1980s. IT TOOK INTO CONSIDERATION:

--ADVANCES IN PIPELINE DESIGN,

--INFORMATION GATHERED FROM EXTENSIVE FIELD TESTING PROGRAMS AND OPTIMIZATION STUDIES CONDUCTED BY THE PROJECT SPONSORS, AND

--SIGNIFICANT CHANGES IN THE ECONOMIC CLIMATE.

THE RESULT WAS A DRAMATICALLY LOWER COST ESTIMATE, RESULTING IN PART FROM THE FOLLOWING:

- REDUCED CONSTRUCTION SCHEDULE,
- IMPROVED WELDING TECHNOLOGY,
- MORE TRADITIONAL OWNER/CONTRACTOR FUNCTIONS,
- USE OF EXISTING COMMUNICATION SYSTEMS,
- REDUCED CONTINGENCY ALLOWANCES,
- HIGHER PRESSURE, SMALLER DIAMETER MAINLINE PIPE, BUT
HIGHER GAS THROUGHPUT, AND
- MORE MODEST ASSUMPTIONS ABOUT THE RATE OF INFLATION AND
INTEREST RATES.

EXPRESSED IN 1988 DOLLARS, THE CAPITAL COST OF THE PROJECT, INCLUDING THE NORTH SLOPE CONDITIONING PLANT, TOGETHER WITH THE REMAINING PIPELINE SEGMENTS IN ALASKA, CANADA AND THE LOWER-48 STATES, WAS ESTIMATED AT \$14.6 BILLION, COMPARED TO \$26.1 BILLION IN THE EARLIER ESTIMATE--APPROXIMATELY A 45% REDUCTION. THIS, IN TURN RESULTED IN A NEW, LOWER COST OF THE PIPELINE DELIVERY SERVICE.

BASED ON THE NEW CAPITAL COST ESTIMATE, THE TRANSPORTATION COST OF DELIVERING ALASKAN GAS TO THE LOWER-48 STATES IS \$2.44 PER MILLION BTUs IN THE YEAR 1996, EXPRESSED IN 1987 DOLLARS.

WITH A REASONABLE ALLOWANCE FOR THE WELLHEAD PRICE OF THE GAS ADDED, THE ALASKAN GAS OBVIOUSLY WOULD BE COMPETITIVE WITH THE PROJECTED PRICE IN 1996 OF \$3.32 FOR IMPORTS AND LNG THAT I MENTIONED EARLIER.

UP TILL NOW, I'VE USED A 1996 INITIAL IN-SERVICE DATE AS AN EXAMPLE. THE ANGTS GAS WOULD BE COMPETITIVE AT THAT TIME BASED

ON THE PROJECTED PRICES; HOWEVER, THE SPECIFIC DATE THAT THE ALASKAN GAS WILL FLOW WILL BE DETERMINED BY ACTUAL DEVELOPMENTS IN THE MARKET PLACE, INCLUDING THE WORLD PRICE OF OIL. IN THIS REGARD, SEVERAL KEY FACTORS WILL MAKE THE ANGTS GAS MUCH MORE SALABLE AS TIME PASSES. THEY ARE:

- FIRST, THE CAPITAL COSTS OF THE "PREBUILT," OPERATING PORTIONS OF THE SYSTEM--ABOUT 1/3 OF THE TOTAL MILEAGE--CONTINUE TO BE DEPRECIATED. THIS RESULTS IN A PROGRESSIVELY LOWER TRANSPORTATION COST OF SERVICE, AND
- SECOND, AS I'VE PREVIOUSLY STATED, THE REAL COST OF GAS IMPORTS, LNG, AND OTHER ALTERNATIVES IS PROJECTED BY MOST OBSERVERS TO RISE SUBSTANTIALLY OVER TIME. ON THE OTHER HAND, BOTH THE PRUDHOE BAY GAS PRICE AND PIPELINE CONSTRUCTION COSTS SHOULD REMAIN ESSENTIALLY LEVEL IN REAL DOLLAR TERMS. THE PRUDHOE BAY GAS, IT SHOULD BE NOTED, WILL INCUR VIRTUALLY NO ADDITIONAL PRODUCTION OR GATHERING COSTS. THE NET EFFECT IS TO MAKE ALASKAN PIPELINE GAS PROGRESSIVELY MORE ATTRACTIVE THAN POTENTIAL ALTERNATIVES IN THE YEARS AHEAD.

THE ANGTS SPONSORS RECOGNIZE CLEARLY THE RADICALLY ALTERED DOMESTIC GAS MARKET TODAY AS COMPARED TO THE LATE 1970S WHEN THE ALASKA GAS PIPELINE PROJECT WAS INITIATED. AT THAT TIME, A HANDFULL OF MAJOR INTERSTATE GAS TRANSMISSION COMPANIES PLANNED TO PURCHASE THE PRUDHOE BAY GAS FOR RESALE FROM THEIR OWN INVENTORY. EVEN THEN, IT WAS DETERMINED THAT THIS GAS WOULD BE ACCESSIBLE TO LOCAL DISTRIBUTION COMPANIES IN 47 OF THE LOWER-48 STATES. TODAY, WITH THE EMPHASIS ON OPEN ACCESS TO

TRANSPORTATION SERVICES, WE EXPECT AN EVEN MORE WIDELY SPREAD UTILIZATION.

WE HAVE MENTIONED PREVIOUSLY THAT THE LONG-TERM, ASSURED SOURCE OF SUPPLY REPRESENTED BY THE PRUDHOE BAY GAS IS HIGHLY ATTRACTIVE. THESE ATTRIBUTES ARE PARTICULARLY IMPORTANT AS GAS INCREASINGLY BECOMES THE FUEL OF CHOICE FOR MAJOR ELECTRIC GENERATING PLANTS. THE SUCCESSFUL FINANCING OF MAJOR COMBINED-CYCLE AND COMBUSTION TURBINE GAS PLANTS REQUIRES ASSURANCE OF GAS SUPPLY AND REASONABLY PREDICTABLE PRICES. THE ALASKAN GAS, THROUGH THE ANGTS, CAN MEET THAT REQUIREMENT.

AS THE SO-CALLED GAS "BUBBLE" DISSIPATES OVER THE NEXT TWO YEARS, AS MOST RESPONSIBLE OBSERVERS PREDICT, THE SPOT MARKET FOR GAS PURCHASES IS LIKELY TO BECOME MORE UNPREDICTABLE AND, THEREFORE, LESS ATTRACTIVE. UNDER THESE CIRCUMSTANCES, WE FORESEE A RENEWED RECEPTIVENESS TO LONG-TERM SUPPLY ARRANGEMENTS, WHICH WILL SUPPORT BUILDING THE ANGTS.

IN SUMMARY, ALASKAN PIPELINE GAS, BASED ON REASONABLE PRICE PROJECTIONS FOR POTENTIAL ALTERNATIVES, SHOULD BE VERY SALABLE IN THE DOMESTIC MARKET DURING THE PERIOD COMMENCING ABOUT 1996. THE DELIVERED GAS WILL BE INCREASINGLY COMPETITIVE EACH YEAR THAT PASSES FROM 1996 FORWARD INTO THE NEXT CENTURY AS THE REAL PRICES OF ALTERNATIVES CONTINUE TO RISE.

IN CLOSING, I WANT TO REITERATE THE ANGTS SPONSORS' CONVICTION THAT THE PRUDHOE BAY GAS RESERVES WILL BE NEEDED BY AMERICAN CONSUMERS. ONLY THE PRECISE TIMING OF AN OVERLAND PIPELINE DELIVERY SYSTEM CANNOT BE SPECIFIED. ONE FINAL NOTE: WE ARE VERY MUCH AWARE OF YOUR INTEREST, ALONG WITH MOST OTHER

ALASKANS, IN SEEING THE NORTH SLOPE GAS BROUGHT TO MARKET AT THE EARLIEST POSSIBLE DATE. WE SHARE THAT INTEREST. WE SINCERELY BELIEVE THAT AN OVERLAND PIPELINE SYSTEM TO SERVE THE DOMESTIC U.S. MARKET REMAINS THE BEST AND THE EARLIEST POSSIBILITY TO MEET THAT OBJECTIVE. THANK YOU AGAIN MADAM CHAIRMAN.

STATEMENT OF JUDD MILLER, JR.
VICE PRESIDENT, EXXON COMPANY, U.S.A.
BEFORE THE SENATE SPECIAL COMMITTEE ON OIL AND GAS
ALASKA STATE LEGISLATURE
MARCH 10, 1989

My name is Judd Miller, Jr., Vice President of Exxon Company, U.S.A. I am responsible for Exxon's marketing and transportation of natural gas in the United States. Exxon appreciates the opportunity to testify at this hearing today on the prospects of commercializing North Slope gas.

Summary

Substantial gas reserves exist on the North Slope of Alaska. Exxon, like the state and its citizens, has a substantial interest in seeing these reserves commercialized. However, the reserves are far distant from any market. The transportation system required will be huge both in scope and magnitude of dollars required with a long lead time needed to bring the project into operation. Before such a project can move forward there must be evidence of markets and prices sufficient to provide reasonable assurance to the many participants that the investment will be sound. Today, neither an overland pipeline to the lower 48 states nor the export of liquified natural gas (LNG) to Far East markets is economic. Real growth in energy prices and in market demand will be necessary before any project to move North Slope gas reserves to market can be economic.

Since the discovery of the Prudhoe Bay field over 20 years ago, Exxon has considered and reconsidered many alternative methods of commercializing the gas reserves including a pipeline to the lower 48 states, liquefaction and shipment to domestic or foreign markets, and less conventional alternatives such as chemical conversion to methanol or petrochemical facilities at a south Alaska tidewater location. Based on these studies, Exxon believes that the best market for Alaska's North Slope gas will be the lower 48 states and that an overland pipeline will be the best mode of transportation to that market. We have serious concerns that LNG made from North Slope gas would not be competitive in Far East markets because of the large and unique pipeline investment required; an investment that competing LNG suppliers in the Far and Middle East would not incur.

Nevertheless, the Trans-Alaska Gas System (TAGS) sponsors are to be complimented for their efforts to develop an outlet for North Slope gas. Although we have serious reservations about the LNG export project, Exxon does not want to discourage anyone from proposing promising alternatives for commercializing Alaska's North Slope reserves.

Introduction

I would like nothing better than to tell you today that commercial development of Alaska's North Slope reserves is at hand. However, I cannot do that. In reality, neither an overland pipeline to the lower 48 states nor the export of LNG to Far East markets is economic at today's prices. An assured market and a substantial real growth in energy prices will be required before a project to commercialize North Slope gas reserves can be economic. Exxon believes that such a market will develop in the lower 48 states which will

ultimately be the best market for North Slope gas. We further believe that an overland pipeline is the best mode of transportation to that market.

Exxon, like the State and its citizens, has a substantial interest in seeing these reserves commercialized. Exxon has approximately a 37 percent working interest in the gas reserves in the Prudhoe Bay Field and significant interests in Point Thomson and other nearby fields. Commercialization of these reserves would provide new job opportunities, further economic development and additional revenue for Alaska, as well as substantial income for Exxon.

Project Scope and Fundamentals

The Prudhoe Bay Field alone is estimated to contain 26 Tcf of gas.¹ There is also an estimated 8 Tcf of gas in Point Thomson and other nearby fields.² Any project to commercialize reserves of that magnitude would be a major, world-scale endeavor by any standards. Whether it is an overland pipeline to the lower 48 states or the export of LNG to Far East markets, it will be one of the largest privately financed projects in the free world.

The magnitude of the financial and business undertakings are as significant as the physical scope of the facilities. Large investments will be required -- \$10 billion or more -- and the lead times will be long -- 5 or more years of substantial investment -- before a single dollar of revenue will be received and many more years before any return on the investment can be realized. Numerous interests must be brought together, including the owners of the gas on the North Slope, the buyers of the gas, the pipeline owners, governments and financial institutions. Financing will require complex arrangements involving numerous entities and will only be possible if the project's economic basis is fundamentally sound.

Investors in a project of that magnitude will require stable supplies, dependable markets and a product which can be priced at a competitive level. In addition to these market fundamentals, a stable government fiscal and regulatory environment will be essential.

Alternatives Considered to Market North Slope Gas

Since the discovery of the Prudhoe Bay Field, Exxon has considered and reconsidered many alternative methods of commercializing Alaska North Slope gas reserves. These considerations have included overland pipelines to the lower 48 states and transportation of the gas to a tidewater port for liquefaction and shipment to domestic or foreign markets. Less conventional

¹ Alaska Department of Natural Resources, Historical And Projected Oil And Gas Consumption January 1989.

² Id.

alternatives, such as chemical conversion to methanol and locating petrochemical facilities at tidewater have also been studied. Based on our consideration of many alternatives, we have consistently concluded that the best market for North Slope gas will develop in the lower 48 states and that an overland pipeline will be the most economical and efficient method for delivering the most energy to that market.

At the time the present project for an overland pipeline was selected by the President and Congress, a competing project was also considered under which North Slope gas would be transported by pipeline to a tidewater port on the southern coast of Alaska and there liquified and shipped as LNG to California. That project was ultimately rejected because an overland pipeline could transport gas more efficiently and could be expanded at lower cost than an LNG project. Following selection of the Alaska Natural Gas Transportation System (ANGTS), Exxon participated as a member of the pipeline/producer consortium performing the design and engineering of the system. We remain active in that consortium to this day.

Overland Pipeline to Lower 48 States

Studies by the American Gas Association³ and Gas Research Institute⁴ have concluded that North Slope gas can be accommodated in the lower 48 states after the year 2000 and that energy prices will increase to a level which will make North Slope gas economic. These studies indicate that the Lower 48 demand will be sufficient to accommodate all domestic gas production, imports from other countries, as well as gas from the North Slope of Alaska. Our conclusions are generally consistent with those studies. We are optimistic that an overland pipeline to deliver the gas to the lower 48 states can be constructed in the time frame indicated by the studies.

In 1988, the pipeline sponsors of the ANGTS announced a 45 percent reduction in their prior cost estimate for the ANGTS. Given the improvements in pipeline design and construction techniques since their prior estimate, Exxon agrees that the cost of building the ANGTS can be significantly reduced as suggested by the ANGTS pipeline sponsors. Further reductions in cost that would enhance the economics of transporting the gas to the lower 48 states may also be possible.

An overland pipeline is a safe and efficient means of transporting energy over long distances. In addition, an overland pipeline can be expanded at relatively low cost if needed to accommodate new discoveries. Such expansion capability would encourage exploration for new gas reserves.

³ American Gas Association, The Gas Energy Supply Outlook, October 1987.

⁴ Gas Research Institute, 1987 GRI Baseline Projection Of U.S. Energy Supply And Demand To 2010, December 1987; 1988 GRI Baseline Projection Of U.S. Energy Supply And Demand (Preliminary) August 1988.

The use of North Slope gas in the lower 48 states will enhance U.S. energy security and ensure a stable long term supply of environmentally desirable fuel. Utilization of North Slope gas to meet U.S. energy needs can back out 400,000 to 600,000 barrels per day of imported oil.

Trans-Alaska Gas System

Lately, much attention has been focused on exports of North Slope gas as LNG to markets in the Far East. Governor Hickel and the team at Yukon Pacific are to be complimented for their efforts to develop the TAGS project. The TAGS project is a complex project consisting of integrated pipeline, liquefaction, shipping and regasification facilities. The 800-mile pipeline through Alaska would, in itself, be a project rivaling the Trans-Alaska oil pipeline. The LNG facility would be one of the world's largest and would require a substantial LNG ship fleet as well.

Exxon has considered the export of North Slope gas to the Far East and I must tell you that we have serious reservations that such a project would be competitive with other supplies in that market. Because of the substantial investment required to transport North Slope gas across Alaska, the LNG from such a project would be at a severe competitive disadvantage relative to other Far East and Middle East sources of LNG that would not be burdened by such a large pipeline investment. The supplies of LNG potentially available from these other sources vastly exceed any forecasts of demand for LNG in the Far East.

I have two charts that demonstrate this graphically. The first is a map which shows the potential supplies of LNG for Far East markets. The numbers shown under each country represent that country's gas reserves expressed in trillions of cubic feet. As shown, there is a lot of gas in the Far East and Middle East. The arrows from Alaska reflect the distances that North Slope LNG would be transported using tankers that are estimated to cost 2.4 billion dollars. The dashed line across Alaska represents the 5.4 billion dollar pipeline to Valdez, which, on an investment basis, is equivalent to adding 7,600 miles to the LNG shipping distance. Thus, North Slope gas is effectively 11,000 miles from Japan. 11,000 miles is roughly equal to one-half the circumference of the earth, therefore, all else being equal, LNG from almost anywhere in the world could be delivered more economically to the Far East than North Slope gas.

The table on my next chart puts shipping distances and potential supplies for the Far East into perspective. Shown are various countries arranged by their distance to Japan. Shown for each country are its estimated total proven reserves, the reserve which may be needed to meet current contracts assuming they are extended to the year 2020, and the remaining uncommitted reserves. As you can see, there are 1,127 trillion cubic feet of uncommitted reserves that are effectively closer to Japan than Prudhoe Bay. That volume is roughly 33 times the total known reserves on the North Slope. Assuming an export volume of 14 million tons of LNG per year, the suppliers closer to Far East markets than the North Slope could deliver that volume for over 1,400 years.

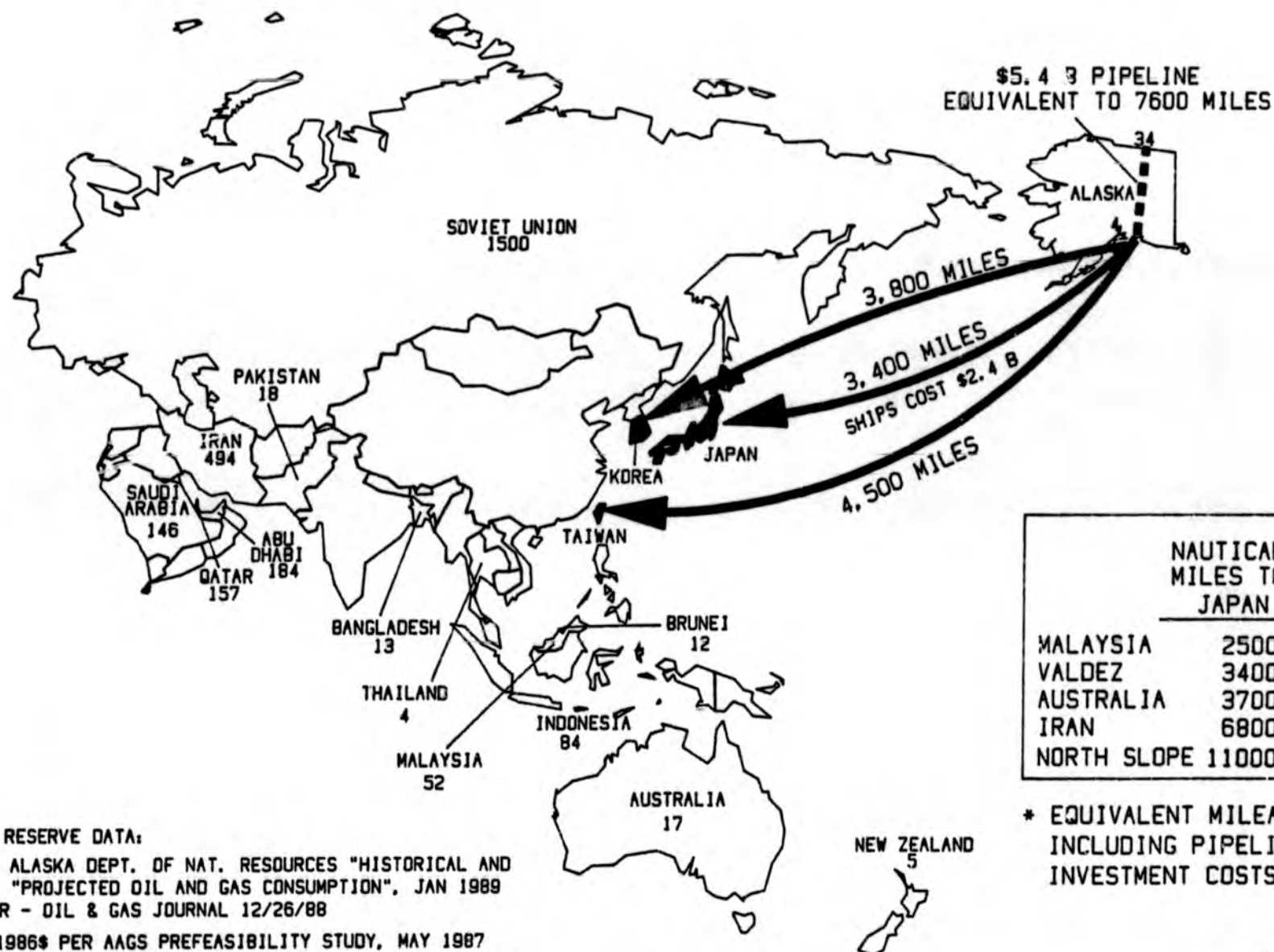
I would not want to be interpreted as suggesting that all of these reserves will be made available to Far East markets soon or even ever. However, it is clear that should Far East demand grow so that the full TAGS volume of 14 million tons of LNG per year could be accommodated, North Slope LNG would be the high cost supply in a potentially oversupplied market and thus, would not be competitive with other LNG supplies. (It should be noted that in Exxon's view, a smaller 7-8 million tons of LNG per year project would be grossly uneconomic.) It is also clear that there are ample supplies of gas in other countries that could be competitive in Far East markets.

Conclusion

Alaska's North Slope gas reserves are an important component of the energy future of both Exxon and the state of Alaska. On balance, Exxon continues to believe that an overland pipeline to the lower 48 states will be the best alternative for commercializing North Slope gas. In reaching this conclusion, numerous alternatives to bring these reserves to market have been studied. While Exxon has serious reservations about an LNG export project, we would not want to discourage anyone from proposing promising alternatives for commercializing the reserves. We will continue to examine options to market North Slope gas considering the market fundamentals against which any project must be tested.

POTENTIAL SUPPLIERS OF LNG TO FAR EAST MARKETS

XX = TCF OF RESERVES



NAUTICAL MILES TO JAPAN

MALAYSIA	2500
VALDEZ	3400
AUSTRALIA	3700
IRAN	6800
NORTH SLOPE	11000 *

* EQUIVALENT MILEAGE
INCLUDING PIPELINE
INVESTMENT COSTS.

SOURCE OF RESERVE DATA:

ALASKA - ALASKA DEPT. OF NAT. RESOURCES "HISTORICAL AND
"PROJECTED OIL AND GAS CONSUMPTION", JAN 1989

ALL OTHER - OIL & GAS JOURNAL 12/26/88

COSTS IN 1986\$ PER AAGS PREFEASIBILITY STUDY, MAY 1987
DISTANCES PER "WORLD-WIDE MARINE DISTANCE TABLES", 1976

LNGRES6

POTENTIAL SUPPLIERS OF LNG TO FAR EAST MARKETS

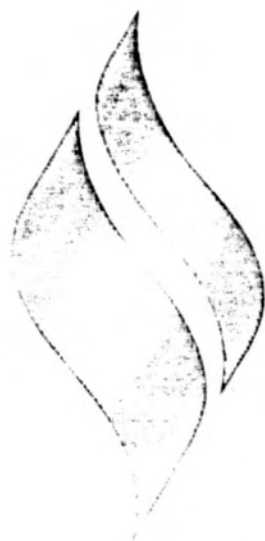
<u>COUNTRY</u>	<u>APPROXIMATE NAUTICAL MILES TO JAPAN</u>	<u>ESTIMATED PROVED RESERVES (TCF)</u>		
		<u>TOTAL</u>	<u>REQUIRED TO MEET EXISTING CONTRACTS IF EXTEND TO 2020</u>	<u>UNCOMMITTED</u>
Brunei	2400	12	9	3
Malaysia	2500	52	11	41
Indonesia	2900	84	26	58
Thailand	3000	4	-	4
U.S.-South Alaska	3400	4	2	2
Australia	3700	17	11	6
Bangladesh	4500	13	-	13
New Zealand	4800	5	-	5
Pakistan	5800	18	-	18
Abu Dhabi	6300	184	4	180
Qatar	6500	157	-	157
Saudi Arabia	6600	146	-	146
Iran	6800	494	-	494
Reserves effectively closer than North Slope:		1190	63	1127

33 TIMES THE KNOWN NORTH SLOPE
GAS RESERVES. EQUIVALENT TO
14 MT OF LNG (.8 Tcf) PER YEAR
FOR OVER 1,400 YEARS.

SOURCE OF TOTAL RESERVES DATA:

- South Alaska & North Slope - Alaska Department of Natural Resources publication entitled "Historical and Projected Oil and Gas Consumption" published January 1989.
- All others - Oil & Gas Journal 12/26/88

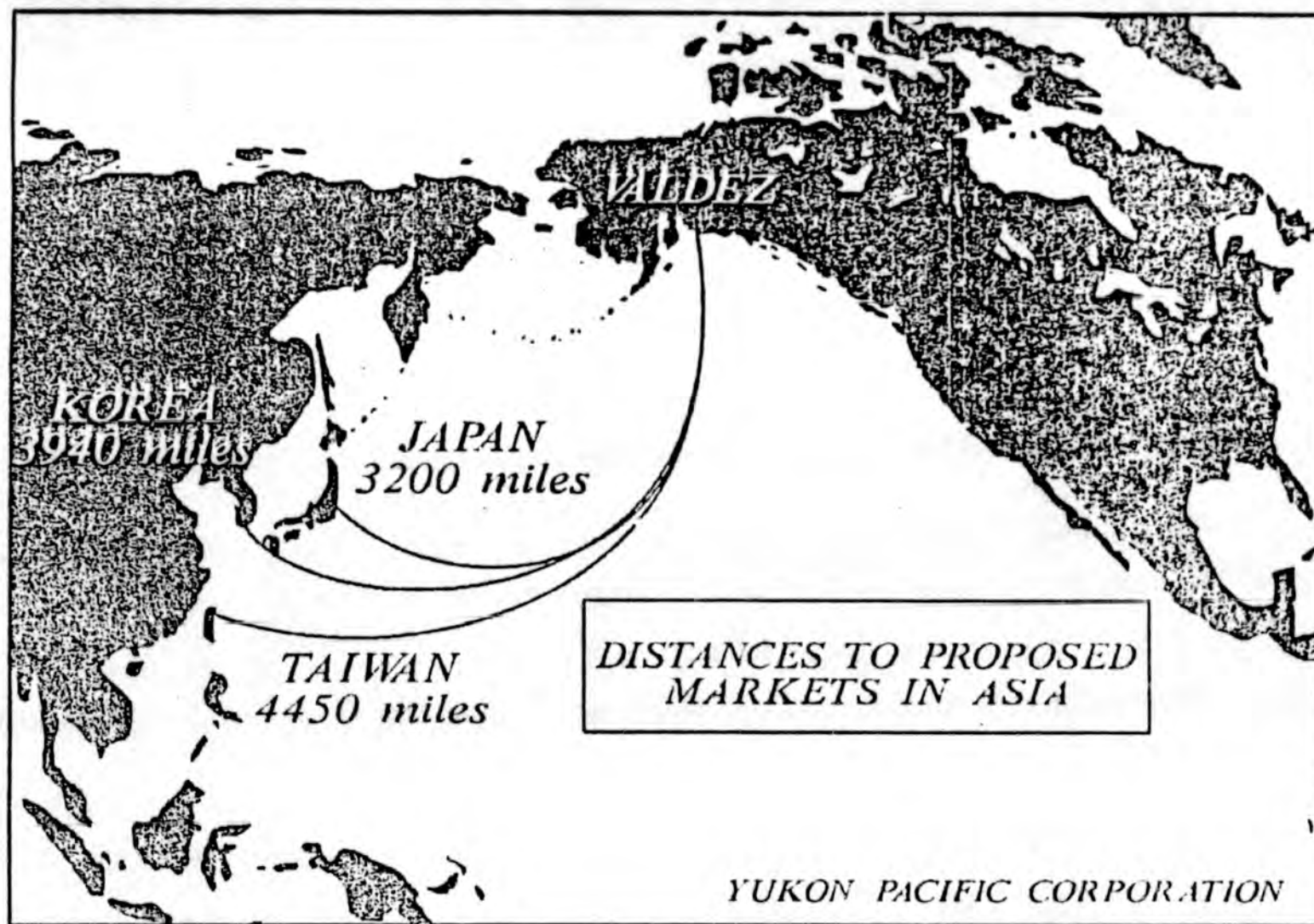
DISTANCES PER "WORLD-WIDE MARINE DISTANCE TABLES", 1976



**YUKON
PACIFIC
CORPORATION**
TRANS ALASKA GAS SYSTEM

CSX Corporation

- Majority owner of Yukon Pacific
- Major transportation company
- 1987 turnover:
\$8 billion on \$13.2 billion in assets



Phase I TAGS Permits

1. Define F.E.R.C. role ☐
2. Obtain Federal Right-of-Way
(requires Environmental Impact Statement) ☐
3. Obtain Presidential Finding
(required under ANGTA) ☐
4. Obtain State Right-of-Way ☐
5. Obtain Federal Export License ☐

Phase I TAGS Permits

1. Define F.E.R.C. role ☒
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3. Obtain Presidential Finding
(required under ANGTA) ☒
4. Obtain State Right-of-Way ☒
5. Obtain Federal Export License ☐

* Application pending, awaiting decision

YUKON PACIFIC CORPORATION TASKS

PHASE II

- o Detailed Design
- o Detailed Permitting
- o Final Cost Estimate
- o Final Contracts

Asian LNG Demand by 2000

(million tons)

	<u>Currently under Contract</u>	<u>Projected by 2000</u>		<u>Total New Demand</u>	
		1987	1989	1987	1989
Japan	34.0	38.0	48.0	4.0	14.0
Korea	2.0	3.5	8.7	1.5	6.7
Taiwan	<u>1.5</u>	<u>3.0</u>	<u>4.5</u>	<u>1.5</u>	<u>3.0</u>
TOTAL	37.5	44.5	61.2	7.0	23.7

Source: Government and Research Institute Projections in each country

Reasons for LNG Demand Growth in Asia

- Greater electricity demand than expected
- LNG more competitive, especially vs. nuclear
- Rising environmental concerns
- Diversification to reduce energy source risk
- Distribution infrastructure is growing

Alaska LNG is Competitive in Asia

- Price competitive
- Economies of scale
- U.S. a secure supplier
- Expand U.S. trade where most needed

Capital Cost Estimates

(\$ millions)

	<u>To Deliver 7MMT/YR</u>	<u>To Raise to 14MMT/YR</u>	<u>TOTAL</u>
Alaska facilities	6,816	1,824	8,640
Shipping	<u>980</u>	<u>1,120</u>	<u>2,100</u>
Total	\$7,796	\$2,944	\$10,740

Economic Feasibility

- Sales threshold of 7-8.5 mmt in mid-1990's.
- Economic studies based on \$24/bbl crude oil and LNG price of \$4/mmbtu.
- Price will fluctuate up and down with crude oil.
- Alaska does not have a posted crude oil price.

TAGS Gas Supply

North Slope Gas Reserves	36 TCF
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Undiscovered Resources	102 TCF
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Gas Ownership:

ARCO, EXXON, British Petroleum,
State of Alaska and minor owners

"Undiscovered, recoverable supplies of natural gas from Alaska's North Slope may exceed 100 trillion cubic feet."

Presidential Finding Excerpt
Yukon Pacific Corporation
Exhibit "M"

STATE INCENTIVES TO MOVE FORWARD

- Tax, Royalty Income of \$1-2 million/day.
- 10,000 Construction jobs.
- 550 Permanent jobs.
- Spur to other exploration, refining
- Alaska's largest opportunity

What can the State do to help?

- Continue International Trade Office efforts. Customers and competitors are governments; it helps for our government to lend support.
- Continue cooperative efforts in right-of-way and environmental permitting.
- Maintain stable tax climate.
- Enter into royalty gas sales discussions when appropriate.



BP EXPLORATION

B.E. Grote
Vice President
Commercial, Alaska

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 564-5121

BP EXPLORATION POSITION REGARDING NORTH SLOPE NATURAL GAS

- BP Exploration is the owner of approximately 25% of the 26 trillion cubic feet of gas at Prudhoe Bay.
- We are determined to see the gas developed as soon as possible and have continuously sought out alternatives for moving the gas to market.
 - We have been a member of the ANGTS Design and Engineering Cooperative Agreement since 1980.
 - We have evaluated a wide range of options, including TAGS, since the initial delay of ANGTS announced in 1982.
- In March, 1984, we spoke before the Alaska State Legislature Joint Committee on Oil and Gas indicating our support of ANGTS as the most likely means of getting gas to market.
- While BP Exploration continues as an ANGTS participant, we now believe that the progress made by Yukon Pacific warrants full consideration.
- E.J.P. Browne, Chief Executive, BP Exploration, U.S.A., stated in February that BP is willing to work with Yukon Pacific to determine if the TAGS project is possible and would be prepared, under the right circumstances, to commit our gas to the project.
- Both ANGTS and TAGS face a number of major hurdles -- most serious of which are the uncertainties of future energy prices and the sheer scale of both projects.
- In the absence of a gas pipeline, we still strive to get maximum benefit from the gas being produced -- as fuel for field production facilities and the Trans-Alaska Pipeline, as a component of miscible injectant for enhanced oil recovery, and finally by reinjecting the remainder to maintain reservoir pressure.
- The State of Alaska can help progress North Slope gas development by working to prevent the creation of any barriers that would restrict the range of options available for consideration.

March 10, 1989



ALASKA SEGMENT

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

Alaskan Northwest Natural Gas
Transportation Company

YUKON PACIFIC CORPORATION
(ERA DOCKET NO. 87-68-LNG)

CUBA WADLINGTON JR
VICE PRESIDENT
NORTHWEST ALASKAN PIPELINE CO.

JANUARY 24, 1989

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

PREPARED STATEMENT OF
CUBA WADLINGTON JR., VICE PRESIDENT FOR REGULATORY AFFAIRS
NORTHWEST ALASKAN PIPELINE COMPANY

AT PUBLIC CONFERENCE, JANUARY 24, 1989
ANCHORAGE, ALASKA
ERA DOCKET NO. 87-68-LNG (YUKON PACIFIC CORPORATION)

I. INTRODUCTION

I am Cuba Wadlington Jr., Vice President for Regulatory Affairs, Northwest Alaskan Pipeline Company, the agent and operating partner for Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest"), the sponsors of the Alaskan segment of the Alaska Natural Gas Transportation System ("ANGTS").

The delivered gas price in the lower-48 states is a critical determinant of the feasibility and timing of an overland pipeline system from Alaska. I will explain why we are confident that the Prudhoe Bay gas will be salable to American consumers on a free-market basis, without government subsidy, and squarely within the Yukon Pacific Corporation's ("Yukon Pacific") supposed period of export (i.e., 1996-2021).

II. THE DOMESTIC MARKET FOR NATURAL GAS

I will first review the prices projected for pipeline imports and liquefied natural gas ("LNG") so that we have a basis for determining whether the ANGTS gas reasonably could be competitive with these potential alternatives. All prices are at the U.S. lower-48 border.

The "acquisition prices" of pipeline imports and LNG have been projected to 2010 by the Gas Research Institute ("GRI"), a highly respected analytical organization whose forecasts are widely used in industry and government.

GRI's Acquisition Prices of Natural Gas ^{1/} (1987 Dollars/ million Btu)

	1987	1988	1990	1995	2000	2005	2010
Pipeline Imports	2.14	2.16	2.67	3.20	3.86	5.08	6.37
LNG	3.04	2.96	2.83	3.20	4.10	5.46	6.80

From these data, a rising trend in real prices is clearly evident, and LNG imports generally are more expensive than pipeline imports. It is important to note that GRI forecasts an increasing total domestic demand for natural gas through 2010 despite this increase in real prices. With these figures as a background for comparison purposes, I will address the price and marketability of Alaskan gas as delivered by pipeline through

^{1/} Gas Research Institute, Baseline Projection Data Book; 1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010, Washington, D.C., released Fall 1988, p. 344. "Acquisition price," as defined by GRI, is the weighted average price for each of the supply sources at the point of entry into the U.S. pipeline transportation system. To facilitate comparison with the projected ANGTS prices, the GRI figure of 3.20 for 1995 converts to \$3.32 for 1996 (a 3.82% escalation, specified by GRI).

Canada to the U.S. border.

Before doing so, I would observe that expert gas market analysts reasonably might differ over any particular forecast of gas prices, which necessarily are based on assumptions regarding future economic growth, world oil prices, etc.

Of overriding importance, however, is the fact that there is a consensus among qualified observers that the real price of both lower-48 gas production and imports will rise over the years ahead. Only the rate of increase may differ. ^{2/} This fact, as I will demonstrate, virtually assures the domestic marketability of Alaskan pipeline gas and leaves open only the question of specific timing.

III. MARKETABILITY OF ALASKAN PIPELINE GAS

A. The Levelized Cost of Service Concept

Salability of Alaskan pipeline gas domestically will be determined primarily by: (1) capital costs of the pipeline system and (2) the wellhead price of the gas. Within reasonable limits, steps can be taken to facilitate and perhaps accelerate marketability by introducing flexibility in cost recovery. To do so, we plan to modify, i.e., "levelize," the traditional cost

^{2/} See, for example, Energy Information Administration ("EIA"), U.S. Department of Energy, Annual Energy Outlook 1987 With Projections to 2000, October 1987, pages 28, 35, 40. EIA, on page 28 also presents forecasts by Data Resources, Inc. and the Wharton Econometric Forecasting Associates. See also Washington Policy and Analysis, Natural Gas: A Strategic Resource for the Future, November 28, 1988, p. 16.

recovery pattern which starts high and steeply declines as facilities are depreciated. Levelization is accomplished by deferring the recovery of certain costs to later years. Since the levelized approach starts with a much lower rate, salability of the Alaskan gas at market clearing prices can be assured. We have long planned to implement this concept, which was first elaborated upon publicly in our testimony before the Congress in November 1983. ^{3/}

The levelization concept consists of two elements. First, some part of the wellhead price is deferred in the early years to be made-up with payments in later years. The gas producers obviously will want to be satisfied that they can obtain a satisfactory return over the life of the project. Second, transportation cost recovery is reduced in the early years by partially deferring depreciation and by capitalizing return on equity. These two elements can be combined in varying degrees to achieve a target price, i.e., the market clearing price for natural gas.

B. Revised Capital Cost Estimate for the ANGTS

In May 1988, the Canadian and U.S. sponsors of the ANGTS completed an important reestimate of the capital cost of the remaining elements of the ANGTS. The study drew upon an extensive body of proprietary and confidential information

^{3/} See Testimony of Vernon T. Jones, before the Subcommittee on Energy Regulation of the Energy and National Resources Committee, U.S., Senate, November 16, 1983, prepared statement, pages 37-40.

developed since the earlier cost estimate prepared in the late 1970s and early 1980s. It took into consideration:

- advances in pipeline design,
- information gathered from extensive field testing programs and optimization studies conducted by the project sponsors, and
- significant changes in the economic climate.

The result was a dramatically lower cost estimate, resulting in part from the following:

- reduced construction schedule,
- improved welding technology,
- more traditional owner/contractor functions,
- use of existing communication systems,
- reduced contingency,
- higher pressure, smaller diameter mainline pipe, but higher gas throughput, and
- more modest rate of inflation and steady interest rates.

Expressed in January 1, 1988 dollars, the capital cost of the project, including the North Slope conditioning plant together with the remaining pipeline segments in Alaska, Canada and the lower-48 states, was estimated at \$14.6 billion, compared to \$26.1 billion in the earlier estimate--a 45% reduction. This, in turn resulted in a new cost of the pipeline delivery service.

C. Revised Cost of Service for the ANGTS

Based on the new capital cost estimate, a traditional, initial cost of service of \$3.90 per million Btu in 1987 dollars

for a 1996 in-service date first was derived. ^{4/} We then structured a levelized cost of service in which the initial cost commences at a substantially lower rate and remains level in real dollars for a number of years. Although the levelized cost figure that we determined appears reasonable as an example, the actual scheduling of costs to be deferred would be the subject of negotiations between all parties concerned, including regulatory authorities. The levelized figure that we arrived at is \$2.44 per million Btu at the lower-48 border, which does not include recovery of the gas price.

I will now compare the ANGTS levelized transportation cost of service for a 1996 in-service date to the projected border prices of pipeline imports and LNG for the same year, which will indicate how much latitude there is for wellhead price recovery in the initial year of operation.

Cost Comparison-Year 1996
(1987 dollars, million Btu)

Pipeline Imports & LNG	\$3.32
ANGTS Transportation	
Levelized Cost of Service	<u>-2.44</u>
Amount available for	\$0.88
Initial Gas Price	
Netback	

^{4/} See Northwest Alaskan Pipeline Company, New Transportation Economics for Alaskan Gas, June 1988. (Copy attached as Exhibit A.) The cost of service prices specified therein, expressed in January 1, 1988 dollars, have been converted to 1987 dollars for use in this testimony to facilitate comparisons. Further, the ANGTS cost of service is specified at the border between Canada and the lower-48 in this testimony which also will facilitate comparisons. All cost of service figures include recovery of financing costs, including interest and an allowance for equity funds used during construction.

The \$3.32 figure is GRI's projected price, adjusted to 1996 (see f.n. 1 supra). By subtracting the \$2.44 ANGTS levelized transportation cost from \$3.32, as shown, the difference of \$0.88 would be available to commence recovery of the ANGTS wellhead price. It must be kept in mind, of course, that the levelization concept allows for full recovery of both the wellhead price and all transportation costs in subsequent years.

Up till now, I've used a 1996 initial in-service date as an example. The ANGTS gas would be competitive at that time based on the projected prices; however, the specific date that the Alaskan gas will flow will be determined by actual developments in the market place. In this regard, several key factors will make the ANGTS gas much more salable--even without a levelized cost of service--as time goes on. They are:

- the capital costs of the "prebuilt," operating portions of the system (about 1/3 of the total mileage) continue to be depreciated, thus resulting in a progressively lower transportation cost of service.
- the real cost of gas imports, LNG, and other alternatives is projected by most observers to rise substantially over time, as I've previously documented. On the other hand, both the Prudhoe Bay gas price and the pipeline construction costs should remain essentially level in real dollar terms. The Prudhoe Bay gas, it should be noted, will incur virtually no additional production or gathering costs. The net effect is to make Alaskan pipeline gas progressively more attractive than potential alternatives

in the years ahead.

We have previously placed in the record the reestimated ANGTS costs in comparison with the figures for the potential alternatives presented in the study done for Yukon Pacific by Dames & Moore and Decision Focus, Inc. ("D & M Report"). ^{5/} It is crystal clear from that comparison that Alaskan pipeline gas will achieve a substantial, increasing price advantage during the period 1997 through 2017. By 2007, the ANGTS gas will be 37% less expensive than Mexican imports, 36% less than LNG imports, and 8% less than Canadian imports. By 2017 the ANGTS advantage widens considerably, and its delivered cost then will be less than even the wellhead price of most domestically produced gas.

D. Marketing Concept for Alaskan Pipeline Gas

The ANGTS sponsors recognize clearly the radically altered domestic gas market today as compared to the late 1970s when the Alaska gas pipeline project was initiated. At that time, a handfull of major interstate gas transmission companies planned to purchase the Prudhoe Bay gas for resale from their own inventory. Today, with the emphasis on open access to transportation services and competition among suppliers, a new approach is required. In short, the major end users of the gas, i.e., local distribution companies ("LDCs"), certain electric

^{5/} See Alaskan Northwest's Reply Comments to the ERA, Docket 87-68-ING, September 23, 1988, pages 29-31. The D & M Report is in Yukon Pacific's Initial Comments of August 24, 1988, Exhibit R, Table 6-7 on page 6-30.

utility systems, and possibly major industrial users need to be key elements in bringing the Alaskan gas to market.

We have noted previously that the long-term, assured source of supply represented by the Prudhoe Bay gas is highly attractive. These attributes will be particularly important as gas increasingly becomes the fuel of choice for major electric generating plants. The successful financing of major combined cycle and combustion turbine gas plants requires assurance of gas supply and reasonably predictable prices. Gas supply contracts of 15 years or more typically are demanded, but currently are not always available.

As the gas "bubble" dissipates over the next two years, as most responsible observers predict, ^{6/} the spot market for gas purchases is likely to become more unpredictable and, therefore, less attractive. Under these circumstances, we foresee a renewed receptiveness to long-term supply arrangements.

Our concept is that, at the appropriate time, we will establish a group of, say, 30-40 selected LDCs, utilities, and possibly major industrial users who will provide letters of intent to purchase the gas and some degree of financial participation in the project. An expanded group of transmission companies would also be included, along with the North Slope producers.

With such an expanded group, the individual risk and the financial contribution from each participant would be lessened

^{6/} See, for example, EIA, Annual Energy Outlook 1987, p. 13.

considerably in contrast to the approach of the 1970s.

IV. SUMMARY-CONCLUSION

Alaskan pipeline gas, based on reasonable price projections for potential alternatives (e.g., pipeline imports, LNG), should be very salable in the domestic market during Yukon Pacific's proposed period of export. The delivered gas will be increasingly competitive each year that passes from 1996 forward into the next century as the real prices of alternatives continue to rise.

The sponsors expect to use a levelized cost of service to recover costs which will help ensure sale of the gas at market clearing prices.

Establishment of a new grouping of major gas users together with the transmission companies and the producers will be explored as a means of facilitating project remobilization.

Finally, since the gas reasonably will be salable domestically on a free-market basis, it is indisputable that American consumers will have to pay higher prices or make use of less desirable energy sources if Alaskan pipeline gas is not available.

THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM

**NEW
TRANSPORTATION
ECONOMICS
FOR
ALASKAN GAS**



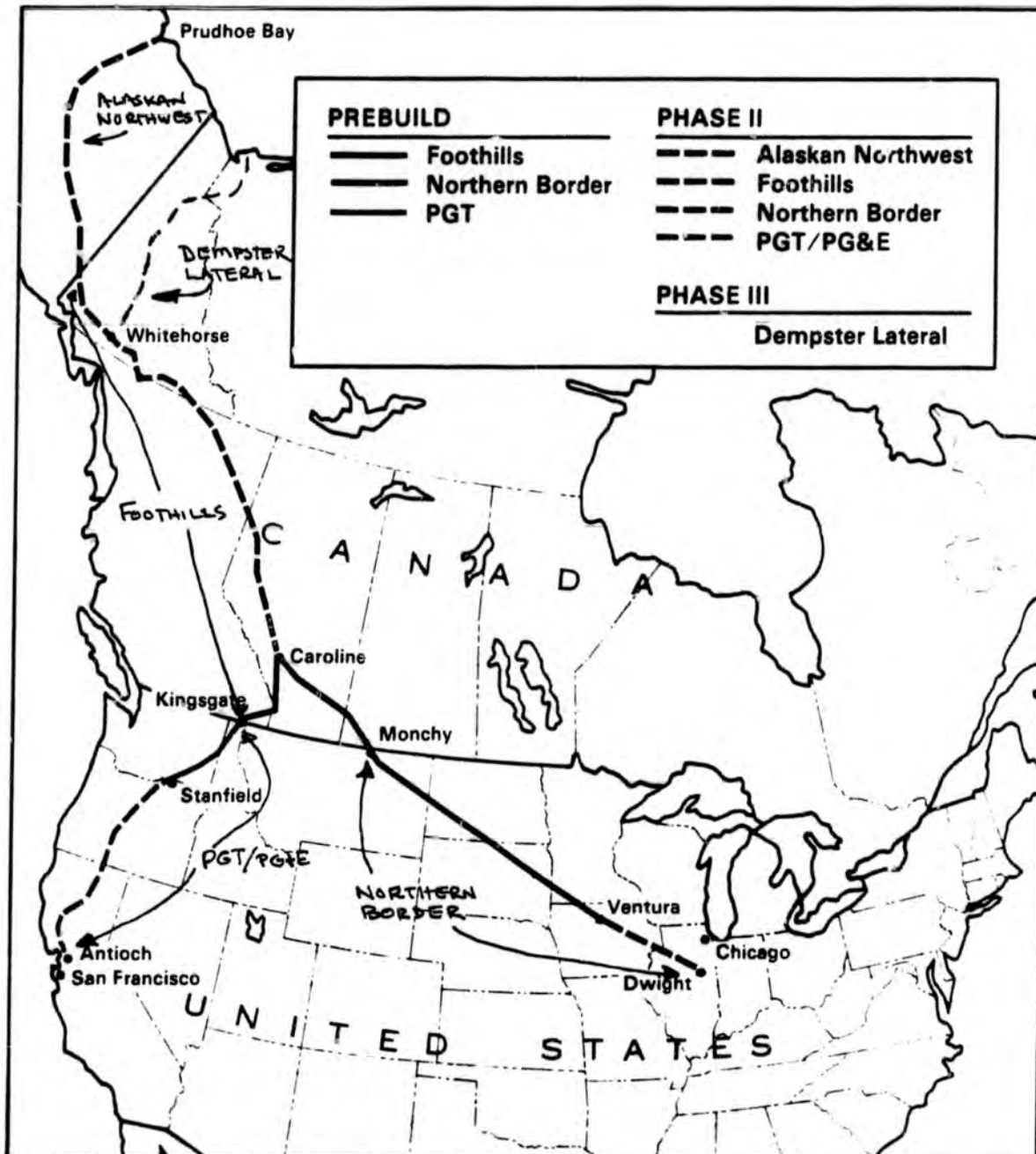
NORTHWEST ALASKAN PIPELINE COMPANY

**Operator For
Alaskan Northwest Natural Gas Transportation Company**

JUNE 1988

Exhibit A

THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM



THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM

OVERVIEW

- Alaskan Northwest Natural Gas Transportation Company (ANNGTC) is the U.S. sponsor for the Alaskan segment of the Alaska Natural Gas Transportation System (ANGTS), and Foothills Pipe Lines (Yukon) Ltd. is the Canadian sponsor of ANGTS, a project selected in both the United States and Canada as the most effective and environmentally sound means to deliver Alaskan gas reserves to the lower 48 United States. The ANGTS is the subject of a bilateral agreement between the United States and Canada and legislation in both countries which provides for the expeditious approval and construction of the project.
- In the early 1980's, the Phase I or Prebuild portion of the ANGTS was constructed and placed into operation for the delivery of Canadian gas in advance of the transportation of Alaskan natural gas. This represents completion of approximately one-third of the ANGTS.
- The project sponsors remain committed to the timely construction of the northern or Phase II portions of the system. The securing of governmental/regulatory approvals to date in combination with the completion of a substantial portion of project engineering design and the technical knowledge acquired from pre-construction field studies will enable the ANGTS sponsors to construct the remaining portion of the project in the most expeditious time frame possible.
- In early 1987 ANNGTC and Foothills decided to conduct a reassessment of project design, capital cost estimates and related cost of service. The re-estimate has resulted in significant reductions in the cost of transporting Alaskan gas to lower 48 markets. These lower costs incorporate advances in pipeline design and information gathered from extensive field testing programs conducted by the project sponsors as well as the significant changes in the economic climate from earlier estimates.
- The information concerning the capital cost re-estimate and cost of service provided in the remainder of this document indicates why the project sponsors believe that the ANGTS will be completed in accordance with the Agreement on Principles between the United States and Canada.

THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM
**COMPARISON OF CAPITAL COSTS FOR PRUDHOE BAY
 GAS**
 (BILLIONS OF \$'s)

	<u>1982 \$</u>	<u>January 1, 1988 \$</u>	
	<u>1982</u>	<u>1982</u>	<u>1988</u>
ALASKAN SEGMENT	\$14.2	\$15.6	\$ 7.2
CANADIAN SEGMENT	7.9	8.2	5.6
LOWER 48 STATES	<u>2.1</u>	<u>2.3</u>	<u>1.8</u>
TOTAL	<u>\$24.2</u>	<u>\$26.1</u>	<u>\$14.6</u>

% Reduction from 1982 estimate (expressed in 1988 dollars)	45%
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THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM

1982 VERSUS 1988 ASSUMPTIONS

GENERAL	1982 BASELINE ESTIMATE	1988 RE-DESIGN ESTIMATE
Flow	2100 MMCFD	2300 MMCFD
Pipe diameter	48" 56"	42"/48"
Pressure	1260 /1080 psig	2160 /1680 psig
Mainline provision for future Delta flow	Yes	Yes
Economic forecast	High interest and inflation rates beyond 1982	More modest rate of inflation and steady interest rates

KEY FACTORS CONTRIBUTING TO REDUCTION IN CAPITAL COSTS ESTIMATE

(1988 ESTIMATE FROM 1982 ESTIMATE)

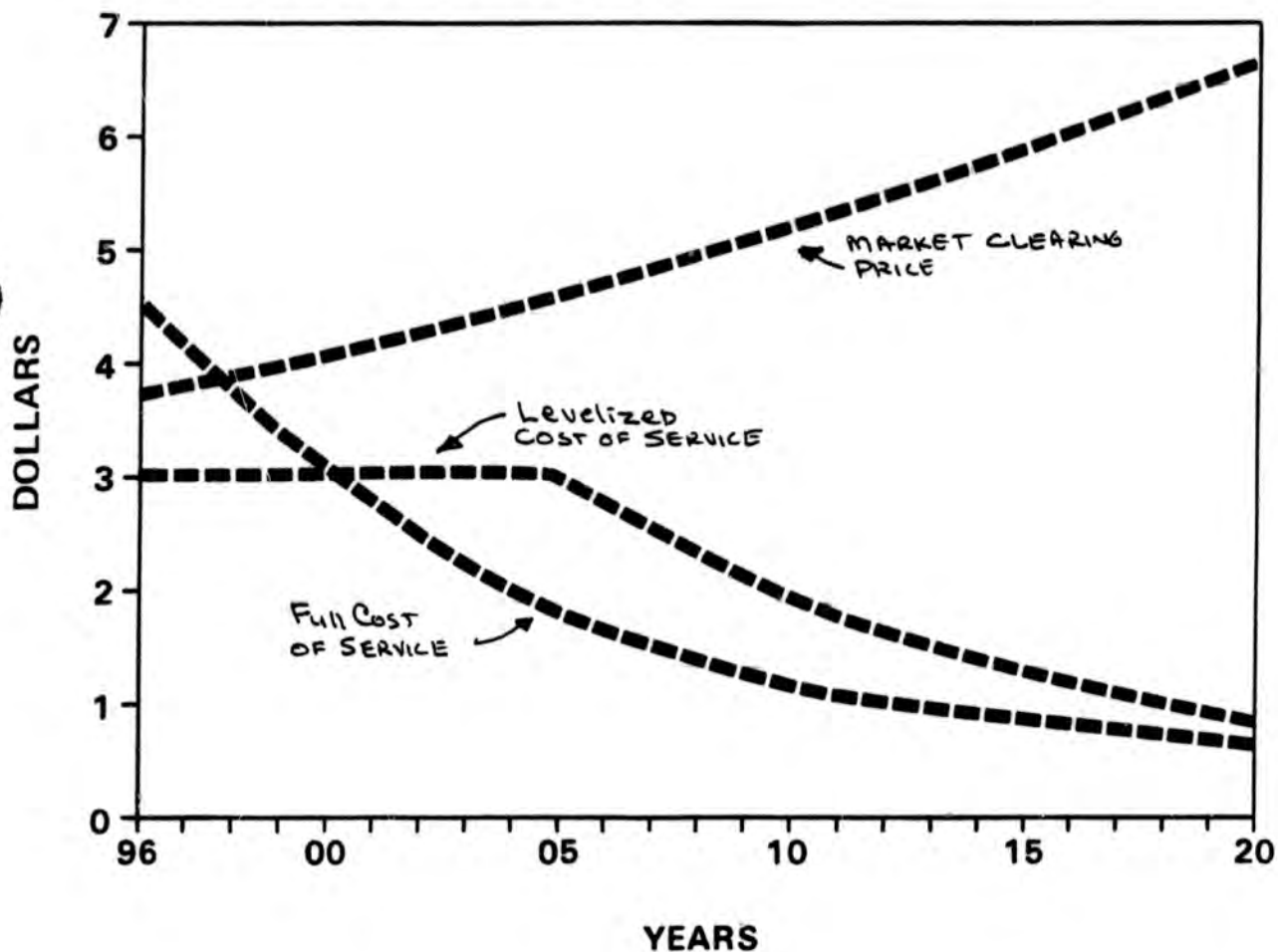
- Reduced construction schedule.
- Incorporation of results from project test sites.
- Advancements in pipeline design.
- Improved welding productivity.
- More traditional owner/contractor functions.
- Use of existing communication systems.
- Reduced contingency.

THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM
COMPARISON OF COST OF SERVICE
1988 \$/MMBTU - PRUDHOE TO LOWER 48

	<u>1996 In-Service</u>	
	<u>Full Cost</u>	<u>Levelized Cost</u>
ALASKAN SEGMENT	\$2.33	\$1.48
CANADIAN SEGMENT	1.76	1.06
LOWER 48 STATES	<u>.51</u>	<u>.51</u>
TOTAL COST OF SERVICE TO LOWER 48 STATES	<u>\$4.60</u>	<u>\$3.05</u>

THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM
COMPARISON OF COST OF SERVICE
1988 \$/MMBTU - PRUDHOE TO LOWER 48

- Market Clearing Price, 2.5% Real Growth - MMBtu
- Full Cost of Service
- Levelized Cost of Service





NORTHWEST ALASKAN PIPELINE COMPANY

**Operator For
Alaskan Northwest Natural Gas Transportation Company**

**295 Chipeta Way
Salt Lake City, UT 84108-1281**

THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM
PROGRESS TO DATE — ACCOMPLISHMENTS

- Alaska Natural Gas Transportation Act of 1976 enacted by Congress and signed by the President.
- Agreement on Principles between the United States and Canada applicable to the ANGTS was executed in September, 1977 for a minimum term of 35 years.
- ANGTS approved by Presidential decision and ratified by Congress in 1977.
- Certificates of public convenience and necessity granted to Foothills and conditional certificates to ANNGTC following public hearings before the National Energy Board in Canada and the Federal Power Commission in the United States.
- Northern Pipeline Act enacted by the Canadian Parliament in April, 1978 formally granting Canadian certificates to Foothills.
- Thirty-year federal right-of-way for Alaskan segment granted in 1980.
- Congressional waiver of U.S. laws in 1981 to assist project financing.
- In 1981 and 1982, respectively, the Western and Eastern Legs of Phase I of the ANGTS were completed.
- In 1983, Foothills granted a right-of-way in Yukon by easement agreement with the Government of Canada for a period of 25 years with an option to renew for 24 additional years. Easement conditional upon receipt of ministerial consent to commence initial construction, recently extended to November, 1992.
- A substantial portion of major pipeline engineering design has been completed.



ALASKA NATURAL GAS TRANSPORTATION BY PIPELINE

Alaska Northwest Natural Gas
Transportation Company

YUKON PACIFIC CORPORATION
(ERA DOCKET NO. 87-68-LNG)

SUPPLEMENTAL COMMENTS RELATING TO
JANUARY 24, 1989 CONFERENCE

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

YUKON PACIFIC CORPORATION

ERA DOCKET NO. 87-68-LNG

SUPPLEMENTAL COMMENTS RELATING TO
JANUARY 24, 1989 CONFERENCE

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Dated: February 7, 1989

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Exhibit A	Energy Information Adminis- tration, <u>U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1987 Annual Report, October 1988</u>
Exhibit B	Alaska Oil and Gas Conservation Commission, <u>Bulletin, "Estimate of Gas Reserves in Alaska," May 1988</u>
Exhibit C	Alaska Department of Natural Resources, <u>Historical and Projected Oil and Gas Consumption, January 1989</u>
Exhibit D	Gas Research Institute, <u>1988 Baseline Projection of U.S. Energy Supply and Demand to 2010 (Draft 1/10/89), December 1988</u>

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 <u>Statutes</u>	
<u>Alaska Natural Gas Transportation Act</u> , 15 U.S.C. §§719 <u>et seq.</u>	passim
<u>National Environmental Policy Act</u> , 42 U.S.C. §§4231 <u>et seq.</u>	passim
<u>Natural Gas Act</u> , 15 U.S.C. §§ 717 <u>et seq.</u>	passim



Waiver of Law, S.J. Res. 115, Pub. L. No.
97-93 97th Cong. 1st Sess. (1981).

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I. OVERVIEW

At the January 24, 1989 public conference in Anchorage, Alaska, representatives of the Economic Regulatory Administration ("ERA") of the Department of Energy requested that the parties file certain information. ^{1/} Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest") reasserts its firm conviction that the insufficient record adduced to date compels denial of the Application. Nevertheless, in compliance with ERA's request, the following is herein submitted:

- The factual and legal basis for conditions to be attached to any export authorization that might be issued to Yukon Pacific Corporation ("Yukon Pacific"), together with specific proposed language.

- summary of the issue regarding North Slope gas conditioning facilities for the Alaska Natural Gas Transportation System ("ANGTS") and for Yukon Pacific's proposed export project, including Alaskan Northwest's position.

^{1/} See Tr. 101, 180, 204-205, 219.

II. FACTUAL BASIS FOR IMPOSITION OF PROPOSED CONDITIONS

A. Proved North Slope Gas Reserves Are Inadequate For Two Projects

Alaskan Northwest herein supplements its prior treatment of the issue of whether there exists sufficient proven reserves to support both the Trans-Alaska Gas System ("TAGS") and the ANGTS, ^{2/} and provides recent evidence from State and Federal Government sources to demonstrate that the projects are mutually exclusive as to reserves. ^{3/} The evidence demonstrates conclusively that some 26 trillion cubic feet ("tcf") of proved gas reserves are available for only one major gas transportation system in the same time frame.

Proof of an adequate, well-defined, gas reserve base is an essential prerequisite to obtaining regulatory approval--and the subsequent financing--of construction and operation of a pipeline

^{2/} See the following previously submitted Alaskan Northwest testimony: Motion of March 9, 1988, pp. 47-51, 54-56; (2) Comments, August 24, 1989, p. 9 and Exhibit A; (3) Reply Comments, September 23, 1989, p. 31 and Exhibit G, p. 10-11; (4) Prepared Statement of Vernon T. Jones, January 24, 1989 (pp. 11-13); and (5) Prepared Statement of James T. Jensen, January 24, 1989.

^{3/} There are only three government agencies (one Federal and two State of Alaska) that independently make annual estimates of proved reserves of natural gas in Alaska. The current estimate of each of them is discussed herein. The Bureau of Land Management ("BLM"), cited by Yukon Pacific on January 24, does not produce its own reserve estimates; in Economics of Oil and Gas Production from ANWR for the Determination of Minimum Economic Field Size, by John B. Young and William S. Hauser, BLM, 1968, p. 4, a brief historical reference is made to quantities of "recoverable resources" in the Prudhoe Bay Field, but no reference source is cited.

system. This was an important part of the Federal Energy Regulatory Commission's ("FERC") formal review in 1975 and 1976 of the then three proposed pipeline systems to transport the Prudhoe Bay gas. Detailed analyses and testimony were required from qualified reservoir engineers and other expert witnesses to substantiate the gas reserve base. Subsequently, in the early 1980s, the financial institutions that were considering financing the ANGTS also performed their own, independent analysis using an expert consulting firm to obtain assurance that at least 26 tcf of proved, economically transportable reserves ^{4/} were available at Prudhoe Bay. The key concerns were the magnitude of the proved reserves, the assurance of sustained deliverability for the twenty-five year economic life of the project, and the degree of confidence in the cost of production. Current government forecasts of proved reserves are discussed below:

1. Federal Government Estimate

The Energy Information Administration of the U.S. Department of Energy ("EIA") currently is the only source of nationwide, comprehensive, authoritative proved reserve estimates. Its annual report is the "bible" with respect to U.S. proved reserves, and its most recent edition (as of December 31, 1987) specifies 24.6 tcf of proved reserves of dry natural gas on the

^{4/} Any resource category other than "proved reserves"--such as "undiscovered reserves" or "potential recoverable resources," as cited by Yukon Pacific, Tr. Exhibit I, will not be relied upon by lenders financing a project such as TAGS or ANGTS.

North Slope. 5/

2. Alaska Oil and Gas Conservation Commission ("AOGCC") Estimate

The AOGCC annually publishes its list of proved reserves within the state. Its most recent report (as of January 1, 1988) indicates the following proved, salable North Slope gas reserves for the fields/reservoirs indicated:

<u>AOGCC Estimate of</u> <u>North Slope Proved Reserves</u> <u>6/</u> (Billions of standard cubic feet, dry)	
Endicott	798
Kuparuk	634
Prudhoe Bay (Lisburne)	406
Prudhoe Bay (Oil Pool)	<u>20,628</u>
	22,466

All of the fields indicated above are in relatively close proximity to the general Prudhoe Bay complex, and all are connected to the central gas facility. The AOGCC report names

5/ See EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1987 Annual Report (DOE/EIA-0216 (87)), Released October 27, 1988 (Copies of relevant pages attached as Exhibit A.)

6/ See AOGCC, Bulletin, "Estimate of Gas Reserves in Alaska," May 1988, p. 4. Based on a telephone conversation with Mr. Russell Douglas of AOGCC on January 27, 1989, the AOGCC figures were adjusted by subtracting 12% carbon dioxide for the Endicott Field as well as the Prudhoe Bay (Oil Pool) fields in order to obtain true "dry gas" figures comparable to other sources. The figures, as adjusted, shown above include all quantities listed that are on the North Slope except 15 billion cubic feet ("bcf") of proved reserves in the East and South Barrow Fields committed to domestic use in the North Slope Borough. (Copies of relevant pages attached as Exhibit B.)

other potential North Slope gas fields (e.g., Seal Island Area, Colville Delta Area); however, it makes clear that insufficient information is available to warrant assignment of any quantity of reserves--in short, these potential reserves are not something that regulators or the financial community would consider an adequate basis for a multi-billion dollar pipeline system.

3. Alaska Department of Natural Resources Estimate

Another source of proved reserves estimates is the Oil and Gas Division of the Alaska Department of Natural Resources ("ADNR"). Its most recent reserves figures for the North Slope are as follows for three alternative cases (low, middle-range, and high oil/gas prices):

ADNR Estimated Remaining Recoverable Reserves ^{1/}
(Billion cubic feet, dry)

<u>Proven and Developed</u>	<u>Low</u>	<u>Middle</u>	<u>High</u>
Endicott	590	790	1190
Kuparuk	420	570	720
Lisburne Reservoir	790	890	990
Prudhoe Bay Unit	26,000	26,000	26,000
<u>Proven but Undeveloped or Shut In</u>			
Point Thompson and Flaxman Island Areas	<u>0</u>	<u>0</u>	<u>5,000</u>
	27,800	28,250	33,900

^{1/} See ADNR, Historical and Projected Oil and Gas Consumption, January 1989, Table 2.1. The figures shown above include all quantities shown for locations on the North Slope except the 15 bcf of proved North Slope reserves committed to the North Slope Borough. (Copies of relevant pages attached as Exhibit C.)

The high-range ADNR estimate is reached only with the inclusion of 5 tcf of gas in the Point Thompson/Flaxman Island areas. In terms of transportability, this field stands in significant contrast to all of the others. Point Thompson/Flaxman Island is about 60 miles distant from the intended gas conditioning site at Prudhoe Bay; it has not been developed; its production characteristics are unknown; and gathering lines have not been installed. In short, it is not in the same "ball park," using ADNR's classifications, as the "proven and developed" reservoirs that currently are tied directly to central gas facilities at Prudhoe Bay. Major additional expenditures would be required to further define the field, develop the gas and transport it to a central conditioning plant.

4. Conclusion

Excluding the Point Thompson/Flaxman Island area gas, the combined EIA, AOGCC, ADNR range of North Slope proved, dry gas reserves is 22.5 to 28.3 tcf. Only with addition of the more costly, less certain Point Thompson/Flaxman Island gas could the total approach 33.9 tcf.

With ANGTS requiring at least 26 tcf of proved reserves, TAGS requiring at least 16 tcf, and additional gas required for production, gathering, conditioning, and compressor station fuel, the two projects obviously are mutually exclusive with respect to

transportable proved reserves in the same general time frame. ^{8/}

B. The Prudhoe Bay Gas is Needed Domestically

Alaskan Northwest has provided a plethora of evidence demonstrating that the proved, economically transportable reserves of North Slope gas will be needed in the lower-48 states by American consumers during Yukon Pacific's proposed period of export, i.e., 1996-2021. Alaskan Northwest demonstrated that the gas would be highly competitive on a free-market basis, without government subsidy, during that period. ^{9/} Alaskan Northwest sees no need to further burden the record with repetition or additional proof.

It is, however, necessary to set the record straight regarding certain Yukon Pacific statements made at the January 24 conference. Yukon Pacific, in attempting to defend the already discredited study by Dames and Moore and Decision Focus, Inc. ("D&M Study"), made numerous factually inaccurate statements concerning the conclusions reached in certain independent studies, as well as the feasibility of cost "levelization," which Alaskan Northwest intends to use. See Tr. 116-135.

At the January 24 conference, Yukon Pacific erroneously

^{8/} See f.n. 3 supra; Young and Hauser, p. 8, reference a study indicating 5.7 tcf are required to operate the Prudhoe Bay field and to provide fuel to operate the oil and gas pipeline systems.

^{9/} See the following: Comments, pp. 7-16; Reply Comments, pp. 25-39; Prepared Statements of January 24, 1989 by (1) Vernon Jones, pp. 3-11, (2) Cuba Wadlington, and (3) James Jensen, pp. 10-12.

stated that studies by the U.S. Department of Energy ("DOE"), the Potential Gas Committee ("PGC"), the United States Geological Service ("USGS") and the Gas Research Institute ("GRI") ". . . agree with the conclusion reached by our study that this [Alaskan North Slope] gas will not be economic, in the Lower 48 States, during the term of our export project." Tr. 92.

Yukon Pacific also asserted that the National Energy Board of Canada ("NEB") had stated: "[t]he year, 2017, under a high oil price is the first time that Canada expects Alaska North Slope gas to reach the Lower 48 states." Tr. 92-93. This representation is false, as discussed below. Yukon Pacific's assertions concerning the PGC and USGS can be readily dismissed by observing that both organizations deal with the magnitude of "undiscovered resources"--not with forecasts of deliverability by any specific dates. Neither organization prepares the natural gas economic supply/demand studies which would be required to reach the conclusion falsely attributed to it by Yukon Pacific.

Alaskan Northwest urges the ERA to disregard all such Yukon Pacific statements not fully proven in the record. Evidence to refute Yukon Pacific's undocumented, erroneous assertions is provided below:

1. GRI Projections

The GRI projects commencement of Alaskan pipeline gas flow in 2007. The basis for this statement is GRI's most recent forecast: 1988 Baseline Projection of U.S. Energy Supply and Demand to 2010, December 1988. The analytical work for this

study was completed before Alaskan Northwest's revised cost figures became available in June 1988. Even with the old, much higher costs, GRI projected ANGTS gas flow in 2007, i.e., squarely within the early part of Yukon Pacific's proposed period of export. This is documented in Exhibit D.

2. DOE Projections

A report entitled An Assessment of the Natural Gas Resource Base of the United States, May 1988, was prepared by the Argonne National Laboratory for DOE's Office of Policy, Planning and Analysis ("DOE/Argonne Report"). It was previously commented upon by Jensen Associates, Inc. See Alaskan Northwest's Comments, Exhibit A, pages 10-11. The report primarily is a survey of the nation's "resource" base, but it also concludes that large potential additions to reserves would be possible at a wellhead price of about \$3.00 per Mcf (1987 dollars). The Jensen comments observe that this implies a city gate price of "at least" \$3.50 in most major U.S. consuming markets. As demonstrated in Cuba Wadlington, Jr.'s Prepared Statement of January 24 (p. 6), Prudhoe Bay gas can be highly competitive in such a market.

3. NEB Projections

Yukon Pacific, at the January 24 conference, baldly misrepresented the contents of the recent study entitled Canadian Energy: Supply and Demand, 1987-2005, September 1988 ("NEB Report"). See Tr. 93.

Upon a diligent search of the NEB Report, no reference to Alaskan gas can be found. The study, in fact, is of Canadian gas, and detailed forecasts extend only to the year 2005--not beyond.

4. Alaskan Northwest's Cost Levelization

In direct contrast to uninformed opinions offered by Yukon Pacific representatives, Tr. 116-135, cost levelization is an approved and tested way to reduce the initial high cost of a "traditional tariff" and thereby ensure that gas is competitive in the marketplace. By analogy, if mortgage payments were not "levelized," virtually no homes would be purchased today in the United States. In 1984, the FERC issued an order to the Northern Border Pipeline Company authorizing use of a levelized tariff for the Eastern Leg of the "prebuilt" portion of the ANGTS. The Commission stated:

We believe . . . [that the levelized cost-of-service tariff] is in the public interest. The overall impact. . . is to make ANGTS 'prebuild' gas more price responsive in the United States markets. In addition [it] will provide rate stability . . . as well as a rate reduction in the near term. ^{10/}

Subsequent to that order, proposed new domestic gas pipeline projects have indicated an intent to use a levelized cost

^{10/} See Northern Border Pipeline Company, Docket No. RP85-25-000, "Order Accepting Certain Tariff Sheets Subject to Conditions," 29 FERC ¶61,303, p.61-629 (1984).

recovery method. ^{11/} Even more important in this proceeding is the fact that both the ANGTS and the proposed TAGS are more like international "mega-projects" than traditional utility rate base expansions, as Mr. Jensen testified at the January 24 conference. See Tr.28-29, 127-128. And no international project, to Alaskan Northwest's knowledge, has ever used the traditional but now outmoded domestic rate base methodology.

The fundamental point is that if gas is priced competitively in the marketplace, whether by levelization or by some other negotiated cost recovery method, it will be purchased. It should be obvious that levelization will not affect all sources of gas equally. Each project or source has a different remaining economic life, each exists at a different point in amortizing its incurred costs, and each has a different mix of wellhead and capital costs. Comparability among projects and sources for the purpose of determining market acceptability can be achieved only by considering prices actually offered to the market. For the ANGTS, it will be a levelized cost.

Yukon Pacific continues to tout its self-commissioned, self-serving D & M Study, which uses self-generated assumptions in discussing domestic need for the gas. In contrast, all of the independently developed forecasts by GRI, the American Gas Association, the Washington Policy and Analysis group, and others indicate a domestic need for the Prudhoe Bay gas by 2010 at the

^{11/} See, for example, Kern River Gas Transmission Company, Docket CP85-552; Mojave Pipeline Company, et al, Docket CP85-437; and Wyoming-California Pipeline Company, Dockets CP87-479/CP87-480.

latest. Accordingly, Yukon Pacific's D & M Study should be disregarded as a clearly faulty, biased work. 12/

5. Conclusion

For the foregoing reasons, Yukon Pacific's discredited assertions respecting the GRI, DOE, PGC, USGS, and NEB projections, as well as the alleged infeasibility of cost levelization must be rejected.

C. Insufficient Information is Available on Yukon Pacific's Proposed Project

Yukon Pacific's Application lacks, inter alia, the following: 13/

--gas purchase contracts--or firm letters of intent--for proved North Slope gas reserves

--gas sales contracts--or firm letters of intent--delineating the volumes of gas to be exported, the export recipients, and the terms and conditions of sale

--gas conditioning arrangements, including cost-sharing procedures and agreements for any joint-use of the Alaska Gas Conditioning Facility ("AGCF") conditionally FERC-certificated to the ANGTS (i.e., a facility which is also

12/ See Alaskan Northwest's Reply Comments, September 23, 1989, Exhibit G, A Critique of Yukon Pacific Corporation's Analysis of the Need for North Slope Natural Gas, by Jensen Associates, for a detailed assessment of the D & M Study.

13/ See Alaskan Northwest's Motion, pp. 25-44, for elaboration.

currently covered by a Corps of Engineers Section 404 permit for wetland construction and use of gravel).

--a complete environmental review of the gas conditioning arrangements, regardless of whether they will require an addition to existing/planned facilities or a new, stand-alone plant.

--specification of cost-sharing arrangements for other facilities (e.g., airfields, construction camps) intended to be used jointly with (and in many cases already permitted to) the ANGTS 14/

--a feasibility study regarding construction of TAGS in the Atigun Pass in addition to the existing oil pipeline, the state highway and the ANGTS. This raises a major cost sharing question in addition to feasibility and safety issues. 15/ Alaskan Northwest placed into the record at the January 24, 1989 conference a letter to the BLM spelling out its grave concerns with, inter alia, the Atigun Pass

14/ See Yukon Pacific, Project Description, December 1986, Section 5.2.15, pp. 113-119. Yukon Pacific, for example, specifically identifies facilities for its use that are currently permitted to the ANGTS.

15/ See Final Environmental Impact Statement for the Proposed Trans-Alaska Gas System ("FEIS"), June 1988, Appendix B. In assessing the compatibility of TAGS with other pipeline systems, BLM's Compatibility Review Team stated: "While a final compatibility determination can be made only after a detailed design has been developed . . . the engineering design solution for two chilled gas pipelines through the [Atigun] pass must be coordinated prior to construction of the first gas pipeline to be built." (p. B-6)

area. 16/ It is Alaskan Northwest's firm position, based on expert engineering and construction advice, that construction of a second gas pipeline in Atigun Pass might be feasible (if at all) only if the construction is accomplished at the same time the first gas pipeline is constructed. Such simultaneous construction raises, in addition to engineering issues, obvious cost-sharing and regulatory issues including possible application of Sections 4, 5, 7 and 16 of the Natural Gas Act ("NGA").

--complete identification of all project participants, including corporate and other affiliations.

--evidence of technical and financial capability to engineer, finance and construct the largest LNG project to date in the world. 17/

III. LEGAL BASIS FOR PROPOSED CONDITIONS

As Alaskan Northwest has previously documented, the failure of Yukon Pacific to present sufficient record evidence in support of its Application compels denial of the requested export application. On the assumption, however, that the ERA may consider issuance of some form of preliminary authorization, the

16/ See Northwest Alaskan Pipeline Company letter (ALO-86-4099) of December 22, 1986, addressed to Mr. Arlan H. Kohl, BLM.

17/ At the January 24, 1989, conference, the Yukon Pacific representative refused to divulge the investment in TAGS to date (estimated by some at less than \$2 million, including all public relations expenditures). See Tr. 209.

breadth of the legal requirements prescribed by the various statutes implicated by the Application requires the attachment of certain protective conditions. Accordingly, Alaskan Northwest provides the following legal analysis in support of such necessary protective conditions.

A. Section 3 of The Natural Gas Act

With respect to any application to export natural gas, Section 3 of the NGA requires the ERA to find, based upon substantial evidence, that the proposed export is in the public interest. Such evidence must include an examination of: the adequacy of gas reserves to support the proposed export; the lack of demand for the export volumes in the lower 48 states; environmental considerations; and claimed benefits (or, at a minimum, absence of harm) to U.S. consumers and ratepayers. See 10 C.F.R. §590.201, et seq.

Evidence has not been adduced to support any asserted claim that the proposed export is in the public interest. In many critical respects, the inability or unwillingness of the TAGS sponsors to provide a more complete record leaves the ERA to discharge its Section 3 review responsibilities in a vacuum. Nevertheless, should the agency be resolved to issue some form of preliminary permit, the parameters of any such authorization are necessarily circumscribed given the absence of the requisite substantial evidence.

Yukon Pacific's failure to provide contracts for the purchase of North Slope reserves and for the resale of exported volumes

has foreclosed any meaningful review of several considerations relevant to the "public interest." Evidence has not been presented identifying the export markets, the terms and conditions of sale, the conditioning and delivery arrangements, and the lack of domestic need for these gas supplies. Accordingly, the impact on the trade deficit, international relations, U.S. energy security and the related economic, environmental and socio-economic consequences cannot be assessed. Issuance of an unconditional export permit simply cannot be defended under the public interest standard.

Accordingly, under the "plenary authority" provided to the ERA under Section 3, a full range of certificate-type conditions must attach to the extent some form of preliminary export authorization is contemplated. See Distrigas Corporation v. F.P.C., 495 F. 2d 1057 (D.C. Cir.), cert. denied, 419 U.S. 834 (1974). ^{18/} These conditions, set forth herein, would include (among others) supplementation of the deficient Application, as well as mandatory conditions which would ensure that, for the life of the project (and in the event of domestic need) the proposed exports would not result in any adverse impact on ANGTS or the incurrence of any additional costs by U.S. consumers and ratepayers. Additionally, continuing oversight authority should

^{18/} See also Delegation Order No. 0204-25, para. (a) (1)-(5), 43 Fed. Reg. 47,769 (Oct. 17, 1978): "In exercising the functions [of determining whether importation or exportation of natural gas is not inconsistent with the public interest], the Administrator may attach such terms and conditions as he shall determine to be necessary to make the import or export not inconsistent with public interest. . . ."

be retained by ERA, e.g., by imposition of a condition permitting the ERA to withhold, modify or suspend the final export authorization as required by the public interest or as necessary to preserve the jurisdictional powers of the ERA and/or FERC.

B. Alaska Natural Gas Transportation Act of 1976 ("ANGTA")

ERA's review responsibilities are compounded and expanded by other statutory provisions, including the ANGTA. These statutory mandates impose on the ERA further restrictions with regard to the permissible scope of any forthcoming export authorization.

The provisions of Sections 9 and 12 of ANGTA define and limit the nature of North Slope exports which may be authorized, with due consideration for the priorities and protections provided to the ANGTS. Specifically, in pertinent part, Section 9 of ANGTA prohibits any federal action which would ". . . prevent or impair in any significant respect the expeditious construction and initial operation" of the ANGTS. Section 12 of the ANGTA requires, as a precondition to any export authorization, a specific finding that a proposed export of Alaskan gas to countries other than Mexico or Canada would not "diminish the total quantity or quality nor increase the total price of energy available to the United States." As detailed below, these congressionally mandated safeguards cannot be enforced in the absence of permit conditions protecting the North Slope reserves relied upon and needed for the successful development of ANGTS.

1. Section 9

Alaskan Northwest has demonstrated, on the record, that available, proved and deliverable North Slope reserves will only justify construction of one project in the time frame envisioned. ^{19/} In any event, however, a proposed protective condition is required regardless of the amount of ultimately available reserves. Until such time as North Slope gas actually begins to flow (whether in interstate or foreign commerce), there can be no assurance, short of the proposed protective condition, that the Section 9 protection--i.e., no impairment of initial ANGTS construction or operation--will be honored. Stated differently, because the North Slope reserve base identified in prior ANGTS-related legislative, executive, and regulatory approvals will form the basis for all underlying financing arrangements necessary for the "initial construction and operation" of the ANGTS, any actual or threatened depletion of such reserves would undermine the economic viability of the ANGTS project.

Other issues are directly implicated, and subject to the ERA's mandatory review by virtue of Section 9 of ANGTA. For example, unless a comprehensive analysis is forthcoming with respect to possible parallel construction of TAGS and ANGTS and possible joint use of the conditionally certificated gas

^{19/} See discussion at Part II.A., supra.

conditioning facility proposed as part of the ANGTS, ^{20/} the requested export authorization cannot issue. Such issues, and other issues which could potentially impact the capital and/or operating costs of the ANGTS, fall directly within the purview of Section 9 and therefore demand mandatory scrutiny.

2. Section 12

As previously documented, the legislative history of Section 12 of ANGTA indicates Congress' intent to permit the export of North Slope reserves only in the context of an exchange resulting in the delivery of an equivalent amount of comparably priced energy to the United States. See, Alaskan Northwest Comments, pp. 23-28. By interposing a specific Section 12 finding--i.e., that a proposed export will not reduce the quantity or quality of domestic energy or increase prices to U.S. consumers--as a prerequisite to any export authorization, Congress clearly contemplated the exportation of North Slope reserves only contemporaneous with importation of thermally equivalent and comparably priced energy supplies.

Nevertheless, apart from whether or not North Slope exports can only be approved in the context of an exchange, the ERA must, at a minimum, find that the proposed export will not require U.S. consumers to suffer curtailments or pay prices for either oil,

^{20/} See Order Amending Conditional Certificate, 18 FERC ¶ 61,002 (1982), incorporating certificate revisions mandated by Waiver of Law, S.J. Res. 115, Pub. L. No. 97-93, 97th Cong. 1st Sess. (1981) and, specifically, inclusion of conditioning plant as part of approved ANGTS.

gas or other alternative supplies where the costs associated therewith will be higher than the cost of Alaskan gas delivered to the lower 48 states during the term of the proposed export. Consequently, consistent with the ERA's own preliminary findings, the Yukon Pacific export proposal may not proceed in the absence of a detailed examination of U.S. demand through the first quarter of the next century. Evidence presented to date on the domestic need issue contains expert forecasts of U.S. domestic need for the North Slope gas by independent organizations, including government agencies, on the one hand, and, at best, a questionable analysis by Yukon Pacific asserting the absence of need on the other. Without a more convincing demonstration that there is no domestic need, the ERA is not equipped to render the necessary Section 12 findings to support an unconditional export permit.

Yukon Pacific makes much of the January 12, 1988 Presidential Finding ("Finding"), going so far as to contend that such finding preempts the ERA from further consideration of the range of issues which otherwise arise under Section 12 of ANGTA. Contrary, however, to the arguments advanced by Yukon Pacific, the Finding is neither project nor reserve specific and, by its own terms, does not attempt to "assess the merits or feasibility of any particular project." Additionally, the Finding includes no determination that the proposed exports are in the public interest, or that adequate reserves exist to support both the TAGS and the ANGTS.

On the contrary, by declaring that any export project "should

not hinder completion of the ANGTS," the President reaffirmed the federal government's long-standing support for the ANGTS. The expansive interpretation urged by Yukon Pacific--i.e., that the Finding relieves the ERA from review responsibilities with regard to issues arising under Section 12 of the ANGTA--was properly rejected by the ERA as reflected in the July 25, 1988 and December 5, 1988 orders. Specific findings, supported by substantial evidence, on issues such as magnitude of reserves, domestic need, and environmental and economic ramifications of parallel construction are prerequisite--under Section 12--to any export permit issued.

C. National Environmental Policy Act of 1969 ("NEPA")

Another obvious impediment to authorization of TAGS concerns the sponsors' failure to provide descriptive data and analysis mandated by the NEPA. At least two interested governmental entities (the Environmental Protection Agency ("EPA") and the FERC), have cited the inadequacy of the June 1988 FEIS for TAGS and, in particular, its failure to address environmental consequences associated with construction and operation of gas conditioning facilities. EPA stated: "the air quality analysis must be deferred to a future NEPA review." 21/ And the concerns previously raised by FERC's environmental evaluation branch

21/ See letter dated June 13, 1988 from the EPA to BLM, attached as Exhibit B to Alaskan Northwest's Reply Comments.

remain entirely unresolved. ^{22/} BLM, with its FEIS, has in effect passed the buck to ERA.

There is no evident dispute that authorization of the TAGS project constitutes a "major federal action" triggering the full panoply of NEPA requirements. To date, however, the TAGS sponsors have attempted to evade NEPA's manifest intent, at least concerning the admittedly necessary gas conditioning complex at Prudhoe Bay. Short of providing ". . . environmental disclosure sufficiently detailed to aid in the substantive decision whether to proceed with the project in light of its environmental consequences . . ." (Trout Unlimited v. Morton, 509 F.2d 1276, 1282 (9th. Cir. 1974)), the BLM's FEIS contains the unsupported observation that "[l]ittle additional land use impacts would occur [assuming construction of a second major conditioning plant] because the modification from subsistence and undisturbed wilderness to a petroleum complex has already taken place." P. 4-116.

As Alaskan Northwest has demonstrated, the ERA cannot legally or responsibly proceed to decision on the request for an unconditional export authorization so long as the environmental consequences associated with the multi-billion dollar conditioning installation--covering approximately 200 acres of fragile wetlands and requiring the mining of 2 million cubic yards of gravel--remain unaddressed. See Trout Unlimited, supra;

^{22/} See letter dated August 7, 1987 from FERC's Environmental Evaluation Branch to BLM, portions attached as Exhibit D to Alaskan Northwest's Reply Comments.

see also Sierra Club v. Cavanaugh, 447 F. Supp. 427 (D.S.D. 1978)

The standards by which environmental impact statements are to be tested were recently considered in Town of Huntington v. Marsh, 859 F.2d 1134 (2nd Cir. 1988). In Marsh, the court found inadequate the EIS prepared by the Army Corps of Engineers in connection with applications for dumping permits authorizing the disposal of dredged waste in the Long Island Sound. The Corps contended that its EIS properly and sufficiently addressed those environmental issues within the "scope of the project"--i.e., according to the Corps, consideration of the appropriate disposal site. The Court rejected such contention, finding that the " . . . fundamental flaw in the Corps' EIS is its too circumscribed view of the 'project' which is the subject of its impact statement. . . [and its failure] to insure that interrelated projects, the overall effect of which is environmentally significant, not be fractionalized." Id. at 1142. According to the Court, the Council on Environmental Quality ("CEQ") guidelines, promulgated under NEPA and set forth at 40 C.F.R. § 1502, et seq., require all "connected actions"--i.e., actions "closely related such that they are interdependent parts of a larger action and depend on the larger action for their justification" to be encompassed within the FEIS. Id. The applicable test is whether a specific project (or, by analogy, a specific component of a project) has independent utility. Id.

That the TAGS conditioning facility constitutes a "connected action" subject to mandatory FEIS inclusion under Marsh cannot credibly be challenged. The conditioning facility has "no

independent utility" separate and apart from the export project. Its very existence is inextricably tied to the operation and construction of TAGS. Accordingly, unless and until the FEIS is supplemented to include in-depth, comprehensive consideration of the TAGS conditioning installation (i.e., well beyond the few pages of cursory discussion in the FEIS), the requested export permit may not issue.

D. Sections 4, 5, 7 and 16 of the Natural Gas Act

1. Joint-Use of the Alaska Gas Conditioning Facility

President Reagan's proposed Waiver of Law ("Waiver") was submitted to Congress on October 15, 1981, pursuant to Section 8(g) of ANGTA. Shortly thereafter, Congress approved the proposed Waiver by Joint Resolution, and it was signed into law by the President. S.J. Res. 115, Pub. L No. 97-93, 97th Cong. 1st Sess. (1981). As discussed below, the legislative history of the Waiver contemplated not only FERC-required certificate modifications, but also the need for FERC to undertake cost-allocation and rate design review in the event of joint-use of the AGCF.

In pertinent part, the Waiver amends the President's Decision of September 1977, on the ANGTS, to "include the gas conditioning plant [i.e., the AGCF] in the approved transportation system" for the delivery of North Slope gas to the Lower-48 states. Accordingly, by order issued January 4, 1982, 18 FERC ¶61,002 (1982), the FERC amended the conditional certificate issued

December 16, 1977 to reflect inclusion of the gas conditioning plant as part of the "Alaska segment" of the ANGTS.

On May 27, 1977, the FERC issued a Declaratory order in Yukon Pacific Corporation, Docket No. GP87-16-000. Although subject to numerous caveats and qualifications, ^{23/} the Commission nonetheless found--on the record before it--that the Yukon Pacific export proposal did not invoke the Commission's jurisdiction under the NGA. This finding was expressly qualified in recognition of the uncertainties surrounding conditioning arrangements for the proposed export volumes. In the Commission's words:

It is also not clear whether the gas conditioning plant proposed to be used by the TAGS sponsors is the same plant for which the ANGTS sponsors have already received a conditional certificate under Section 7 of the NGA, or whether it is a different and totally unrelated plant. If we had jurisdiction to certificate the project, such factual uncertainties would necessarily mandate an evidentiary hearing before issuance of a certificate could be considered.

39 FERC at p. 61,754 (emphasis added).

And, elsewhere in the same order, the Commission noted:

If Yukon Pacific subsequently decides to utilize Alaskan Northwest's conditionally-certificated AGCF, the matter of Section 7 jurisdiction would have to be re-examined We stress again, that this conclusion [i.e. no Section 7 jurisdiction] is premised on all of the factual predicates discussed above, including the facts regarding the conditioning plant, the configuration of the pipeline, and the sources of the gas.

Id. at pp. 61,757-61,758 (emphasis added).

^{23/} See, e.g., 39 FERC at 61,754 ". . . issuance of a declaratory order does not have finality or the consequences of a certificate [and] . . . determination[s] made today can only be valid within the parameters of the facts and factual predicates before us . . . any material change in those facts could well affect our jurisdiction"

The conditioning arrangements for TAGS exports are no more definitive today than they were in December 1986, when Yukon Pacific's declaratory order petition was originally filed. The TAGS sponsors continue to hedge in their most recent filings, to the extent conditioning plans are even discussed. Clearly, however, as the Commission acknowledged, a host of jurisdictional issues--not heretofore decided by the FERC or the ERA--will immediately come into focus in the event TAGS at some point announces its intention to use the AGCF. Thus, for example, if the jurisdictional AGCF is eventually used by TAGS jointly with Alaskan Northwest, the commingling of Yukon Pacific's export volumes with the ANGTS interstate volumes in the AGCF could subject the entire TAGS pipeline facilities to regulation as an interstate jurisdictional facility under the Natural Gas Act. See California v. Lo-Vaca Gathering Company, 379 U.S. 366 (1965); see also State of Louisiana v. F.P.C., 533 F.2d 1239 (D.C. Cir. 1976), and Louisiana Power and Light Company v. F.P.C., 483 F.2d 623 (5th Cir. 1973), cert. denied 416 U.S. 974 (1974). ^{24/}

^{24/} As documented earlier in these proceedings by Alaskan Northwest, Yukon Pacific's treatment of the gas conditioning issue has been a sorry example of obfuscation and misstatement. First, Yukon Pacific's own President filed an application with the BLM that specified in precise words its intended use of the FERC-certificated AGCF; and Yukon Pacific's own Chairman executed a formal agreement with BLM for preparation of an EIS covering its project, which was specifically described as including gas conditioning. Yukon Pacific then filed with FERC an application for a declaratory order in which it was asserted that the AGCF would not be used and that a separate, stand-alone facility would be built. Thus, there were simultaneously pending before two federal agencies flatly contradictory applications. At the
(Footnote Continued)

The potential joint use of the AGCF also raises cost allocation issues cognizable under Sections 4 and 5 of the NGA, as Congress acknowledged in enacting the Waiver. The Committee report accompanying the recommendation to approve the proposed Waiver addresses the implications of possible joint use of the AGCF, stating:

. . . FERC in determining tariff provisions applicable to the gas conditioning facility for ANGTS purposes will have to decide the proper allocation of costs among various users. The Committee intends that FERC will carefully review all of the allowable costs in the ANGTS proceedings to ensure that only those properly allocated to transportation of the Alaskan natural gas through ANGTS will be included in the ANGTS tariff.

Sen. Rep. 97-272, accompanying S.J. Res. 115, pp. 33-34.

Thus, because TAGS exports may ultimately be processed and conditioned through the AGCF, FERC's Sections 4, 5 and 7 authority is directly implicated. Pending resolution of these cost allocation (and certificate) issues--i.e., by requiring TAGS to specify, once and for all, proposed conditioning arrangements and directing referral to the FERC in the event joint use of the AGCF is contemplated--there can be no assurance that U.S.

(Footnote Continued)

January 24 hearing, Yukon Pacific's attempt to shield from agency scrutiny its fatal "Achille heel" was once again evident. The gas was to be conditioned in an "add on" facility, but it would be someone else's facility. See Tr. 196-200. As pointed out, however, the courts have made clear that ownership of a facility is not relevant to applicability of NEPA. And, moreover, if gas commingling occurs in such an "add on" to the AGCF, the entire jurisdictional issue is open. If an entirely new, stand-alone facility is built to process only TAGS gas, such facility is equally a "connected action" to the export project, and NEPA requires completion of the EIS for such "stand-alone" facility. Even an add-on facility would require substantial additional facilities and could have a significant cumulative environmental effect. This requires an assessment as to whether such expansion of existing facilities requires reopening the NEPA process.

consumers and ratepayers will not eventually subsidize the costs of any such conditioning and processing. The regulatory hiatus created by TAGS' noncommittal posture respecting conditioning arrangements must not result in deviation from the long-standing rate-making principle (endorsed by Congress in connection with the Waiver) requiring the assignment and allocation of costs to those customers on whose behalf such costs are incurred. See, e.g., Colorado Interstate Gas Co. v. F.P.C., 324 U.S. 581, 591 (1945) (upholding the principle that "beneficiaries of entire project [must] share equitably in the cost"). Accordingly, at a minimum, the ERA must attach appropriate protective conditions to any export authorization requiring, as necessary, final FERC determinations on jurisdictional and rate issues under Sections 4, 5, 7 and 16 of the NGA if the AGCF is ultimately used by TAGS.

2. Atigun Pass Facilities & Other Joint-Use Issues

As discussed, supra, several factual engineering and construction issues arise in connection with TAGS' proposed construction of pipeline facilities through the Atigun Pass. The proposed routing of TAGS in this area coincides with the routing of the conditionally approved ANGTS. Accordingly, given the engineering impracticability of sequential construction of large diameter pipeline facilities through the Atigun Pass, ^{25/} either simultaneous construction of both TAGS and ANGTS, or rerouting of one or the other, may be required. Consequently, should TAGS

^{25/} See factual discussion Part II. C., supra.

undertake construction of proposed facilities prior to initial construction and operation of ANGTS, forced simultaneous construction by TAGS of conditionally-certificated ANGTS facilities through the Atigun Pass may be required in order to ensure compliance with Section 9 of ANGTA. Any such construction would invoke the Commission's Section 7 authority requiring TAGS to first obtain a certificate of public convenience and necessity. Likewise, to the extent that authorization of TAGS forces rerouting of the conditionally certificated ANGTS facilities (assuming, arguendo, that such rerouting may be ordered consistent with Section 9 and 12 of ANGTA), an amendment to the ANGTS conditional certificate would be necessary to reflect (and provide authorization for) any such routing deviation.

Finally, cost allocation issues are posed by the proposed joint use by TAGS of ancillary facilities located between Prudhoe Bay and Delta Junction that are to be used by ANGTS (and in many cases are already permitted to ANGTS). Thus, joint use of airstrips, construction camp sites, material sites, communication facilities, erosion control structures, access roads and the like by TAGS and ANGTS must be carefully analyzed (prior to any export authorization) to ensure that U.S. consumers and ratepayers bear none of the costs associated with TAGS.

IV. PROPOSED CONDITIONS

In light of the deficiencies associated with the Application, protective conditions must attach to any ERA authorization issued

to ensure that the mandates of the NGA, the ANGTA, and NEPA are not contravened. Thus, if the ERA is resolved to issue some form of preliminary authorization, the following conditions, inter alia, must be imposed:

1. The authorization granted herein is conditional and will not become final except by a subsequent order of ERA. In order to obtain a final export authorization, Yukon Pacific must file and serve upon all parties of record, the following information:
 - (a) gas purchase, sales and transportation contracts, or firm letters of intent, setting forth the gas reserves proposed to be purchased, transported and resold;
 - (b) qualified reservoir engineering studies, by producing field, including proven reserves and daily and annual deliverability studies for the reserves relied upon by TAGS;
 - (c) definitive siting, engineering and design data; gas conditioning specifications; and cost and ownership information on proposed conditioning facilities;
 - (d) proposed definitive design, engineering and construction plans for Atigun pass demonstrating feasibility of such construction and measures to be taken to preclude rerouting the ANGTS, including any simultaneous construction of TAGS and ANGTS facilities, together with any proposed cost-sharing arrangements;
 - (e) identification of all other proposed joint-use facilities and proposed cost-sharing arrangements; and
 - (f) a definitive analysis of the net national economic benefits of the proposed exports.
2. No final authorization shall issue until such time as the ERA evaluates all supplemental data required by Condition 1 above, and concludes that:
 - (a) the Application satisfies the "public interest" under Section 3 of the Natural Gas Act, 15 U.S.C. Sec. 717b;
 - (b) no further actions are required under the provisions of the National Environmental Policy Act of 1969, 42 U.S.C. 4231, et seq., with respect to the export application;
 - (c) consistent with the requirements of Sections 3, 4, 5, 7 and 16 of the Natural Gas Act, 15 U.S.C. Sec. 717, et seq., the Federal Energy Regulatory Commission has rendered all

final necessary determinations within the scope of its jurisdiction over the proposed TAGS project pursuant to Sections 3, 4, 5, 7 and 16 of the Natural Gas Act; and

- (d) consistent with Sections 9 and 12 of the Alaska Natural Gas Transportation Act, 15 U.S.C. Sec. 719g and 719j, authorization of the proposed export will not, during the term of the authorization, compel a change in the basic nature and general route of the Alaska Natural Gas Transportation System nor otherwise prevent or impair in any significant respect the expeditious construction and operation of that system; and that authorization of the proposed export will not, during the term of the authorization, operate to diminish the total quantity or quality or increase the total price of energy available to the United States.
3. Any final export authorization is subject to suspension, modification, or revocation upon the demonstration to the Economic Regulatory Administration, or any successor entity, of a reasonable likelihood that continuation of the authorized exports is no longer consistent with the findings made pursuant to Condition 2 above.

V. CONCLUSION

The ERA cannot proceed to decision on the merits of the Application without due regard for the review responsibilities imposed by the NGA, ANGTA, and NEPA. Together, these statutes require, at a minimum, that any export authorization granted to Yukon Pacific be grounded on specific findings supported by substantial evidence.

The requisite findings essential to ERA's deliberations include that: (i) the TAGS Application fully complies with all NEPA requirements; (ii) no domestic need will arise during the term of the proposed export; (iii) permitting of TAGS will not compel a change in the general routing of ANGTS or otherwise prevent or impair in any significant respect the expeditious construction and operation of the ANGTS; (iv) permitting of TAGS

will not diminish the total quantity or quality or increase the total price of energy available to the U.S.; and, (v) FERC's jurisdiction under Section 3, 4, 5, 7 and 16 is not invoked by the Application.

On the record established to date, these requisite findings cannot be made, and the Application should be denied. Alaskan Northwest, nevertheless provides, in response to ERA's request, proposed conditions (in Part IV, supra) to attach to any conditional authorization which may be contemplated.

Alaskan Northwest expressly reserves the right to propose additional conditions as may be necessary following the submission by Yukon Pacific of information in further support of the TAGS project.

Respectfully submitted,



William J. Moses
General Counsel

NORTHWEST ALASKAN PIPELINE COMPANY
Operating Partner for Alaskan
NORTHWEST NATURAL GAS
TRANSPORTATION COMPANY
3111 C Street, Suite 200
Anchorage, Alaska 99503

February 7, 1989

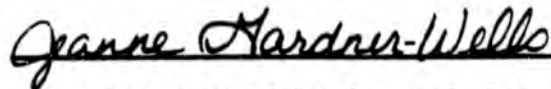
VERIFICATION

William J. Moses, being first duly sworn, deposes and says that he is General Counsel of Northwest Alaskan Pipeline Company, operating partner of the Alaskan Northwest Natural Gas Transportation Company, and that as such he is authorized to sign and verify the foregoing document; that he has read said document and is familiar with the contents thereof; and that the matters and things set forth therein are true and correct to the best of his information, knowledge and belief.



William J. Moses

SUBSCRIBED AND SWORN TO before me this 7th day of February, 1989.



Notary Public in and for
the District of Columbia

Jeanne Gardner-Wells
Notary Public, District of Columbia
My Commission Expires Jan. 12, 1993

CERTIFICATE OF SERVICE

I hereby certify that I have on this day, pursuant to Section 590.107 of the regulations, served the foregoing document upon the ERA, the Applicant, and the parties appearing on the official service list by first-class mail, postage prepaid.

Dated at Washington, D.C. this 7th day of February, 1989.

A handwritten signature in dark ink, appearing to read 'W. J. Moses', is written over a horizontal line.

William J. Moses

EXHIBIT A



DOE/EIA-0216(87)
Distribution Category UC-98

U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves

1987 Annual Report

**Energy Information Administration
Office of Oil and Gas
U.S. Department of Energy
Washington, DC 20585**

**NOTE: PAGES Attached (only):
Inside Cover Page, 25,
29-30, 102-104.**

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4. National and State Natural Gas Statistics

Natural Gas Proved Reserves

Table 8 presents the estimated proved reserves, reserve changes, and production of natural gas, wet after lease separation, as of December 31, 1987, by selected States and State subdivisions. Total proved reserves of natural gas, wet after lease separation, were 196,428 billion cubic feet, a decrease of 4,681 billion cubic feet or 2.3 percent lower than reported in 1986. This decrease brings total U.S. proved reserves of natural gas to the lowest level since the EIA's initial estimate for year-end 1976. Total proved reserves of natural gas, wet after lease separation, in the lower 48 States decreased 3.0 percent (5,041 billion cubic feet) in 1987. Total wet natural gas production increased 3.1 percent (503 billion cubic feet) during 1987 as a result of higher demand. Total discoveries from new fields, new reservoirs in old fields, and extensions decreased by 19.6 percent (1,834 billion cubic feet). Extensions showed a particularly sharp drop (24.2 percent) to 4,818 billion cubic feet.

The estimated proved reserves of nonassociated natural gas, wet after lease separation, as of December 31, 1987, by selected States and State subdivisions are presented in Table 9. Proved reserves of nonassociated natural gas in the United States declined by 3,293 billion cubic feet (2.3 percent) to 138,239 billion cubic feet in 1987. Production of nonassociated gas increased by 4.6 percent (595 billion cubic feet). Total discoveries from new fields, new reservoirs in old fields, and extensions decreased significantly by 19.3 percent (1,606 billion cubic feet) in 1987. The most important factor in the lower 48 States total discoveries was a decline in field extensions of 23.7 percent to 4,276 billion cubic feet. Much of this decline was in the Federal Offshore where extension drilling was not as successful as in the previous year.

Table 10 presents the estimated proved reserves of associated-dissolved natural gas, wet after lease separation, as of December 31, 1987, by selected States and State subdivisions. Proved reserves of associated-dissolved natural gas in the United States declined by 2.3 percent to 58,189 billion cubic feet while production fell by 2.7 percent. Proved reserves of associated-dissolved natural gas in the lower 48 States declined 4.3 percent to 27,457 billion cubic feet while production declined 3.5 percent.

Estimates of proved natural gas reserves on a dry basis are shown in Table 11. During 1987, proved reserves of dry natural gas declined 4,375 billion cubic feet, or more than 2.3 percent. This decrease brings total U.S. proved dry gas reserves to the lowest level since the EIA's initial estimate

for year-end 1976. Alaskan proved reserves of dry natural gas increased by 561 billion cubic feet or 1.7 percent. U. S. proved reserves of dry natural gas in the lower 48 States, however, decreased by 3.1 percent (4,936 billion cubic feet) in 1987. Production of dry natural gas was up 3.2 percent to 16,114 billion cubic feet for the year. Total discoveries of dry gas reserves were down 19.7 percent to 7,175 billion cubic feet in 1987, the lowest discovery level during the 1977 through 1987 period. New field discoveries were roughly flat at 1,089 billion cubic feet, but still 57.1 percent lower than the 1977 through 1986 annual average of 2,539 billion cubic feet. Both extensions (4,587 billion cubic feet) and new reservoirs discovered in old fields (1,499 billion cubic feet) were substantially down in 1987.

The volumetric difference between the estimates reported in Tables 11 and 8 is the result of the removal of natural gas liquids at natural gas processing plants. The methodology used to adjust for plant liquids production is described in Appendix B. All natural gas reserves data in this report exclude natural gas held in underground storage.

Alaskan North Slope Natural Gas Reserves

Background

There has been an ongoing economic reassessment by the companies involved of the Alaskan North Slope gas resources for several years. In 1987, the two major Alaskan operating companies agreed that, given the current outlook and economic conditions, only gas that was marketable on the North Slope could be classified as proved reserves. Current economic conditions include uncertainties that exist with respect to a transportation system or other marketing alternatives for the gas. However, the downward revisions to proved reserves on the Alaskan North Slope reported in 1987 and prior years by the operating companies have not been accepted by EIA and are not reflected in the proved reserve estimates presented for 1987. Therefore, as in past years, EIA proved reserves of dry natural gas include some 24.6 trillion cubic feet located on the Alaskan North Slope that do not, at present, have a market.

Proposed plans for exploitation of the natural gas are still being formulated, but a market does not currently exist for the bulk of these reserves. However, produced natural gas currently creates and will continue to create a positive net cash flow from stripped liquids and as fuel for field operations and the Trans-Alaska Pipeline. The gas also has value

Table 11. Estimated Total Dry Natural Gas Proved Reserves, Reserves Changes, and Production, 1987
(Billion Cubic Feet, Dry, at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/86	Changes in Reserves During 1987							Proved Reserves 12/31/87
		Net Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries In Old Fields (+)	Production (-)	
Alaska	32,664	202	718	67	45	12	0	349	33,225
Lower 48 States	188,922	1,986	18,809	14,164	4,642	1,077	1,499	16,785	183,986
Alabama Onshore	951	-154	161	57	39	0	2	100	842
Arkansas	1,992	26	215	229	93	0	29	129	1,997
California	3,928	-69	315	136	44	1	2	345	3,740
Coastal Region Onshore	255	-14	34	15	2	0	0	24	238
Los Angeles Basin Onshore	142	9	21	9	2	0	0	17	148
San Joaquin Basin Onshore	3,277	-63	246	102	33	1	2	292	3,102
State Offshore	254	-1	14	10	7	0	0	12	252
Colorado	3,027	-77	340	268	71	7	1	159	2,942
Florida	49	7	0	0	0	0	0	7	49
Kansas	10,509	239	245	147	76	8	1	437	10,494
Kentucky	841	68	65	17	10	0	0	58	909
Louisiana	12,930	156	1,655	1,414	414	16	298	1,625	12,430
North	2,515	-13	247	259	127	1	4	316	2,306
South Onshore	9,103	-121	1,270	1,005	272	6	277	1,109	8,693
State Offshore	1,312	290	138	150	15	9	17	200	1,431
Michigan	1,139	35	160	157	257	90	57	130	1,451
Mississippi	1,300	5	153	96	32	1	3	178	1,220
Montana	803	-25	57	16	2	0	1	42	780
New Mexico	11,808	-76	1,123	650	131	1	11	728	11,620
East	2,694	185	524	222	71	0	11	382	2,881
West	9,114	-261	599	428	60	1	0	346	8,739
New York	457*	-11	3	17	0	1	0	23*	410
North Dakota	541	-3	83	64	5	2	1	57	508
Ohio	1,420	-260	45	35	12	0	4	117	1,069
Oklahoma	16,685	559	2,251	2,047	823	11	242	1,813	16,711
Pennsylvania	1,560	164	109	195	137	0	0	128	1,647
Texas	40,574	438	4,477	4,009	1,326	177	245	4,517	38,711
RRC District 1	913	-7	74	62	9	1	14	130	812
RRC District 2 Onshore	2,180	320	300	280	58	20	24	349	2,273
RRC District 3 Onshore	3,753	-5	518	349	146	119	19	569	3,632
RRC District 4 Onshore	8,274	5	1,127	1,599	701	11	129	1,158	7,490
RRC District 5	2,141	31	151	112	79	0	0	171	2,119
RRC District 6	4,854	68	366	269	47	5	6	395	4,882
RRC District 7B	684	96	59	58	16	0	6	106	697
RRC District 7C	2,721	137	244	192	22	5	13	242	2,708
RRC District 8	7,333	-120	634	308	62	7	24	633	6,999
RRC District 8A	845	72	72	44	2	0	0	71	876
RRC District 9	868	-7	118	68	35	0	0	112	834
RRC District 10	5,276	-129	742	572	108	4	4	471	4,962
State Offshore	732	-23	72	96	41	5	6	110	627
Utah	1,895	-45	281	144	12	5	3	60	1,847
Virginia	253	2	5	8	15	0	0	19	248
West Virginia	2,148	154	137	134	92	0	13	188	2,242
Wyoming	9,756	38	771	425	318	5	16	456	10,023
Federal Offshore ¹	34,223	-27	4,154	3,998	632	752	557	4,462	31,931
Pacific (California)	1,325	163	53	49	6	0	0	46	1,452
Gulf of Mexico (Louisiana) ¹	25,454	-314	2,547	2,770	489	701	386	3,213	23,260
Gulf of Mexico (Texas)	7,444	124	1,554	1,079	157	51	171	1,203	7,219
Miscellaneous ²	133	-78	4	1	1	0	13	7	65
U.S. Total	191,598	1,986	17,527	14,231	4,857	1,989	1,499	16,114	187,211

¹ Includes State and Federal offshore Alabama

² Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Oregon, South Dakota, and Tennessee

* Indicates that the estimate is associated with a sampling error (95 percent confidence interval) which exceeds 20 percent of the estimated value.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves", and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production". They may differ from the official Energy Information Administration production data for natural gas for 1987 contained in the *Natural Gas Annual 1987*, DOE/EIA-0131(87).

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves", and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production".



Jackup Rig in Cook Inlet, Alaska.

by increasing the recovery of crude oil through reinjection for pressure maintenance and tertiary recovery operations. There is no question about the technical and low cost producibility of the associated-dissolved gas through the wellhead. For example, in the giant Prudhoe Bay Field, most of the gas could be produced through wells that have already been drilled.

Definitional Aspects

The EIA reviewed the situation within the context of definitional differences used to describe the classification of natural gas reserves located in fields on the North Slope of Alaska. The majority of these volumes continue to be included in the 1987 estimates of proved reserves presented in this report. With respect to the EIA proved reserves definition, it is worth noting that the following language provided significant latitude to allow for the positions taken by the operating companies and EIA.

Proved Reserves of Natural Gas: Proved reserves of natural gas as of December 31 of the report year are the estimated quantities which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

...It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved.

To quote BP America in its annual shareholder report for 1987, "This reserve revision is not the result of a technical reevaluation, rather, it is because the production of Alaskan gas is contingent upon the construction of transportation facilities or development of other marketing alternatives" [27].

EIA remains in agreement with the companies involved that the eventual production of all the natural gas reserves on the Alaskan North Slope is contingent upon construction of transportation facilities or development of other marketing alternatives except for natural gas used in local operations and miscellaneous sales. There are significant economic uncertainties concerning this gas. However, given the current economic production of North Slope gas, EIA chose to retain it as proved reserves.

The primary reason for the position of including these reserves taken by EIA is definitional; however, EIA also believes that the natural gas in question will be marketed sometime in the future. The EIA will continue to carefully review the status of North Slope natural gas reserves, annually.

Natural Gas Reserves in Nonproducing Reservoirs

Like crude oil, not all proved reserves of natural gas were contained in reservoirs that were producing. Reserves in nonproducing reservoirs are defined as those in reservoirs that did not have production during the entire final quarter of 1987. Proved natural gas reserves, wet after lease separation, of 30,897 billion cubic feet were reported in nonproducing reservoirs as shown in Table 12. This was a decrease of 5.8 percent from 1986. Of these reserves, approximately 45.4 percent were located in the Gulf of Mexico Federal Offshore. These proved reserves were reported by Category I and II operators only. These two categories of operators accounted for about 91 percent of the estimated total natural gas production, wet after lease separation. The reasons for the nonproducing status of these proved reserves have not been collected by EIA since 1981. However, previous surveys indicated that most of the wells or reservoirs were not producing for operational reasons. These operational reasons included waiting on workovers, drilling additional development or replacement wells, installing production or pipeline facilities, and awaiting depletion of other zones or reservoirs before recompletion in reservoirs not open to production.

Lease Separator: A lease separator is a facility installed at the surface for the purpose of (a) separating gases from produced crude oil and water at the temperature and pressure conditions of the separator, and/or (b) separating gases from that portion of the produced natural gas stream which liquefies at the temperature and pressure conditions of the separator.

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases which may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with crude oil, and are not distinguishable at the time as separate substances. (See Natural Gas, Natural Gas, Nonassociated and Natural Gas, Associated-Dissolved)

Natural Gas, Associated-Dissolved: The combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Natural Gas, "Dry": The actual or calculated volumes of natural gas which remain after:

1. The liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); and
2. Any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

Natural Gas, Nonassociated: Natural gas not in contact with significant quantities of crude oil in a reservoir.

Natural Gas Liquids: Those hydrocarbons in natural gas which are separated from the gas through the processes of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as condensate, natural gasoline, or liquefied petroleum gases. Where hydrocarbon components lighter than propane are recovered as liquids, these components are included with natural gas liquids.

Natural Gas Processing Plant: A facility designed to recover natural gas liquids from a stream of natural gas which may or may not have passed through lease separators and/or field separation facilities. Another function of the facility is to control the quality of the processed natural gas stream. Cycling plants are considered natural gas processing plants.

Natural Gas, Wet After Lease Separation: The volume of natural gas remaining after removal of lease condensate in lease and/or field separation facilities, if any, and after exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Natural gas liquids may be recovered from volumes of natural gas, wet after lease separation, at natural gas processing plants. (See Lease Condensate, Lease Separator, and Field Separation Facility)

Net Adjustments: The quantity which preserves an exact annual reserves balance within each State or State subdivision of the following form:

Published Proved Reserves at End of Previous Report Year
+ Net Adjustments
+ Revision Increases
- Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
- Report Year Production
= Published Proved Reserves at End of Report Year

These net adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations as a result of changes in the operator frame, different random samples or imputations for missing or unreported reserve changes, could contribute to net adjustments.

Net Reserve Additions: Consist of net adjustments, net revisions, extensions to old reservoirs, new reservoir discoveries in old fields, and new field discoveries.

Net Revisions: (See Revisions)

New Field: A field discovered during the report year.

New Field Discoveries: The volumes of proved reserves of crude oil, natural gas and/or natural gas liquids discovered in new fields during the report year.

New Reservoir: A reservoir discovered during the report year.

New Reservoir Discoveries in Old Fields: The volumes of proved reserves of crude oil, natural gas, and/or natural gas liquids discovered during the report year in new reservoir(s) located in old fields.

Nonproducing Reservoirs: Reservoirs in which proved liquid or gaseous hydrocarbon reserves have been identified, but which did not produce during the last 3 months of the report year regardless of the availability and/or operation of production, gathering, or transportation facilities.

Volumes of crude oil placed in underground storage are not to be considered proved reserves.

Reserves of crude oil which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved crude oil reserves do not include the following: (1) oil that may become available from known reservoirs but is reported separately as "indicated additional reserves"; (2) natural gas liquids (including lease condensate); (3) oil, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (4) oil that may occur in undrilled prospects; and (5) oil that may be recovered from oil shales, coal, gilsonite, and other such sources. It is not necessary that production, gathering or transportation facilities be installed or operative for a reservoir to be considered proved.

Proved Reserves of Lease Condensate: Proved reserves of lease condensate as of December 31 of the report year are the volumes of lease condensate expected to be recovered in future years in conjunction with the production of proved reserves of natural gas as of December 31 of the report year, based on the recovery efficiency of lease and/or field separation facilities installed as of December 31 of the report year. (See Lease Condensate and Proved Reserves of Natural Gas).

Proved Reserves of Natural Gas: Proved reserves of natural gas as of December 31 of the report year are the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations.

The area of a gas reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas-oil and/or gas-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.

Volumes of natural gas placed in underground storage are not to be considered proved reserves.

For natural gas, wet after lease separation, an appropriate reduction in the reservoir gas volume has been made to cover the removal of the liquefiable portions of the gas in lease and/or field separation facilities and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

For dry natural gas, an appropriate reduction in the gas volume has been made to cover the removal of the liquefiable portions of the gas in lease and/or field separation facilities, and in natural gas processing plants, and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved. It is to be assumed that compression will be initiated if and when economically justified.

Proved Reserves of Natural Gas Liquids: Proved reserves of natural gas liquids as of December 31 of the report year are those volumes of natural gas liquids (including lease condensate) demonstrated with reasonable certainty to be separable in the future from proved natural gas reserves, under existing economic and operating conditions.

Report Year: The calendar year to which data reported in this publication pertain.

Reserves: (See Proved Reserves)

Reserves Changes: Positive and negative revisions, extensions, new reservoir discoveries in old fields, and new field discoveries, which occurred during the report year.

Reservoir: A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Revisions: Changes to prior year-end proved reserves estimates, either positive or negative, resulting from new information other than an increase in proved acreage (extension). Revisions include increases of proved reserves associated with the installation of improved recovery techniques or equipment. They also include correction of prior report year arithmetical or clerical errors and adjustments to prior year-end production volumes to the extent that these alter reported prior year reserves estimates.

Royalty (Including Overriding Royalty) Interests: These interests entitle their owner(s) to a share of the mineral production from a property or to a share of the proceeds



William W. Barnwell, Commissioner

STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

3001 PORCUPINE DRIVE

ANCHORAGE, ALASKA 99501

Steve Cowper, Governor

C. V. Chatterton, Commissioner
Chairman of Commission

Lennie C. Smith, Commissioner



BULLETIN

MAY 1988

ADMINISTRATIVE APPROVAL NO. 145-A.32

Administrative Approval No. 145-A.32 was issued on April 4, 1988 to ARCO Alaska, Inc approving flaring of up to 12.5MMSCF of gas at Flow Station #2, Prudhoe Bay, while making tie-ins to the gas coolers. Flaring is to be held to a minimum, shall be metered, and is subject to AS 43.55.020(e).

ADMINISTRATIVE APPROVAL NO. 145-A.33

Administrative Approval No. 145-A.33 was issued April 22, 1988 to ARCO Alaska, Inc approving flaring of up to 28MMSCF of gas at Flow Station #2, Prudhoe Bay, during repair of common lines from drill sites 3, 9 and 7. Flaring is to be held to a minimum, shall be metered, and is subject to AS 43.55.020(e).

ADMINISTRATIVE APPROVAL NO. 232.1

Administrative Approval No. 232.1 was issued on April 7, 1988 to Standard Alaska Production Company approving exceptions to Conservation Order No. 202, Rule 9(b), for sections 1, 3, 7, 9, 10 and 35 in the Duck Island Unit. Although these sections are currently outside the areal gas cap limit, the approval does not preclude wells drilled in these sections from future use as SOC monitoring wells.

Note: Page 4, only, Attached

ESTIMATE OF GAS RESERVES IN ALASKA

Reserves (BSCF)
January 1, 1988

<u>Non-Associated Gas by Field</u>		<u>Associated Gas by Field</u>		<u>Shut-in Gas by Field</u>	
Beaver Creek	177	Beaver Creek	1	Albert Kalos	**
Beluga River	604	Endicott	907	Birch Hill	11
Cannery Loop (Kenai)	300	Granite Point	15	East Umiat	**
East Barrow	8	Katalla	*	Falls Creek	13
Kenai	463	Kuparuk River	634	Ivan River	26
Lewis River	18	McArthur River	25	Kavik	**
McArthur River	600	Middle Ground Shoal	7	Kerik	**
North Cook Inlet	680	Prudhoe Bay,		Moquawkie	**
Pretty Creek	25	Lisburne Oil Pool	406	Nicolai Creek	3
South Barrow	7	Prudhoe Bay,		North Fork	12
Trading Bay	29	Prudhoe Oil Pool	23,441 ***	Sterling	23
Total	2,911	Redoubt Shoal	*	Stump Lake	**
		Swanson River	250	West Foreland	20
		Trading Bay	2	West Fork	6
		Umiat	*	Total	174
		Unnamed Field Pt. Thompson			
		Unit Area	*		
		Unnamed Field Seal Island Area	*		
		Unnamed Field Colville Delta			
		Area	*		
		Total	25,688		

One major addition to Alaskan gas reserves was realized in 1987. The Cannery Loop Unit was under development and slated for 1988 production. Alaskan gas reserves stands at approximately 29 trillion standard cubic feet.

* Insufficient data available for determination of oil reserves in these fields therefore no associated gas reserves may be assigned.

** Reservoir extent as yet undetermined for these reservoirs and lack of operator commitment to produce the gas precludes assignment of reserves.

*** Includes CO₂ at approximately 12% concentration.

STATE OF ALASKA

**HISTORICAL AND PROJECTED
OIL AND GAS CONSUMPTION**

**Steve Cowper
Governor**

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Note: Pages 1-2, 5-7, 11-13, 33-35,
ONLY, ATTACHED

EXECUTIVE SUMMARY

This report compares estimates of the quantity of available Alaskan oil and natural gas reserves with estimates of how much oil (refined products) and gas Alaska will consume in the 15 year period between 1988 and 2002. A revised supply and demand report is issued each year to comply with AS 38.05.183(d), which states:

"(d) Oil or gas taken in kind by the state as its royalty share may not be sold or otherwise disposed of for export from the state until the commissioner determines that the royalty-in-kind oil or gas is surplus to the present and projected intrastate domestic and industrial needs. The commissioner shall make public, in writing, the specific findings and reasons on which his determination is based and shall, within 10 days of the convening of a regular session of the legislature, submit a report showing the immediate and long-range domestic and industrial needs of the state for oil and gas and an analysis of how these needs are to be met."

Chapter 1 describes the state's royalty oil program and reviews pending federal legislation which might affect prices of state royalty oil.

Chapter 2 lists high, middle and low estimates of oil and gas reserves, and their respective royalty shares. High estimates assume increasing oil prices and additional enhanced oil recovery efforts, whereas middle and low estimates assume relatively stable oil prices. The lower figures, therefore, are prudent values for long range policy considerations. The middle range oil estimate is 6.8 billion barrels of oil, yielding an 850 million barrel state royalty share. Of this royalty share, 99.0% is attributable to reserves on the North Slope. The middle range estimate of gas is 32.1 trillion cubic feet. The state's share is 3.9 trillion cubic feet. Again, 90.9% of the gas will come from North Slope reserves.

The chapter includes production estimates for a 25 year period. North Slope oil production has peaked at about 2.3 million barrels per day and is expected to begin declining in the next year or two to about 435 thousand barrels per day by the year 2003.

Chapter 3 presents historical data on production and consumption of Alaska oil and gas. Fuel consumption between 1977 and 1988 grew by an average of 9.5% per year from 0.7 to 2.0 billion gallons, while gas consumption in the same period grew an average of 7.5% per year from 205 to 388 billion cubic feet.

Chapter 4 reveals forecasts of expected in-state oil and gas consumption from 1989 to 2003. Alaska will probably consume about 24 billion gallons of fuels and 3.9 trillion cubic feet of gas during that period. Consumption growth rates are forecast to be considerably lower than they have been until now; and between 1989 and 2003, estimated annual growth in consumption will be 1% for both oil and gas.

Chapter 5 compares estimates of state reserves and future production with estimates of future consumption. The comparison shows that Alaska's total supply of oil and gas will be greater than in-state consumption for the next 15 years.

The supply and demand projections in this report are accurate only if their underlying assumptions approximate future events. The demand side of the equation is probabilistic because in-state consumption will be influenced by economic and population growth which in turn will be influenced in a large part by world energy and natural resource prices. For example, development of a new southcentral hydroelectric project (other than Bradley Lake) or a coal-fired electric generation project could dramatically affect the in-state demand for natural gas, particularly after the late 1990s. Future expansion of the natural gas, ammonia-urea or petrochemical export market would similarly affect in-state natural gas availability, as well as prices.

The supply side of the equation is also probabilistic. The middle range estimates of oil and gas reserves, 6.8 billion barrels and 32.1 trillion cubic feet, respectively, are likely outcomes, though the timing of a gas pipeline from the North Slope remains very uncertain and the development of certain proven oil and gas fields beyond the Prudhoe Bay - Kuparuk infrastructure appears unfeasible at today's oil prices. Estimates of undiscovered resources are highly speculative and are not relevant to this projection. Even if these undiscovered resources exist (which they may not), there is no guarantee that they will be discovered or developed in time (or if ever) to assure long-run continuity. For the most part, major oil and gas firms will search for and develop reserves in response to world market conditions, not because of surplus or deficit conditions in Alaska's relatively small intrastate market. In summary,

1 See Appendix D for discussion of statutory definitions.

reasonable assumptions about Alaska's existing oil and gas reserves and future consumption indicate that not only are current reserves more than adequate to meet the demands of Alaskans for the next 15 years, but that significant quantities are surplus to requirements and therefore are available for export from the state.

CHAPTER 2

RESERVE ESTIMATES AND ROYALTY SHARE

Introduction

This chapter discusses estimates of oil and gas reserves in the state and the state's royalty share of these reserves. The reserve estimates have been developed for three different cases. The specific royalty terms of individual oil and gas lease contracts were used to calculate the state's royalty share of the respective reserves in each field. The low range estimates assume falling oil and gas prices and/or poorer-than-predicted reservoir performance. The high range estimates assume rising oil and gas prices and/or better-than-predicted reservoir performance. The middle range estimates assume relatively stable oil and gas prices and predicted reservoir performance.

The estimated reserves and royalty share for oil and gas are shown in Table 2.1. The estimates have been developed separately for Cook Inlet and the North Slope, as different information sources were used for each category. In addition to categorizing reserves by region, reserves are sub-categorized as either "proven and developed" or "proven but undeveloped or shut-in." These sub-categories distinguish those volumes of oil and gas which are readily marketable from those which need additional investment in facilities and transportation systems which will delay bringing the reserves on line.

Oil reserves as of January 1, 1989 are 6.80 billion barrels. For comparison, the U. S. Department of Energy estimate for January 1, 1988 was 7.38 billion barrels; the Table 2.1 figure extrapolated back to January 1, 1988 is 7.45 billion barrels.

Cook Inlet

Considerable historical and subsurface information is available about the oil and gas reserves and potential in the Cook Inlet area. While there has been a renewed interest in Cook Inlet exploration and remedial field work, it is not anticipated that significant new reserves will be added in the near future. Recent changes in working interest ownership of several Cook Inlet gas fields will likely result in development of these currently shut-in fields. The reserves are assumed to remain constant for low, middle and high range estimates. Cook Inlet reserves account for about 1.8% of the low, 1.2% of the middle, and 0.8% of

the high estimates of statewide total oil and gas reserves.

North Slope

Oil and gas reserve estimates shown in Table 2.1 are for currently leased state lands. North Slope oil is produced from the Sadlerochit and the Lisburne reservoirs in the Prudhoe Bay Unit, the Kuparuk River reservoir in the Kuparuk River Unit, and the Endicott reservoir in the Duck Island Unit. Production from the Kuparuk River reservoir in the Milne Point Unit was shut-in January 1987 and remains shut-in.

Additional enhanced oil recovery operations at Prudhoe Bay Unit, over and above those already planned, recovery of additional gas condensate and gas liquids from the Sadlerochit and Lisburne gas caps and enhanced oil recovery from the Kuparuk and Lisburne reservoirs represent an oil resource (versus oil reserves) of about two billion additional barrels of liquids which may or may not be economically recoverable sometime in the future. The economics of enhanced oil recovery operations are extremely sensitive to incremental capital costs, changing markets and expected wellhead crude oil prices. Systematic recovery of liquids from the Sadlerochit and Lisburne gas caps (and absent major gas sales, simultaneous reinjection of the dry gas back into the reservoirs) would require additional investment by the respective gas cap owners. Depending on the nature of the liquids recovered and intended for sale, the owners of the Trans-Alaska Pipeline System (TAPS) may also have to invest in additional infrastructure, as well as retrofit existing pipeline, storage and shipping facilities to ship these gas liquids. In the fall of 1988, the three major gas owners in the Prudhoe Bay Unit (ARCO, Exxon and BP America) announced that a major new gas project they were reviewing (called "Super Spike") did not appear to be economically feasible at that time.

Installation of the world's largest central gas facility at Prudhoe Bay in 1986 is designed to recover gas liquids and gas condensate from the produced gas stream and it is a major step in establishing the infrastructure that will be needed to proceed with any future large-scale gas sales or expanded gas cycling or liquid recovery project.

TABLE 2.1

[1] As of 1/1/89. Alaska Oil and Gas Conservation Commission, "Estimate of Oil Reserves in Alaska" and "Estimate of Gas Reserves in Alaska", adjusted for 1988 production.

The currently configured plant will recover propane, butane and heavier hydrocarbon liquids from the produced gas stream and it could be modified to recover ethane. Significant volumes of these three products could be shipped through TAPS if the pipeline system and the storage and loading facilities at Valdez were modified. However, until a long term market can be identified for some or all of these three products, no major new gas liquids project will go forward.

The possibility for conversion of any of the above mentioned resources to the proven reserves category and the timing of that conversion must be viewed with extreme caution at this time. However, because billions of barrels of oil will remain in the ground at the Prudhoe Bay and Kuparuk River Units after completion of primary and secondary oil recovery operations, sufficient economic incentives to develop additional economic means of enhanced oil recovery will exist well into the future. For instance, in the Prudhoe Bay Unit Sadlerochit Reservoir, some 12 billion barrels of oil will remain in place if the current ultimate recovery estimate of 10.8 billion barrels holds true. The original ultimate recovery estimate of 9.6 billion barrels has slowly increased to the current 10.8 billion barrel level - hopefully, new enhanced oil recovery technologies, increased infill drilling and horizontal drilling advances can increase the 10.8 billion barrel figure even further. New techniques of using the gas liquids in the reservoir gas caps could also add significantly to the ultimate recovery figure.

Various North Slope leaseholders continue to experiment with techniques to economically produce the vast amounts of "heavy," low gravity oil held in the shallow Tertiary and Cretaceous age sands primarily located west of Prudhoe Bay field. Technology and equipment already exist to produce these types of oil deposits in more temperate, less costly operating and marketing climates. However, permafrost considerations, surface-related permitting, construction and operating constraints, and the projected wellhead price of the produced oil to date have combined to stymie any commercial development of these relatively shallow (but very large) resources. One major pilot production project has been completed by ARCO in the Kuparuk River Unit and laboratory research continues in an effort to improve project performance and economics. ARCO has applied for permits to conduct a second major "West Sak" pilot production project

in the Kuparuk River Unit. A larger well spacing pattern will be used relative to the first pilot and various well bore completion techniques will again be tested in an attempt to improve individual oil well production rates. A water flood will also be conducted to test the influence of the wider well spacing on oil recovery and well performance.

Conoco has received approval to drill two test wells in Milne Point Unit to test the extensive shallow oil sands in that unit. Conoco has also applied to continue the suspension of production at Milne Point Unit through 1989. Shut-in production in Milne Point Unit comes from the deeper Kuparuk Formation.

Technology exists to produce in the range of 300,000 bpd of oil from the shallow north slope oil sands, but current economics do not appear to favor full-scale development. In the Kuparuk River Unit, the Kuparuk River reservoir owners and the West Sak reservoir owners need to approve a facilities-sharing agreement because it will greatly reduce the future West Sak development costs. As Kuparuk oil production facilities become underused and available in the 1990s, it is anticipated that the West Sak reservoir can be brought on line to fill them. Development of the West Sak reserves will also require drilling many hundreds of additional wells and the construction of many more drillsites and pipelines. If and when Milne Point Unit resumes production, the unit's two groups of owners might share facilities in a similar way.

Tables 2.2 and 2.3 list production forecasts for some of the fields listed in Table 2.1. Figure 2.1 graphically portrays these estimates. North Slope oil production is expected to decline in 1989. The decline will begin earlier and will be more gradual than earlier forecasts indicated. Oil production from state-owned lands will decline through the 1990s.

Currently, natural gas is not exported from the North Slope. Both the Alaska Natural Gas Transportation System (ANGTS) and the Trans-Alaska Gasline System (TAGS) are proposed means of moving North Slope gas to market. To date, neither project has secured financing or a guaranteed market. The continued volatility and uncertainty in prices for oil and gas, the relatively abundant worldwide supplies of natural gas, and the sheer magnitude and cost of the proposed pipeline projects combine to make the prospective purchasers of the gas, the financial institu-

tions, and the projects' sponsors all very cautious at this time. Efforts to secure markets for the gas are continuing. However, start up of the ANGTS or TAGS project cannot be expected until financing for one or both projects is arranged, and financing likely will not be finalized until long-term sales agreements for the gas are guaranteed. In addition, the owners of the gas (primarily ARCO, Exxon and BP America) have not agreed to sell the gas to either pipeline company or any of the potential end users. In addition, pending legislation in Congress which would open ANWR to exploration and development would prohibit the construction of pipelines eastward through designated wilderness areas adjacent to the U. S. - Canada border.

During 1988 Esso Resources Canada and Shell Canada applied to the Canadian National Energy Board for permission to export gas from the Canadian Beaufort Sea and MacKenzie River Delta to the United States. This project, while it would be in direct competition with Alaskan North Slope gas for potential U. S. markets, might be an incentive to re-evaluate the once-proposed gas line from Prudhoe Bay east across the Arctic National Wildlife Refuge to the Canadian MacKenzie River Delta area. Such a pipeline probably would be much cheaper to build than either ANGTS or TAGS. At this time no estimates of transportation costs are available for this type of proposal.

Several noteworthy oil and gas related events occurred in 1988. Production at the Milne Point Unit remained suspended. All the facilities have been left in place so that production can be restarted. Conoco, the unit operator, stated that oil prices were not high enough in 1988 to resume day-to-day operations. Conoco also stated that oil prices must be in the 18 to 22 dollar per barrel range for Milne Point field to produce at a profit. On the brighter side, the Endicott field (Duck Island Unit) in the Beaufort Sea completed its first year of operation. Rates are expected to average 100,000 bpd through 1991, then decline.

During 1988 the 8,000th tanker load of oil was shipped from Valdez terminal. Over 6 billion barrels of oil have been shipped from Valdez since 1977.

Standard Alaska Production Company proposes to develop the Niakuk reservoir, located about one mile offshore in the Beaufort Sea just north of Prudhoe Bay. Standard estimates that the reser-

voir could produce up to 20,000 bpd of oil beginning in 1992 if development plans are approved in a timely manner. The proposal includes a 6,600 foot ground fill causeway which state and federal agencies are now reviewing. The U. S. Army Corps of Engineers has issued a preliminary finding that the causeway is unacceptable as proposed. Standard may have to substantially modify the project to gain approval or the project may not be approved at all.

In early 1988, Alaska became the number one oil producing state in the nation. However, with the recent decline in production at Prudhoe Bay, Texas has again regained the number one producing spot. During October 1988, Texas and Alaska averaged 2.065 and 2.000 million barrels per day of oil, respectively. Alaska continues to supply almost 25 percent of the nation's domestic oil supply. Figure 2.2 compares Alaska's oil production with that of other major oil producing countries. Figure 2.3 compares Alaska's projected oil production with that of the lower 48 states. In February Kuparuk River Field set an in-field production record of 322,000 bpd. Field average for 1988 probably will be 280,000 bpd.

The current 1.45 million bpd crude oil production rate at Prudhoe Bay (an additional 0.1 million bpd of gas condensate and liquids are also produced) is expected to continue its slow decline in 1989. The actual rate of the decline will be influenced by the level of infill development drilling, rate of development of the West End and P Pad areas of the field, scheduling of well workovers and equipment repairs, water and miscible gas injection rates, and the capabilities of the installed and to-be-installed gas handling facilities. The Prudhoe Bay owners have approved the construction of GHX-1, a major new gas handling expansion project. The project is designed to boost the amount of gas that can be produced, handled and reinjected from about 3.5 billion cubic feet per day to just over 5 billion cubic feet per day. Bottlenecks in gas processing facilities and insufficient gas compressor capacity are causing a gas overload in the field production facilities. Oil production rates are being cut back because the gas processing facilities cannot handle all the gas associated with the higher oil rates. The oil production rate in 1989 is not expected to reach the allowed annual average 1.5 million barrels per day. Start up of the GHX-1 facilities in the fall of 1990 will alleviate some of the gas overload. The producers are already studying a second project,

GHX-2, which would be designed to boost the gas handling capacity in the field to about 7.5 billion cubic feet per day.

Start-up of the GHX-1 project (and the potential for the GHX-2 project) will help slow the decline of oil production at Prudhoe Bay. If additional gas handling facilities are not installed, the decline will be much more rapid than currently anticipated. In relative terms, more and more gas will be produced along with each barrel of oil as oil production continues over the years. If this additional gas cannot be processed and reinjected, the oil production rate will have to be cut back even further.

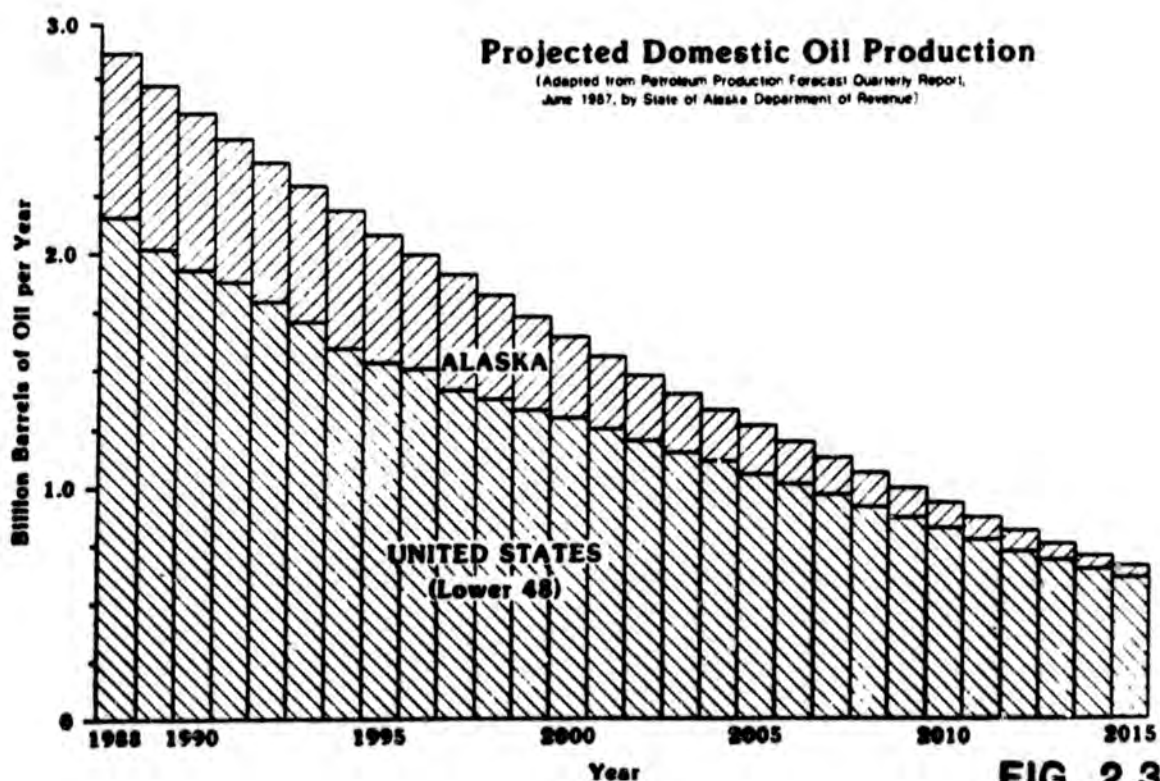


FIG. 2.3

CHAPTER 3

HISTORICAL OIL AND GAS PRODUCTION AND CONSUMPTION

Oil Production

All Alaska oil is produced from Cook Inlet and the North Slope. Cook Inlet fields began production in the late 1950s and peaked by 1970; some of the fields are now near depletion. The region has produced a cumulative total of 1.1 billion barrels of crude oil, but for the last ten years, annual production has fallen from 56 million barrels in 1977 to 16 million barrels in 1988. Prudhoe Bay began commercial production when the Trans-Alaska Pipeline System (TAPS) opened in 1977. Since then the region has produced 6.6 billion barrels of crude oil. Production from this region is expected to peak in 1988 at 706 million barrels per year. Regional and state production data are presented in Table 3.1 and Figure 3.1.

Oil Consumption

All the oil consumed in Alaska is consumed as refined fuels, some of which is refined in-state and some of which is imported. Though no data source satisfactorily reports how much fuel is refined in state nor how much is imported, Department of Revenue (DOR) reports of fuel sales for 1977 to 1988 indicate how much fuel is consumed in state. Data quality from 1977 to about 1984 are unconfirmed, but data from 1985 to 1988 are considered good. Throughout the 11 year reporting period, consumption goes from 750 million gallons per year to 1,961 million gallons per year. Fuel sale data are reported in Table 3.2 and Figure 3.2.

Gas Production

As with oil production, virtually all of Alaska's natural gas is produced from Cook Inlet and the North Slope immediately adjacent to the Prudhoe Bay Unit complex. Production from two small gas fields near Barrow is the only exception. Cook Inlet produces both casinghead and dry gas from a mix of oil fields, gas fields and oil fields with gas caps. Gas production from this region began in the late 1950s and peaked between 1982 and 1984. Cumulative production is 3.4 trillion cubic feet, net of injection, including the 191 billion cubic feet produced in 1988.

North Slope gas production is a by-product of oil field development. The only market for the gas is as fuel for field and pipeline operations and consequently, operators inject 80% of the gas back

into the reservoirs. A cumulative 1 trillion cubic feet, net of injection, have been produced, including 209 billion cubic feet produced in 1988. Table 3.3 and Figure 3.3 show state and regional gas production from 1971 to 1988.

Gas Consumption

The Cook Inlet region's major natural gas feature is its pipeline connections to local markets which this past year consumed 171 billion cubic feet, net of injection. The major users were: LNG, 31% of net production; ammonia-urea production, 20%; electricity generation, 19%; and gas utilities, 13%. An additional 20 Bcf were consumed in field operations.

In contrast to the Cook Inlet region, the North Slope region produces an immense amount of casinghead gas but, as mentioned above, the only market for this gas is as fuel for the oil production facilities. Field operations consumed most of the 1988 net North Slope production (150 billion cubic feet) and an additional 18 billion cubic feet were sold to TAPS. Table 3.4 and Figure 3.4 show state and regional gas consumption data from 1971 to 1987. It is interesting to note that, in 1987 and 1988, field operations alone in the Prudhoe Bay region consumed more gas than total commercial use in Cook Inlet.

APPENDIX C

DEFINITIONS OF STATUTORY TERMS

AS 38.05.183 states that oil and gas taken in-kind as the state's royalty share of production may not be sold or otherwise disposed of for export from the state until the Commissioner of Natural Resources determines that the royalty-in-kind oil or gas is surplus to the present and projected intrastate domestic and industrial needs for oil and gas.

The statute contains several key terms whose meaning must be resolved before an estimate can be made of oil and gas surplus to the state's needs. These key terms are: 1) "oil and gas," 2) "export," 3) "present," 4) "projected," 5) "domestic," 6) "industrial," 7) "intrastate," and 8) "how these needs are to be met." Each key term affects the size of the estimated demand for oil and gas in Alaska and consequently, the size of the projected surplus or deficit. The meaning of each term is discussed below.

"OIL AND GAS"

Crude oil and natural gas are fluids containing hydrocarbon compounds produced from naturally occurring petroleum deposits. Typical crude oil contains several hundred chemical compounds. The lightest of these are gases at normal temperatures and pressure, described as "natural gas." These light fractions of the crude oil stream include both hydrocarbon and non-hydrocarbon gases, such as water, carbon dioxide, hydrogen sulfide, helium, or nitrogen. The principal hydrocarbons are methane (CH₄), ethane (C₂H₆), propane (C₃H₈), butanes (C₄H₁₀), and pentanes (C₅H₁₂). The gaseous component found most often and in largest volumes is, typically, methane. Heavier fractions of the crude stream are usually liquids. If a given hydrocarbon fraction is gaseous at reservoir temperatures and pressures, but is recoverable by condensation (cooling and pressure reduction), absorption, or other means, it is classified by the American Gas Association (AGA) as a natural gas liquid (NGL)². Natural gas liquids include ethane if ethane is recovered from the gas stream as a liquid. A related term is liquefied petroleum gas (LPG), composed of hydrocarbons which liquefy under moderate pressure under normal tempera-

tures. LPG usually refers to propane and butane. A second related term is condensate, which refers to LPG plus heavier NGL component (natural gasoline). The lightest hydrocarbon fraction is methane, which is almost never recovered as a liquid, and which makes up the bulk of pipeline gas. If a natural gas stream contains few hydrocarbons which are commercially recoverable as liquids, it is considered "dry gas" or "lean gas." The distinction between "wet" and "dry" is usually a legal one, which varies from state to state. "Crude oil" usually means the non-gaseous portion of the crude oil stream.

Natural gas may occur in reservoirs which are predominately gas-bearing or in reservoirs in which the gas is in contact with petroleum liquids. Non-associated gas is natural gas from a reservoir where the gas is neither in contact with nor dissolved in crude oil. Associated gas occurs in contact with crude oil, but is not dissolved in it. A gas cap on a crude oil reservoir is a typical example of associated gas. Dissolved gas is dissolved in petroleum liquids and is produced along with them. Dissolved and associated gases are usually good sources of NGL while non-associated gases are often "dry."

The distinction between natural gas and its NGL components is important to a study of the supply and demand of royalty oil and gas because natural gas liquids have a multitude of uses when separated from the gas stream. For example, propane is both produced in Alaska and sold in Alaska as bottled gas for residential, commercial, and limited transportation uses, while butane is used for blending in gasoline and military jet fuel and as a refinery fuel. In addition, Marathon Oil uses LPG to enrich crude oil at its Trading Bay facility. It ships the combined fluids to the Drift River terminal for export³. Potential uses for NGL also include the enriching ("spiking") of pipeline gas and crop drying. Several years ago the Dow-Shell Petrochemical Group and Exxon studied the feasibility of utilizing the NGL contained in Prudhoe Bay natural gas as the basis for an Alaska petrochemicals industry. Since the state has the option of considering NGL separate-

2 Definitions vary with process.

3 Kramer, L., Williams, B., Erickson, G., In-State Use Study for Propane and Butane. Prepared for the Department of Natural Resources by Kramer Associates, Juneau, October 1981.

ly from the gas stream, two definitions of natural gas consumption and reserves are possible. One of these would consider natural gas liquids as part of the gas stream. The second definition would treat the markets for LPG and ethane separately from those for gas. This requires a separate estimate of LPG consumption and gas liquids reserves. In this report, demand for LPG and ethane is estimated separately from that for gas; however, no separate estimate is made of gas liquids reserves.

"EXPORT"

Taken in context, this term appears to mean the direct physical shipment of oil and gas out of the state. However, when one considers the fact that much of Alaska's industrial use of oil and gas is processed directly for export markets, the meaning of export versus "intrastate" is not so obvious. For example, it appears that processing of gas into another product, e.g., anhydrous ammonia, would probably be an "industrial" use rather than "export" of gas, even though the ammonia is mostly exported. Liquefaction to change the phase of the gas is a less obvious case. The liquefaction of natural gas is considered a transportation process in this report. Still more troublesome is the use of gas and oil for transportation related to export. Is the gas and oil consumed in TAPS pipeline pump stations, for example, an "industrial" use in state? Or is it really "export" of that energy, since it is consumed in the exporting process? There is no reason why the state may not be approached in the future to commit royalty oil and gas to quasi-export uses. Indeed, ALPETCO (later, Alaska Oil Company) made a top dollar offer for royalty oil ultimately destined (as petrochemical products) for out-of-state markets. Though they made the offer, they did not make payments in full. Also, the state once committed royalty gas to the El Paso gas pipeline proposal for export of Prudhoe Bay gas, which involved liquefaction. Neither proposal was clearly for in-state industrial use. In this report, industrial demand is treated with multiple definitions as outlined later in the chapter to show how different definitions of "export" affect the estimate of total consumption in Alaska.

"PRESENT"

The problem here is that the term "present" may mean "latest year" consumption, "average recent year" consumption, "weather-adjusted" consumption, or "worst case" consumption. In the residential and commercial sector particularly, each

definition gives a somewhat different answer because of the variability of weather.

The "worst case" consumption calculation can result in considerably higher gas consumption than the most recent year, if the most recent year happens to have been a relatively warm one. While it is not correct forecasting procedure to make long run forecasts of intrastate residential consumption of natural gas which assume worst case forecasts for every year, it may be prudent in practice to reserve part of the the State's gas and oil supply for bad weather. For forecasting, variability of weather makes the picking of a starting value for consumption somewhat tricky. In this report, Rail Belt consumption is based on average weather years. For the remainder of the state, trended per capita consumption is used, which approximates average weather conditions.

"PROJECTED"

This is a very difficult concept, since many different projections of consumption would be possible even if it were possible to agree on a single concept defining consumption. Rates of economic development, population growth, and relative energy prices are key features of any consumption forecast, but assumptions concerning any of these variables are necessarily controversial. This report describes a range of possible consumption figures under precisely articulated definitions of consumption and varying paces of economic, population, and fuel price growth.

"DOMESTIC"

Domestic consumption appears to mean Alaska residential consumption. As we saw above under the subheading "present", it is not at all obvious which definition of domestic consumption is the most appropriate, even when the identity of the customer is not in dispute. Some multifamily residential use may be described as "commercial", obscuring the definition of the customer and causing forecasting problems for natural gas. The definition of "domestic" considered in this report includes multifamily residential in "residential" or "domestic" use.

"INDUSTRIAL"

As described above, "industrial" energy use has a number of potential definitions. Since one intent of giving in-state industrial needs priority over export uses of royalty oil and gas seems to be encourage in-state economic activity,⁴ a day-to-day working definition of this industrial priority is

⁴ However, see the short discussion of legislative intent beginning on page 9 of Kramer, Williams and Erickson, op.cit. That study raises many of the issues regarding surplus gas and oil discussed in this report.

that the royalty reserves be committed to the market which has the largest potential economic impact in Alaska. For forecasting purposes, however, it is difficult to say which markets will prove to be of the most economic benefit to the state. As a compromise, we will adopt four alternative definitions of "industrial" in this study.

The four alternative definitions of industrial use of oil and gas used in this report are outlined below, beginning with the most restrictive and moving to the most liberal.

DEFINITION 1: Industrial use consists of any consumption of natural gas, petroleum, or their products in combustion (except that required to export oil or gas); or the chemical transformation of natural gas, petroleum, or their products into refined products for local markets. This definition explicitly excludes the exported products from refineries, as well as uses which merely change the physical form of the product (gas conditioning or liquefaction) for export, or which move the product to an export market (pipeline fuel, fuel used on lease, shrinkage, injection, vented and flared gas).

DEFINITION 2: Industrial use consists of any consumption of natural gas, petroleum, or their products in combustion (except in oil and gas production and transportation); or the chemical transformation of natural gas, petroleum, or their products into refined products. This definition counts feedstocks for petrochemical plants and refineries as industrial consumption. It also counts energy consumed by an LNG facility as industrial consumption. It excludes the feedstocks of LNG plants; and fuel consumption by conditioning plants, pump stations, fuel used on lease, shrinkage, injection and flared gas.

DEFINITION 3: Industrial use consists of any consumption of natural gas, crude oil, or their products in combustion (except in oil and gas transport and extraction) or their chemical transformation into refined products. This definition permits the feedstocks of refineries to be counted as industrial consumption. It excludes fuels used in pump stations, in conditioning plants, fuel used on lease, and gas shrinkage, injection, or venting.

DEFINITION 4: Industrial use consists of any use of natural gas, crude oil, or their products in combustion, or their transformation into chemically different products. This definition permits feedstocks of refineries to be counted as industrial

consumption, as well as energy consumption in conditioning plants and pump stations. It excludes injected gas, which is ultimately recoverable for other uses, and LNG processing, which is considered an export. Definition 4 will be used for the purposes of this report.

None of the four definitions treats industrial use (including transportation) to include gas injected to enhance oil recovery, since in theory this gas remains part of the ultimately recoverable gas reserves of the state. Thus, it is not "consumed."

"INTRASTATE"

It is unclear what is meant by intrastate consumption. Some uses, such as combustion of oil and gas products in fixed capital facilities in Alaska, are reasonably easy to categorize as intrastate. There are several uses in transportation which are not obviously within Alaska. These categories include the fuel burned in marine vessels such as cargo vessels, ferries, and fishing boats, and fuel burned in international interstate air travel. There are multiple ways to approach the definition of this consumption. The first is a sales definition: the fuel used in transportation which is sold in Alaska. The second approach is to base consumption on fuel used in Alaska or related to Alaska's economy and population, regardless of the point of sale. This results in three logical definitions, described below:

DEFINITION 1: Intrastate consumption in transportation includes all sales of fuels to motor vehicles, airplanes, and vessels in Alaska, including bonded fuels. It excludes fuel consumed by motor vessels which was purchased in other states, and fuel consumed by airlines between Alaska locations unless the fuel was sold in Alaska. It also excludes out of state military fuel purchases.

DEFINITION 2: Intrastate consumption includes fuel consumed by motor vessels, airlines, and vehicles engaged in Alaskan economic activity. It includes use of fuel by American fishing boats in Alaskan waters regardless of where the fuel was purchased, use of fuel purchased in Washington State by Alaska State ferries, and fuel consumed by ships and aircraft involved in Alaska trade. It excludes sales to aircraft on international flights (bonded and unbonded), but includes military out of state purchases.

DEFINITION 3: The final definition is a compromise between the first two. It includes all fuel purchased within the state, plus military uses, but

DRAFT

1/10/89

1988 GRI Baseline Projection of U.S. Energy
Supply and Demand to 2010

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December 1988

Foreword

This report summarizes the 1988 GRI Baseline Projection of U.S. Energy Supply and Demand, which has been adopted as a major input to the planning cycle leading to the development of Gas Research Institute's (GRI) 1990 research and development program. The baseline projection represents the GRI planning outlook for the economic and energy supply and demand situation to the year 2010. The 1988 projection was developed independently by GRI using publicly available data and a framework of commercially available models that GRI has modified over several years. It is not derived from the views of GRI member companies.

Strategic planning of GRI's R&D program requires an appreciation of the outlook for national energy supply and demand and an estimate of the role that natural gas will play within that outlook. Another key element in GRI's R&D program planning is an assessment of the benefit that would accrue from the successful development of each individual research project being evaluated for funding. The development of a consistent framework that establishes a likely projection of future energy supply and demand is critical to this assessment process. The framework that forms the scenario and data base for these planning decisions is called the baseline projection. The baseline projection supports the strategic planning of the GRI R&D program--the selection of

• NOTE - Page 98, only,
Attached

significant after 1995. Throughout the entire projection period, resource depletion accounts for about two-thirds of the growth in wellhead prices, and the other factors account for the remainder.

Alaska Natural Gas Via ANGTS

- o The Alaska natural gas transportation system (ANGTS) is assumed to begin operation in 2007 at a throughput of 0.7 quad per year. In 2010, its throughput is expanded to 1.2 quads per year.
- o The fixed price component of ANGTS deliveries is based upon the cost estimates of the pipeline consortium in 1982. Because of competitive pressures, the wellhead price for ANGTS gas is held fixed at \$1.00 per MMBtu (1987\$) until the total price of ANGTS gas delivered to the lower-48 equals the Canadian border price. Thereafter, the wellhead price of ANGTS gas increases as the ANGTS price tracks the Canadian border price.
- o Recently, the principal sponsors of ANGTS have reevaluated the capital costs. This analysis has reduced the capital costs for ANGTS by almost 45 percent. This would mean that ANGTS gas could be competitive with lower-48 wellhead prices in the 1988 GRI Baseline Projection when it is introduced in 2007.

Pipeline Imports

- o Real prices for pipeline imports at the border are set on a competitive basis with lower-48 wellhead prices. Prices vary, however, depending upon the point of competition. If the border export point is a producing region in Canada, then the import price is determined by the marginal wellhead gas price. If the export point is a consuming region, then the import price is determined by the regional citygate

STATEMENT OF JAMES T. JENSEN

IN THE MATTER OF

**YUKON PACIFIC CORPORATION
ERA DOCKET NO. 87-68-LNG**

on behalf of

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION CO.

**JENSEN ASSOCIATES, INC.
Boston, Massachusetts**

PREPARED STATEMENT OF JAMES T. JENSEN
ON BEHALF OF
ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

IN THE MATTER OF
YUKON PACIFIC CORPORATION
ERA DOCKET NO. 87-68-LNG

Public Conference
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Anchorage, Alaska

Prepared by
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JENSEN ASSOCIATES, INC.

Introduction

James T. Jensen, President of Jensen Associates, Inc., an independent energy economics consulting firm, has been asked by Alaskan Northwest Transportation Company to provide an independent judgment on two issues pertinent to the application by Yukon Pacific Corporation (Yukon Pacific) to export Alaskan gas to Japan. These issues are the following:

- (1) Are there sufficient proved and economically transportable gas reserves on the North Slope to warrant construction of two major large-diameter pipeline systems in the same time frame?
- (2) Will the currently proved Prudhoe Bay gas reserves be needed more by the United States or the Pacific Rim countries in the years ahead?

This statement addresses those issues.

Overview Implications of the Yukon Pacific Application for ANGTS

The decision which the Economic Regulatory Administration (ERA) is being called upon to make in this application is without precedent in the U.S. or international gas experience. The decision will inevitably have a major influence on the way in which the pipeline infrastructure ultimately develops for transporting natural gas from Alaska's North Slope to market. The major risk inherent in this decision is that the size and quality of the proved reserves on the North Slope are not adequate to support the construction of two independent transportation infrastructures for Pacific and U.S. gas markets. In such a case the award of this application to Yukon Pacific runs the risk of prejudicing the ultimate construction of a transportation link between North Slope gas and Lower 48 states markets. Further development of the North Slope gas resources could then become dependent on energy market developments in the Asian countries rather than on those in the United States. The public interest implications of ERA's decision in this matter are thus long-term and strategic in nature.

The natural gas industry in the United States is the oldest and most mature gas industry in the world. Most of the pipeline infrastructure on which the transportation of gas from the

producing regions to markets depends was in place by the early 1950's. With the movement to market-responsive pricing and open transportation, gas in the Lower 48 states is approaching commodity status.

From a U.S. gas industry perspective, therefore, it may be difficult at first to recognize that the policy decision we are discussing in this proceeding, in fact, bears far greater resemblance to the decisions which are being addressed today in countries such as Norway or Nigeria, than it does to any gas policy issue that the United States has ever had to face. For Norway and Nigeria, as with many countries throughout the world, proved reserves of natural gas far exceed any foreseeable local market, and the prospect of developing "mega-projects" to export the gas to other markets is under active discussion. Similarly for Prudhoe Bay gas, local markets on the North Slope are virtually non-existent and it requires a "mega-project" to "export" the gas to any reasonably sized consuming region. This includes not only the international markets of the Pacific Rim countries, but also "export" to the Lower 48 states.

There are two very significant differences between the decision we are discussing today and that which other potential gas exporters face. First, the remoteness of Prudhoe Bay from markets and the very high costs of Arctic construction virtually guarantee that any transportation infrastructure will be one of the most expensive private sector energy projects in the world. It thus forces the project to take maximum advantage of economies of scale and minimize the costs of field development, gathering and treatment if it is to have any hope of economic viability. And second, because the infrastructure of the TAGS and ANGTS systems is so different, there is little prospect that the two systems will provide substantial mutual economic support for one another. Norway's North Sea pipeline grid system to the Continent, in contrast, does not foreclose the possibility of future shipments to the U.K. nor does it make it difficult to "piggyback" a U.S.-oriented LNG project onto the grid as Norway has just announced. And Nigeria's proposed LNG liquefaction facility at Bonny similarly does not preclude shipments to either Europe or the U.S.

The requirement that the infrastructure be largely duplicated for both TAGS and ANGTS together with other key issues discussed below, however, may effectively force the ERA to make an either/or choice between the two projects.

Specific Issues in Delivering Alaskan Gas Economically to the Lower 48 States

A critical element of the ANGTS project and presumably also of the TAGS system is the issue of minimizing the costs of transporting Alaska gas from the wellhead to market. In general, there are three areas in which project planners can address this issue. They are by:

- o taking advantage of economies of scale in constructing pipeline facilities to minimize costs;
- o minimizing the costs of finding, developing and gathering gas; and
- o reducing the costs of financing to the lowest extent possible.

In pipelining, economies of scale are a significant factor since substantial savings can be achieved through the use of larger diameter pipe if flows warrant. In effect, capacity increases much more rapidly with increasing diameters than does pipeline investment.

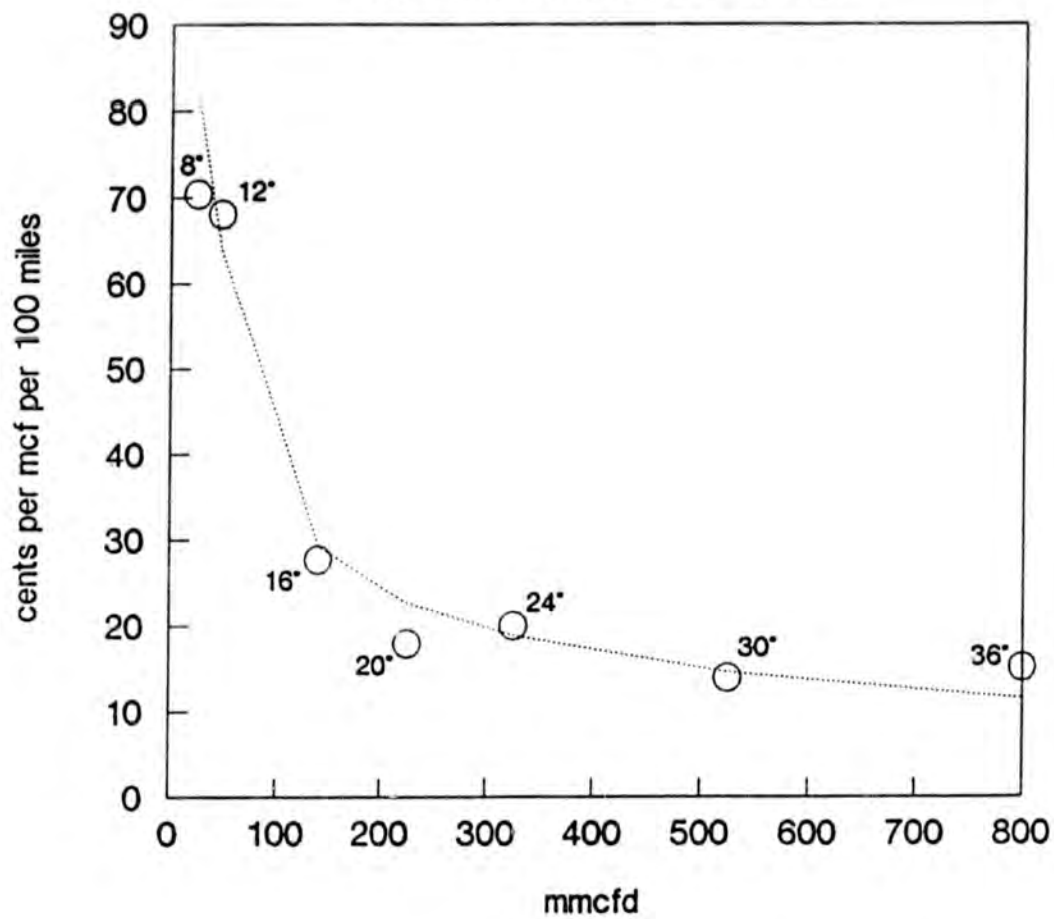
Figure 1 shows the effect of pipeline diameter and thus throughput on the costs of moving gas per 100 miles of pipeline. It is based on onshore pipeline investment costs for 1987 as reported in the Oil and Gas Journal. Alaska pipeline investment costs for Arctic terrain will be much higher. (In order to minimize pipelining costs within Alaska, the ANGTS has resorted to an even larger pipe size with commensurately higher throughputs than is shown in Figure 1.) As a result of its use of a 36 inch pipe diameter pipeline, the TAGS LNG project, at its ultimate design level would be more than twice the size of the largest existing LNG project anywhere in the world.

Issue One: Are there sufficient proved and economically transportable gas reserves for two major pipeline systems in the same time frame?

Because of the size of the ANGTS and TAGS projects, they each require the commitment of very large quantities of proved reserves

FIGURE 1

Cost Of Service As A Function Of
Pipeline Capacity
At 100 % Load Factor



○ Derived From 1987 Costs

if they are to be financeable. The ANGTS project has always assumed that it will require the entire 26 TCF of Prudhoe Bay Sadlerochit reserves if it is to be viable. And even the 16 TCF of reserves which the TAGS project requires represents more than 50% of all reserves remaining on existing contracts from the six countries exporting to Japan, Korea, and Taiwan combined.

This raises the major question as to whether enough relatively low cost, quality proved reserves exist on the North Slope to finance both projects. The final financing will be subjected to very close scrutiny by the lending agencies to assure them that the projects will be economic. This will undoubtedly require both an economic feasibility study with guarantees of wellhead prices in the form of contracts or other binding assurances of gas cost, as well as concrete evidence that there are sufficient proved reserves to guarantee that the pipeline will remain full. For such a feasibility study, vague promises of the potential of discovered but undeveloped reserves or resources will be inadequate. The lending institutions will want to be assured of the costs of the gas as well as its physical availability.

The mining industry uses the term "highgrading" to describe the process of taking out the richest and thus most profitable portion of the ore body first. Basing the development of any gas transportation infrastructure on those reserves which are the least expensive to develop and gather is a form of "highgrading" and will benefit the project which is first able to utilize Prudhoe Bay gas.

It is here that the great concern about the quality of the reserves which will be available after Prudhoe Bay becomes important. Prudhoe Bay is the fifth largest accumulation of natural gas ever discovered in the world outside the Soviet Union and the Middle East. Its reserves are proved in every sense of the word, and much of the costly field facilities which would be required to deliver it to the pipeline inlet are already in place. Gathering lines, some gas compression, and even a portion of the gas processing facilities required to make the gas of pipelineable quality have already been built. The economics of the further gas reserves which would be needed to support a second pipeline are largely unknown. Even the highly regarded Point Thompson gas condensate discovery near Flaxman Island has not been developed sufficiently to warrant inclusion in the proved reserves category of either the U.S. Energy Information Administration or the Alaska Oil and Gas Conservation Commission. Thus the ultimate cost of its gas is largely unknown at this point and could be high.

The experience of several overseas projects and their concern with the development costs associated with particular reserves is instructive. The first example is in Pakistan. The Sui gas field in that country would rank as the world's sixth largest outside the Soviet Union and the Middle East. It has been the basis for the development of the gas industry in that country. The World Bank uses Pakistan to illustrate one of its contentions regarding gas development economics in an Energy Department Paper. In the paper it says of Pakistan:

In Pakistan, the large volumes of gas production and economies of scale in production and transmission lead to low supply costs. The marginal cost for different gas fields are presented in Table (sic) 4. Pakistan has a relatively mature gas industry, and the production to reserve ratio as been increasing. It is now producing from its lower cost fields. As demand increases and supply from these fields fall, the more expensive fields will come under operation.⁽¹⁾

The accompanying Figure 4 is included here as Figure 2.

It is the risk of forcing ANGTS to rely on fields which may be much more expensive to develop than Prudhoe Bay which is the major concern here. Other examples of this sort of concern are readily available.

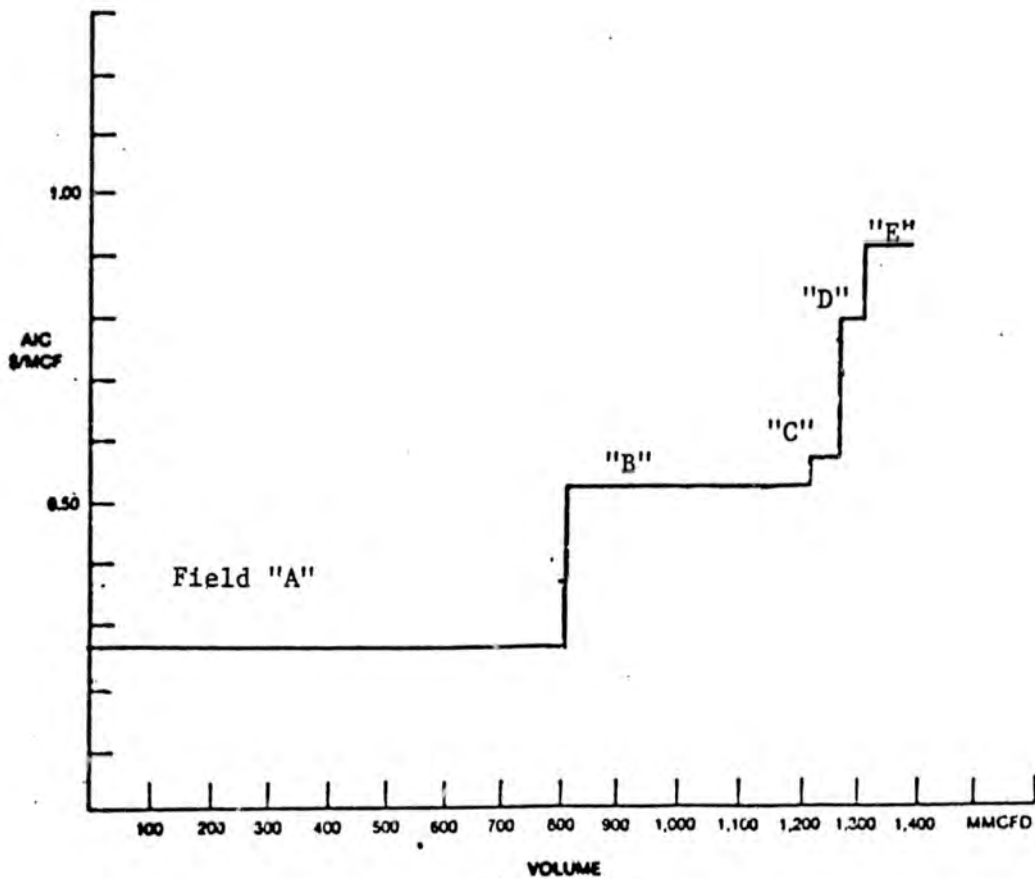
Both Norway and Nigeria are actively exploring new projects to bring LNG to European and/or U. S. markets. In both cases recent press releases have indicated that gas cost minimization has been aggressively pursued to try to make the project feasible.

Norway was widely reported to be trying to develop its northernmost fields in the Troms area of the North Cape for an LNG project. The recent announcement of a contract for U.S. markets indicates instead that they have tried to cut costs by "piggybacking" on the existing Statpipe system out of the Statfjord field farther south. In announcing the contract, R. Gerald Bennett of Enron was reported as saying,

⁽¹⁾ "Marginal Cost of Natural Gas in Developing Countries: Concepts and Applications" Energy Department Paper No. 10, August 1983, The World Bank Energy Department, Washington, DC, pages 15-16.

FIGURE 2

THE AVERAGE COST OF GAS BY FIELD IN PAKISTAN



Source: "Marginal Cost of Natural Gas in Developing Countries: Concepts and Applications" Energy Department Paper No. 10, August 1983, The World Bank Energy Department, Washington, D.C., page 16.

About the economics of the Norwegian LNG, Bennett said the Norwegians are looking at a site next to an existing LNG facility at Karsto, north of Bergen for the liquefaction plant. The supply will come from uncommitted gas reserves in several large North Sea fields and transmission capacity is available in existing pipelines. The Norwegians have already invested a significant amount to develop the gas fields and believe they can add the liquefaction facilities on an incremental cost basis.⁽²⁾

Nigeria, too, in its efforts to minimize costs, has been highly selective of the gas reserves which would be committed to its proposed LNG scheme. An article in the Petroleum Economist describes the process as follows:

These fields [earlier named as Soku, Bomu, Oshi, Idu, Uberta, Obagi, and Ibewa], located just north of the plant site, are all non-associated gasfields, so the costs of compressing associated gas will be avoided. Shell says production costs will be relatively low because the gas is of good quality and because only shallow drilling will be required. The project as envisioned at present will only require some 130 billion cubic meters out of Nigeria's proven and probable reserves - mostly discovered by accident in the course of oil exploration - of 2600 bcm.⁽³⁾

Both economies of scale and "highgrading" will have an important bearing on the costs of financing. If the financial community sees that a future ANGTS project has been modified, eliminating much of the benefits of economies of scale and/or subjected to "highgrading," it is unlikely to readily embrace such a project except at significantly higher financing costs.

⁽²⁾ Natural Gas Intelligence, December 19, 1988, page 1.

⁽³⁾ Petroleum Economist, March 1988, page 92.

Thus, the economic assumptions incorporated into the ANGTS project by itself should not be assumed to be readily transferrable to a modified project that at some future date attempts to make use of North Slope gas reserves other than those in the Prudhoe Bay field.

In summary, there is no evidence that sufficient proved and economically transportable gas reserves on the North Slope exist to warrant construction of two major transportation systems in essentially the same time frame.

Issue Two: Will the currently proved Prudhoe Bay gas reserves be needed more by the United States or the Pacific Rim countries?

The present period in the U.S. gas industry is a particularly difficult time for ERA to make a critical decision regarding the future need for Alaskan gas in the Lower 48 states. The U.S. has experienced a long-term period of gas surplus -- the gas "bubble" or "sausage" as it has been termed for several years. Wellhead spot gas prices have recently been in the \$1.25 - \$1.50 per million cubic feet range. Thus, from the current perspective of the beginning of 1989, the Lower 48 states may not "need" gas whose sponsors quote a tariff of \$3.05 delivered to market.

However, the proposed TAGS start-up date is 1996. By that time, at present rates of gas consumption, the U.S. will have consumed a volume of gas equivalent to 79% of our present Lower 48 proved reserves. By then, whether or not we are in surplus will be dependent on the effectiveness of the industry in exploring and developing our remaining gas resource base, not on current perceptions of the bubble.

There are strong indications that the gas bubble period is ending. Within the industry, gas producers are beginning to reactivate plans for future imports of LNG to the Lower 48 states. Increasingly, U.S. gas consumers are looking to Canada as an incremental source of supply, and Canadian gas imports have been steadily rising. Moreover, an interest in long-term contracting is emerging within domestic gas circles. In effect, there are numerous industry "signals" indicating that the U.S. gas market is tightening and that the period of gas surplus is over.

As gas markets move from surplus to more balanced and perhaps even "tight" gas supply/demand conditions, ERA's decision is

particularly difficult given the uncertainties of gas pricing of the coming years. Wellhead pricing under the surplus conditions of recent years has reflected the abundance of gas relative to domestic demand levels and resulted in gas-to-gas pricing competition. In a more balanced gas environment, however, wellhead pricing will be affected by other factors, such as the world price of oil, the availability and price of other energy sources including coal, the level of Canadian gas exports to the U.S., etc.

In addition, U.S. gas pricing is undergoing a major restructuring because of changes taking place under Federal Energy Regulatory Commission Order Nos. 436 and 500 designed to open up the domestic pipeline network to open-access transportation. At this time, the gas industry is in the midst of a major transition in which historical service obligations and merchant functions of gas pipelines are being shifted to gas distribution companies and even directly to gas users. This fundamental restructuring of pipeline rates is far from complete or settled. Gas markets are and will continue to be affected by developments in transportation rate design, but precisely how is difficult to predict since the mechanisms for implementing the new rate structures are still being formulated. For example, the new gas pricing environment will be characterized by such new rate factors as gas inventory charges, standby reserve charges and other, potentially yet unnamed, factors reflecting the unbundling of gas services historically grouped together in a single gas price. But exactly how these new rate features will affect gas pricing in specific regional markets remains to be seen.

There is little evidence that Asian markets need the Prudhoe Bay gas supply any more than we do at present. Table 1 summarizes the committed or accessible gas reserves available to U.S. and Asian markets. The "accessible" exportable surpluses shown in the table are selected from those countries which are the most obvious trading partners for the market in question. It is apparent from the table that the domestic gas reserves, plus contract commitments, plus market-oriented exportable surpluses, provide for substantially greater coverage for Asian markets than do the comparable reserves for U.S. markets. The total (excluding any North Slope commitments) provides 53.3 years coverage for the Asian market versus 10.1 years for U.S. markets. Addition of the North Slope proved reserves to the Asian market would increase its already substantial coverage of its consumption by nearly 13 years. For the U.S., however, addition of the North Slope proved reserves to its relatively much larger market has a much more modest effect.

From this viewpoint, the U.S. has a much more pressing "need" for North Slope gas than Asian markets.

And while the reserves committed or accessible to Asian markets have been increasing at the rate of 6.4 trillion cubic feet (tcf) per year since 1977, they have been decreasing at the rate of 2.1 tcf per year in the U.S.

In summary, the weight of this evidence is that the proved gas reserves at Prudhoe Bay are much more likely to be needed by the United States in the years ahead than they are by Japan, Korea, and Taiwan.

Should the Yukon Pacific Application Be Denied?

The fundamental issue in this application, in our view, is whether the Yukon Pacific project can go forward as designed without foreclosing important energy options for the U.S. as we approach the turn of the century. If this application is approved, it is possible that just when the TAGS project is under way, the ANGTS option is likely to be an economically attractive, necessary supply source for domestic markets. However, a decision now by ERA may preclude the ANGTS possibility forever, given the potential insufficiency of alternative Alaskan reserves to meet domestic market demands and the deleterious impact the TAGS project may have on the economic viability of ANGTS. Thus, it would appear that the burden of proof that the TAGS project does not preempt the U.S. option should rest with the applicant. Absent credible evidence from Yukon Pacific to the contrary, this application should be denied.

TABLE 1
PROVED RESERVES COMMITTED OR ACCESSIBLE
TO U.S. OR PACIFIC GAS IMPORT MARKETS¹

(Tcf 12/31/86)

	<u>Japan</u>	<u>Korea</u>	<u>Taiwan</u>	<u>Total Pacific</u>	<u>U.S.</u>
Committed to Domestic Markets	1.1	--	0.9	2.0	139.3 ²
Committed on Import Contract ³					
Alaska (Cook Inlet)	0.2	--	--	0.2	--
Abu Dhabi	1.1	--	--	1.1	--
Australia	6.1	--	--	6.1	--
Brunei	1.8	--	--	1.8	--
Indonesia	10.2	2.0	1.5	13.7	--
Malaysia	5.1	--	--	5.1	--
Canada	--	--	--	--	20.1
Mexico	--	--	--	--	<u>1.6</u>
Remaining Contract Volumes	24.5	2.0	1.5	28.0	21.7
Accessible Exportable Surpluses					
Australia				26.8	--
Brunei/Malaysia				31.9	--
Indonesia				15.5	--
Canada ⁴				--	7.7
Mexico ⁵				--	<u>0</u>
Subtotal Surpluses				74.2	7.7
North Slope Proved Reserves					
Yukon Pacific Request				16.0	--
ANGTS Project				--	25.0
Surplus				<u>9.0</u>	--
Subtotal North Slope Proved Reserves				<u>25.0</u>	<u>25.0</u>
Total Above				<u>129.0</u>	<u>193.7</u>
Consumption 1986 (adjusted) ⁶				1.95	16.7
Ratio Accessible Reserves to Consumption					
(ex North Slope)				53.3	10.1
(with North Slope)				66.2	11.6

FOOTNOTE PAGE FOR TABLE 1

- 1 Source of estimates: Based on the supporting detail for Oil and Gas Journal article by James T. Jensen, June 6, 1988, page 38.
- 2 In Jensen Associates, Inc.'s definition, all U.S. domestic proved reserves are "Committed to Domestic Markets" except those expressly allocated to Frontier, Deferred, Committed to Export, or Marginal. North Slope reserves are treated as "Frontier."
- 3 Remaining commitments to end of contract.
- 4 With the abandonment of the surplus test in 1987, Canadian exportable surpluses could rise rapidly reflecting higher depletion rates for proved reserves. This estimate assumes that the Canadian practice of requiring 20-year contracts will be retained and thus the 7.7 tcf is surplus to 20 years of existing contract coverage.
- 5 Mexico ceased exporting to the U.S. in 1984. "Committed to Export" shows volumes remaining on contract. Given current Mexican policy of retaining gas for use at home, exportable surplus is assumed to be zero.
- 6 Total Pacific consumption for 1986 is for Japan and Taiwan. Korea had no consumption at that time; however, Asian volumes have been increased to accommodate new LNG projects starting up between 1986 and 1990.

QUALIFICATIONS OF JENSEN ASSOCIATES, INC.

Jensen Associates, Inc. is a consulting firm specializing in planning and economics for oil and natural gas. We are best known for our experience in North American natural gas markets. Our work in this area covers a broad range of evaluations of demand by sector and by region, supply, pricing considerations, and regulatory and political developments. Some examples of studies we have done for clients will give an idea of the range of our experience.

Retainers

We have a number of retainers with clients in both Canada and the United States with an ongoing interest in North American natural gas markets. They include companies involved in gas distribution, transmission and production, and generally focus on issues of demand, supply, price and regulation.

Market Assessments

JAI was the marketability consultant for the Alaskan Natural Gas Transmission System consortium from 1978 to 1981.

We are called on from time to time to do market studies for major gas supply expansion schemes. Among our studies in recent years are two U.S. East Coast LNG import project evaluations as well as two significant Canadian export pipeline expansion proposals. The feasibility of these projects was dependent upon estimates of market volumes and prices.

International Gas Trade and LNG

JAI has been active in international gas studies, such as LNG developments, for example. We were the contractor for the Office of Technology Assessment of the U.S. Congress on "Imported LNG Projects, Supply and Consumption" -- a policy study undertaken in late 1979. An approach which we used in that study to classify world gas reserves as a basis for international trade was utilized by the IEA in its 1982 study entitled "Natural Gas, Prospects to 2000." We have continued to utilize this approach in papers and speeches since that time. These have included speeches before the Oxford Energy Seminar, the Energy Policy Foundation of Norway and the gas trade summary speeches at the 1984 Gastech Conference in Amsterdam, and the 1986 Conference in Hamburg. The most recent examples of these papers on gas trade are a

paper for the Society of Petroleum Engineers and an article in the Oil and Gas Journal.

Over the past ten years, we have undertaken more than a dozen LNG project studies involving sources in Algeria, Indonesia, Qatar, Norway and Trinidad, and markets in the U.S., Canada, Japan and Taiwan.

We assisted one of the major purchasers of Soviet gas in its anticipated arbitration of its contract with the U.S.S.R. We also undertook a study for one of the major oil companies of the outlook for gas markets in Europe and the influence of Soviet gas export policy on that market.

Supply Evaluations

JAI regularly monitors North American gas supply as a part of our general market monitoring efforts. We were the prime contractors to the Office of Technology Assessment of the U.S. Congress in a study entitled "Understanding Natural Gas Supply in the U.S." Periodically, we undertake specific supply studies for clients. An example of this type of analysis would be a study of the supply position of a pipeline as a means of reassuring an LDC purchaser about the quality of the pipeline's long-term supply position.

Pricing and Contracting

Price forecasts for specific client decisions are frequent assignments for JAI. As examples, we have recently undertaken forecasts of natural gas prices for two different electric utilities, including the logic of price formation as it would influence their operations. Several other recent studies required that we develop escalation clauses that will operate effectively in the new era of market-responsive pricing and volatile energy price formation.

Policy

We are frequently called upon by clients to critique policy proposals by regulatory bodies such as the Federal Energy Regulatory Commission. In Canada, we were selected by the Government's Pipeline Review Panel to assist them in their analysis as to how Canada should move towards open transportation and market-responsive pricing. Our specific assignment was to assist the panel in understanding how the U.S. had approached the problem and what features of the U.S. approach Canada should adopt or avoid.

We were actively involved for Canadian clients in evaluating the alternatives to the earlier Canadian single border pricing policy for exports to the United States. We concluded at an early point that variations on the two-part rate design were a preferred option for Canadian policy. We later assisted several clients in testimony

before the U.S. Federal Energy Regulatory Commission when they sought approval of such a pricing formula for their export contracts.

Strategy/Structure

Some of our projects focus on the question of changing industry structure and the strategy which a company should follow in trying to adapt to change. A major example of such a study was one which we recently undertook for a large interstate pipeline system. The company gas marketing activities had been reorganized upon the recommendation of an organizational consultant. We were asked to provide a second opinion on the organization structure, focusing especially on the likely changes in the market and the organizational effect they would have on demands on company marketing activities. We concluded that certain functions would be required of the company in the future but had not been considered because they were not now part of the present market environment. We recommended changes by which the company could respond to the challenges it would face in the future.

Other

Our experience is both North American and international and includes both oil and gas. We have not included in this listing of projects some of our oil-related work. However, our oil-related work gives us the background to judge oil prices and to determine the interaction between oil market developments and natural gas markets.

JAMES T. JENSEN

Mr. Jensen is President of Jensen Associates, Inc., a firm of consulting energy economists in Boston, Massachusetts. He has a degree in chemical engineering from the Massachusetts Institute of Technology and an MBA from Harvard Business School. For eighteen years prior to his establishment of Jensen Associates, Inc., Mr. Jensen was a Senior Staff Member of Arthur D. Little, Inc. Throughout his career, he has concentrated on petroleum, natural gas, and energy economics and their applications to the management of energy-oriented organizations. His major interests have been in the fields of energy planning, economics, and forecasting, and in investment and feasibility decisions in the energy industries.

He has broad experience in international petroleum and natural gas markets and the impact of governmental intervention on their behavior. His clients have included governments of both producing and consuming countries, as well as private and government energy companies and energy consumers.

Analysis of markets, pricing and interfuel competition have formed a major part of his work. He regularly provides his clients with an interpretation of the political, economic and market forces which determine the prices of oil and gas. Through the use of computer models of interfuel competition which have been developed by Jensen Associates, he frequently provides assessments of the likely impact which energy price changes will have on the relative market share for oil and gas, both by sector and by region. He has undertaken natural gas marketing studies for clients throughout the world and has been responsible for oil marketing strategy studies for companies and for governments.

Issues surrounding energy supply form another important element of his work. These include supply forecasts and long-term crude oil acquisition strategy studies for refiner marketers. He has developed an approach for classifying world gas reserves as a basis for world gas trade which is commonly quoted by others.

Investment feasibility has been an important part of his assignments. These have included refinery expansion projects, transportation facilities, petrochemical plants, and liquefied natural gas proposals for projects in Europe, Latin America, North Africa and the Far East, as well as the United States. For corporate clients he has undertaken merger and acquisition, and company organization studies.

James T. Jensen

Page 2

He is recognized for his expertise in natural gas supply, demand, regulation and pricing both in the United States and internationally. He has testified on natural gas issues before Senate and House Congressional Committees, before the Federal Energy Regulatory Commission and its predecessor, the Federal Power Commission, as well as many state regulatory agencies.

Mr. Jensen has written extensively on oil and gas matters. His recent papers include *Evolution of Market-responsive Pricing for Natural Gas in the U.S. and Its Effect on Gas Trade* (1986); *World Gas Reserves and Availability* (1986); *Factors Affecting Gas-based Industrial Development* (1985); *Natural Gas Deregulation and the Clash of Cultures* (1984); *Factors Involved in the Present Oil and Natural Gas Market Instability* (1984); and *Oil's Next Ten Years: "It Won't be Dull"* (1983).

Mr. Jensen has been a regular visiting faculty member of the Oxford Energy Seminar at St. Catherine's College, Oxford. He has also lectured on energy topics at other seminars conducted at Harvard, M.I.T., Northwestern and Oxford. He is a frequent speaker at U.S. and international energy meetings.

Mr. Jensen is a member of the American Petroleum Institute, the Society of Petroleum Engineers, American Chemical Society, Boston Economic Club, and the National Association of Petroleum Investment Analysts.



ALASKA SEGMENT

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

Alaskan Northwest Natural Gas
Transportation Company

YUKON PACIFIC CORPORATION
(ERA DOCKET NO. 87-68-LNG)

VERNON T. JONES, CHAIRMAN
ALASKAN NORTHWEST
NATURAL GAS TRANSPORTATION CO.

JANUARY 24, 1989

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

PREPARED STATEMENT OF
VERNON T. JONES, CHAIRMAN, OF BOARD OF PARTNERS
ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

AT PUBLIC CONFERENCE, JANUARY 24, 1989
ANCHORAGE, ALASKA
ERA DOCKET NO. 87-68-LNG (YUKON PACIFIC CORPORATION)

I. INTRODUCTION

I am Vernon T. Jones, making this statement as Chairman of the Board of Partners of Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest"), the consortium of natural gas companies designated by a Presidential decision and approved by the U.S. Congress to design, construct, and operate the Alaskan segment of the Alaska Natural Gas Transportation System ("ANGTS"). For the record, I am also the President and a Director of The Williams Companies, Inc., the parent firm of Northwest Alaskan Pipeline Company, the entity designated by Alaskan Northwest as its agent and operating partner.

The U.S. sponsors of the ANGTS have invested about \$ 1.5 billion to date in design, preliminary engineering, satisfying

government requirements, and construction planning for the Alaskan segment of the ANGTS. ^{1/} We made this expenditure in good faith, based on a framework of federal law, including explicit Congressional and Executive commitments to an overland transportation system to bring gas to the lower-48 states and the availability of at least the 26 trillion cubic feet of proved Prudhoe Bay gas reserves for this purpose.

We remain dedicated to bringing this gas to the lower-48 market at the earliest feasible date when the gas can be sold at market clearing-prices. That date is approaching much faster than is generally realized, which I will elaborate upon.

For a variety of reasons, which I will briefly summarize, issuance of an unqualified export license, as requested by Yukon Pacific Corporation ("Yukon Pacific"), would not be in the public interest. If, however, the Economic Regulatory Administration ("ERA") chooses to issue some sort of limited authorization, we strongly believe that the specific conditions we proposed earlier in this proceeding must be imposed to avoid substantially jeopardizing the availability of the proved Prudhoe Bay gas reserves and their delivery by an overland pipeline system to American consumers.

^{1/} The \$1.43 billion of investment (as of 12/31/88) is just for the Alaskan segment (i.e., the pipeline in Alaska and the North Slope conditioning plant), including interest and allowance for use of funds during construction. It does not include expenditures on the planned or already constructed and operating portions of the ANGTS in Canada and the lower-48 states. The currently operating sections comprise about one-third of the total mileage of the ANGTS.

II. DOMESTIC NEED FOR THE NORTH SLOPE GAS

The ERA has declared that domestic U.S. need for the gas is an important consideration in this proceeding. Let me make clear our understanding that a determination of domestic "need" for the Alaskan gas must be based on an economic test. If the gas is reasonably expected to be saleable on a free-market basis in the lower-48 states, without government subsidy, then it meets this prima facie test. By definition, if competitively-priced Alaskan gas is not available, demand for that energy could be met only if American consumers make use of higher priced and/or less desirable alternatives.

The currently proved Prudhoe Bay gas reserves, delivered to the lower-48 states by a pipeline system, can meet this free-market test based on the following considerations:

--Cost of the ANGTS. The revised cost estimate for the remaining elements of the ANCTS and use of a levelized tariff will make the delivered gas price highly competitive domestically during the proposed period of export. Mr. Cuba Wadlington, our Vice President for Regulatory Affairs, will elaborate on this and will also cover the concept we are considering for marketing the gas.

--Independent Supply/Demand Forecasts. Reasonable forecasts of a domestic "need" for the Alaskan gas during Yukon

Pacific's ostensible period of export (i.e., 1996-2021) 2/ have been made by independent, respected analytical organizations such as the Gas Research Institute ("GRI"), and have already been placed in the record. 3/

A new study lends additional weight to those we have previously cited. Entitled "Natural Gas: A Strategic Resource for the Future," it was prepared by the Washington Policy and Analysis consulting group ("WPA Report"), using a number of highly experienced energy professionals under the direction of a former Deputy Secretary of Energy. 4/ Regarding delivery of North Slope gas to the lower-48, it concludes that:

Precise timing is difficult to forecast, but it is reasonable to conjecture that a suitable pipeline could go into service within the first decade of the 21st century. This was one of the assumptions used in projecting supply to support the 'accelerated U.S. gas-use scenario' [that is recommended by the study team]. . . . (p.9)

In broader perspective, the study authors reported:

2/ Yukon Pacific's proposed "1996" starting date is likely to slip significantly in view of the following facts: (1) no gas sales commitments have been obtained; (2) no gas purchase agreements have been consummated; (3) no financing has been arranged; (4) the North Slope gas conditioning facility, a critical-path item with substantial regulatory ramifications, remains in limbo; and (5) Yukon Pacific, by its own admission, has not even commenced basic engineering of the system.

3/ Various supply/demand studies were introduced by Alaskan Northwest in its comments of August 24 and September 27, 1988. The GRI, as one example, projects commencement of Alaskan pipeline gas flow in 2007.

4/ Washington Policy and Analysis is a Miller and Chevalier Consulting Group; the study was released November 28, 1988. (Copy attached as Exhibit A.)

. . . a formidable and rapidly growing national consensus on the multi-faceted promise of natural gas for the rest of this century and into the next . . . [and] its increased use is an indispensable factor in the kind of mixed-and-balanced energy equation that best suits the nation. (pp. 1, 38)

--U.S. National Energy Security. Domestic demand for natural natural gas is almost certain to grow beyond current forecasts due to the rapidly increasing U.S. dependence on foreign oil, now over 40% and expected to be about 70% by 2010. ^{5/} Our nation obviously will become dangerously vulnerable to oil supply disruptions and/or price shocks. Much greater use of domestic natural gas predictably will become a public policy imperative as an important means to limit this vulnerability. The aforementioned WPA Report (Exhibit A), in a comparison to its "conventional wisdom" base case, concludes that the greater use of natural gas that WPA forecasts will result in a 2 million barrel per day reduction in demand for imported oil. The ANGTS, at full capacity, will provide the energy equivalent of 30 percent of this total--an impressive contribution to U.S. energy security by any measure.

President Bush, in addressing means to enhance U.S. national security last year, declared:

^{5/} See the WPA Report, page 25. See also the tabular comparison of the Baseline and Accelerated-Gas-Use Cases modeled by the WEFA Group (a merger of Chase Econometrics and Wharton Economic Forecasting Associates), as a backup to the WPA Report, dated November 22, 1988, "Baseline Scenario" (Table 8.2) for 2010, which projects a U.S. dependency on imports of 73% for crude petroleum and natural gas liquids.

There's no security for the United States in foreign oil. 6/ . We must turn to alternatives like natural gas.

--Environmental Requirements. Concern is growing about the damaging environmental effects of acid rain, ground-level ozone, carbon monoxide, atmospheric particulates, and the "green house" effect. Increased use of natural gas clearly can improve the situation, as we have previously established in the record. More stringent standards appear inevitable and will result in increased demand for natural gas. The WPA Report (Exhibit A) concludes:

A major force driving the introduction of more natural gas into the U.S. economy in the future could be an effort to meet environmental standards in the most cost-conscious manner. (p.19)

An even more compelling case is made in a report with recommendations by the National Academy of Sciences, the National Academy of Engineering and the Institute of Medicine, in concert, to President Bush, as follows:

. . . we should explore means for reducing energy demand without impeding economic growth, for example, by using fossil fuels with greater efficiency, as well as incentives and other means to increase use of the 'cleanest' fossil fuels such as natural gas. However, the finite availability of natural gas, a premium source and valuable chemical feedstock, also needs to be considered. (Emphasis added) 7/

6/ George Bush, Leadership on the Issues, November 1988, page 103. The statement was made on October 16, 1988.

7/ See National Academy of Sciences, National Academy of Engineering, Institute of Medicine, "Global Environmental Change, Recommendations for President-Elect George Bush," released January 5, 1989, page 3.

--Imports Are Not Enough. It is unrealistic to assume that U.S. imports of gas from Canada, Mexico, or of LNG can be obtained essentially without limitation, indefinitely and at more attractive prices than Alaskan pipeline gas. As we have previously pointed out, credible forecasts which take both price and availability into consideration call for gas from an Alaskan pipeline in addition to substantially increased foreign imports. The WPA Report (Exhibit A) reinforces this view. The Canadian National Energy Board, moreover, recently released a revised energy supply and demand forecast through 2005 which envisions an increasing Canadian reliance upon gas from "frontier" areas starting in 1999. ^{8/} Gas from these areas, including the Mackenzie Delta and Arctic Islands, will be subject to many of the same economic costs faced in constructing the ANGTS from a remote Arctic area.

Mexican gas imports do not appear to be a likely source of substantial future supply. Mexican Government policy is to maximize the use of natural gas domestically in order to obtain as much foreign exchange credits as possible from the sale of oil.

Regarding LNG imports, when the limited unused capacity in existing domestic terminals is used up, any additional capacity can then only be obtained by a costly,

^{8/} See Canadian National Energy Board, Canadian Energy: Supply and Demand, 1987-2005, September 1988 (Released December 7, 1988), pp. 114-118.

controversial and protracted process of siting and environmental approvals of major new terminals. Obviously, any increase in imports can only worsen our trade balance. It seems clear, therefore, that the U.S. gas market will be served by a variety of sources, each with its limitations; in such an environment, the overland delivery of the Prudhoe Bay reserves should be highly competitive. These reserves, therefore, are needed domestically.

--Potential Electric Power Generation Shortfalls. There is a very serious looming shortfall of electric power generation capability in the U.S. in the next ten years and into the next century. Natural gas turbines, which can be constructed relatively quickly and at far less cost than any type of steam-generating plant, are probably the only realistic hope this nation has to avert power shortages. I will elaborate.

The U.S. Energy Information Administration ("EIA") recently projected a base-case need for about 127 gigawatts of additional electric generating capacity by the year 2000, including about 33 gigawatts currently under construction. ^{9/} This total is equivalent to about 127 major new nuclear power plants. It is a conservative statement of need and assumes that major investments are

^{9/} A "gigawatt" equals 1,000 megawatts, the approximate capacity of a major electric utility generating plant.

made to extend a large number of existing electric generating plants beyond their normal retirement dates. If such life-extending investments are not made, the total requirement for new capacity by 2000 would be about 148 gigawatts. 10/

The American Gas Association ("AGA"), drawing on a number of other relevant studies, including those recently conducted by the North American Electric Reliability Council ("NERC"), concluded that between 50 and 105 gigawatts of new capacity will be required by 1997 in addition to plants currently under construction. 11/

The significance of these projections is the 10- to 12-year lead times required for regulatory approval and construction of new steam generation plants. Obviously, the lead time for such construction is being dissipated by every passing month. In the meantime, natural gas combined cycle or combustion turbines, which have far shorter lead times and are much less costly, are rapidly taking over the major share of future planned

10/ See Energy Information Administration, U.S. Department of Energy, Annual Outlook for U.S. Electric Power 1988, Projections Through 2000, August 24, 1988, page ix, Table ES1, et seq.

11/ See American Gas Association, Trends in Electric Generation Capacity and the Impacts on Natural Gas Demand, January 23, 1989. (Copy attached as Exhibit B.)

construction. 12/

The plain result of this growing trend in reliance upon natural gas for electric power generation has not yet been fully reflected in most supply/demand projections. The recent WPA Report, however, states:

. . . we felt confident with a detailed analysis that showed gas supplying nearly one-sixth of the primary energy used in generating electricity by 2010. This alone would require about 6 trillion cubic feet of gas annually, or more than twice as much as is being used now by the electricity industry. (Emphasis in original)

Two additional points are relevant: First, there is no question today as to the reliability and cost superiority of gas turbines for baseload power-generation purposes. 13/ Second, a unique attribute of North Slope gas, primarily as a result of the magnitude of the proven Prudhoe Bay reserves, is its ability to provide a long-term (up to at least 25 years), assured source of supply that will become increasingly important for the construction and financing of baseload electric generating plants.

--Summary of Domestic Need. We believe, in summary, that the accelerating demand for energy and particularly natural gas will burgeon in the years ahead, become highly

12/ See North American Electric Reliability Council, 1988 Reliability Assessment, the Future of Bulk Electric System Reliability in North America 1988-1997, September 1988, p. 20, 31.

13/ See Electric Power Research Institute, "Utility Turbopower for the 1990's," EPRI Journal, April/May 1988, pp. 4-13.

visible, and exceed most current projections by a wide margin. By any reasonable assessment, the Prudhoe Bay gas reserves will be needed by American consumers during Yukon Pacific's proposed period of export, even without slippage in its proposed 1996 starting date. When a major increase in U.S. domestic demand for gas becomes obvious--as it surely will--will Americans wake up and find that their major assured source of long-term supply has been committed to foreign export?

III. APPROVAL OF THE REQUESTED EXPORT
LICENSE SHOULD BE DENIED

The reasonably projected domestic need for Prudhoe Bay's proven gas reserves established by law, documented in the record of this proceeding, and briefly discussed above should by itself be sufficient for ERA to conclude that it must avoid any action that might jeopardize the overland delivery of that gas to American consumers. What remains to be discussed is: Why should commitment of the Prudhoe Bay gas to export be denied? There are two compelling reasons for denial:

1. Insufficient proved and economically transportable gas reserves exist on the North Slope to warrant construction of two major gas conditioning plants and two large-diameter pipeline systems in the same time frame.

The ANCTS has always relied upon the 26 tcf of proved gas reserves at Prudhoe Bay, notably gas associated with the production of oil and then reinjected into the Prudhoe Bay Field. This is well established in the President's Decision of

September 1977 and elsewhere in the regulatory record. ^{14/} This gas requires minimal gathering or production expenditures. Moreover, it is concentrated in a small area with substantial existing support facilities. For these reasons, together with the large quantity of proven reserves, the Prudhoe Bay gas is truly the "cream" or "highgrade" of whatever gas may exist on the North Slope. These considerations would be important anywhere else in the world. But they are of critical importance to economic viability in the Arctic. With respect to any potential North Slope gas sources other than the Prudhoe Bay Field, I can say with reasonable confidence that, even under the best of circumstances, uncertainties as to gas availability, transportability, and costs will delay any major pipeline project relying on such potential alternatives until long after a project using the Prudhoe Bay gas comes on stream.

The Yukon Pacific Application to ERA clearly spelled out its intention to rely upon the Prudhoe Bay gas reserves:

Yukon Pacific's supply procurement efforts will focus primarily on purchasing natural gas produced from the Prudhoe Bay oil field and, in particular, the gas cap from Prudhoe Bay's main oil producing formation--the Sadlerochit formation. (p. 13)

We have previously introduced expert statements by Mr. James

^{14/} See, for example, the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System, September 22, 1977, Section II, paragraph 2: "The expected volume of gas to be available initially from the Prudhoe Bay Field is 2.0 to 2.5 billion cubic feet per day...." The Report (p. 89) stated that this would include production from the main pool as well as the Kuparuk and Lisburne reservoirs in the Prudhoe Bay Field.

Jensen of Jensen Associates, Inc. regarding the "highgrading" of gas reserves, as intended by Yukon Pacific, and the probable effect on the ANGTS. Mr. Jensen will provide additional testimony on this subject today. The choice is clear for the reasonably foreseeable future, extending well into the next century, to wit: gas for American consumers when needed or Prudhoe Bay gas committed to export for foreign users, but not both.

2. A variety of legal grounds preclude approval of the export application.

We have already placed legal arguments and evidence into the record as to why an export license should not be issued or, at a minimum, should be strictly conditioned. I will not today further elaborate upon those matters, other than to reemphasize that the ANGTS sponsors have already invested about \$1.5 billion dollars in good faith reliance on explicit government representations. We will take all necessary actions in the appropriate forums to protect the sponsors' interests in that investment and will continue to work toward the stated national objective of providing Prudhoe Bay gas to lower-48 consumers. Mr. William J. Moses, General Counsel of Northwest Alaskan Pipeline Company and Mr. William J. Grealis, of the law firm of Akin, Gump, Strauss, Hauer and Feld, are available to answer questions.

IV. CONDITIONS REQUIRED IF YUKON
PACIFIC'S APPLICATION IS NOT DENIED OUTRIGHT

Throughout this proceeding, Alaskan Northwest, taking into consideration all of the points we have previously addressed and placed into the record, has strongly maintained that if any export license is issued to Yukon Pacific, it must include specific conditions along the following lines: (1) the proven Prudhoe Bay reserves needed to supply the ANGTS are not depleted; (2) construction of the ANGTS facilities has priority over those of the Trans Alaska Gas System ("TAGS") in order to avoid incurring additional costs that would be borne by U.S. consumers and rate-payers; (3) an appropriate cost allocation methodology is devised if the ANGTS facilities are used for the TAGS project; and (4) the ANGTS project has first call on North Slope gas for delivery to the lower-48 states, if it is needed to meet contractual obligations or to preserve the project's economic viability.

Furthermore, in order to implement these conditions and ensure that consumers and rate-payers are shielded from any and all costs associated with the proposed export, Alaskan Northwest maintains that any such authorization must not proceed in the absence of full NGA Section 7-type informational and filing requirements and must be further conditioned in one of two forms--either (i) mandatory curtailment and diversion of exports to meet lower-48 needs; or (ii) imposition of full economic liability for all costs (e.g., environmental, socioeconomic) associated with the non-availability of the exported volumes and

the forced domestic utilization of more expensive or less desirable fuels.

V. CONCLUDING REMARKS

In closing, I want to reiterate the ANGTS sponsors' conviction that the Prudhoe Bay gas reserves will be needed by American consumers and should be preserved for that purpose. Only the precise timing of an overland pipeline delivery system cannot be specified.

We believe, therefore, that it would be a tragedy for the United States if this major source of clean-burning domestic fuel and chemical feedstock, constituting the nation's largest remaining block of proved gas reserves, is committed to export. If it nevertheless is committed to export, I sincerely believe that we will look back on that event as an historic blunder.

Natural Gas: A Strategic Resource For the Future

WASHINGTON POLICY AND ANALYSIS
A MILLER & CHEVALIER CONSULTING GROUP

Exhibit A

**A Research Report
of WASHINGTON POLICY AND ANALYSIS
A MILLER & CHEVALIER CONSULTING GROUP**

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Natural Gas: A Strategic Resource for the Future

It is time to get specific about adapting this country's natural gas *policies* to its economic, security, and environmental *goals*.

For the third year, U.S. oil imports have jumped. Given the realities of energy resource distribution around the world, the future promises a tightening world oil market, increasingly dependent on the volatile Middle East. Such a future poses risks of oil-price shocks and oil-supply disruptions in the 1990s . . . while concerns also grow about air pollution, acid rain, and other environmental problems. This study shows that over the next 20 years the United States has the ability to increase its annual use of natural gas by approximately one-third. If it does so, the nation and the world stand to be cleaner, more secure against potential energy supply problems, and better off economically.

The challenge to the new administration and Congress is that at this moment our country is not headed in a direction that makes this *possible*.

As things stand, neither the U.S. supply nor demand for natural gas would grow rapidly enough to do what political leaders, environmentalists, economists, energy analysts, and academics now agree should be done. But conditions can change and be changed . . . and this report suggests how a new national attitude about natural gas can be helped along.

Both presidential candidates in the 1988 election backed the broader future use of natural gas. Now that the election is over, attention must focus on "how we can get from here to there." "Here" is the still-conventional wisdom in energy circles that U.S. use of natural gas for the year 2010 is likely to be at virtually the same level as today's if present trends persist. "There" means a much enlarged consumption of natural gas, especially at the expense of imported oil.

In this study we asked a number of questions about the future of natural gas. First, we tried to discern whether there was any way natural gas could fill the larger role assigned to it by both sides during the campaign. Then we pressed on with the hard question of whether the nation would really benefit if it did. Our conclusions are positive on both points. Natural gas can play a bigger role, but is not a panacea; and its increased use is an indispensable factor in the kind of mixed-and-balanced energy equation that best suits the nation.

As the study progressed, it focused on *means*. We asked what was needed to change the results of the model projection of gas use by the WEFA Group from a modest growth scenario of "business as usual" to an accelerated growth scenario in a "new gas environment" (with worthwhile effects on energy security, national productivity/

A Précis

competitiveness, and environmental quality). Surprisingly little, we learned . . . if supply and demand are *both* addressed.

Government and private-sector analysts should be especially interested in the *sorts* of assumptions about continuations or modifications to national energy policies that have been made here to test their combined effects. One set of mutually reinforcing actions by the federal government is outlined broadly on page 5 and amplified thereafter in the text. Individually, none of these steps may be terribly surprising to students or implementers of energy policy; but the fact that they are parts of an integrated approach is critical.

This is not to style our mix of policy options as a "take it or leave it" recipe. The fact is that natural gas is not a *perfect* fuel for all locations and economic sectors; nor is it one that can stand alone. A different mix could achieve similar results. But natural gas *can* play a larger role, and a mix of new policies can make a significant difference in energy security and the quality of our environment. Any combination of governmental choices in the real world involves trade-offs, and both the President and Congress could fine-tune a set of proposals such as these in a way that U.S. consumers and producers of energy will find to their satisfaction.

From a practical political standpoint, it is hoped that this report can constitute a reasonable framework for discussion in the weeks and months to come. Wherever possible, the potential costs and benefits of various courses of action are at least summarized, and the far more compre-

hensive reports generated by individual participants in the study will be available to those who can profit from their detail.

It also became clear in the course of this study that new initiatives in natural gas policies alone would not do enough. Other vigorous policies to encourage domestic energy sources and to foster conservation are essential if the nation decides to slow the rise in oil imports from insecure sources while preserving a healthy economy and environment. These include policies to stimulate domestic oil production, promote the introduction of clean-coal technologies, seek further safe and economic development of nuclear-based electricity, use "renewables" to the maximum practical extent, encourage more efficiency in energy applications, and support basic research on promising energy technologies for the longer term.

We have not drafted this as a contentious document, but as a consensual one—with interesting and valuable results. For instance, some readers may be amazed that the following pages do not dwell on such long-debated questions as open access to gas pipelines. Yet the gas industry itself is not of a single mind about some such issues—let alone suggesting that all regions of the country or all categories of consumers might reach agreement on them. Not one of the policy options that is mentioned here is likely to be considered radical. All are based on cautious study and free exchange among experienced observers who have served Republican and Democratic administrations or who have worked in one segment or another of the natural gas industry over the past several years. Each has been asked to

concentrate on findings and issues that can unite them.

The starting point of our study (and of this summary report) was a projection of patterns in U.S. energy demand for the year 2010. This baseline projection anticipated that technology and economics will continue to make the nation more efficient in applying energy resources—so that full-sized passenger cars in 2010 might routinely deliver about 50 percent more miles to the gallon than they do now, and each dollar of real gross national product (GNP) would be associated with the consumption of about 30 percent less raw energy in any form (moving well beyond all the conservation measures of the 1970s and 1980s). Furthermore, the base-case model was cautious in assuming a fairly modest rate of economic growth (an overall average of 2.5 percent per year); and it counts on the completion, licensing, and operation of nearly all commercial nuclear powerplants now under construction. Other modeling assumptions and approaches are reported far more fully in a separate publication.

The contrast between this base case (which foresees U.S. use in 2010 of natural gas that is equivalent to about 9 million barrels of oil per day) and the much higher supply-and-demand that the analysis shows resulting from the enumerated policy options (equivalent to roughly 12 million barrels per day) is striking.

These two hypothetical “cases” are presented graphically on the next page. Neither is a *prediction*; there are always enough imponderables to make long-term prophecy a fool’s game. But the projection method is clear and open to inspection. The potential differences between these two prospects arise essentially from a few concerted “mid-course corrections” in federal energy policy. We are convinced that options of this type deserve examination *now*.

The bulk of this report asks a series of questions . . . and provides considered, cogent answers:

Where can all that gas come from? . . .
and how is it to be delivered? Page 6

How and where can natural gas fit in?
. . . and how soon? Page 16

What does gas “buy” us in terms of energy
security? . . . and at what cost? Page 25

How much can natural gas do for
environmental quality? Page 29

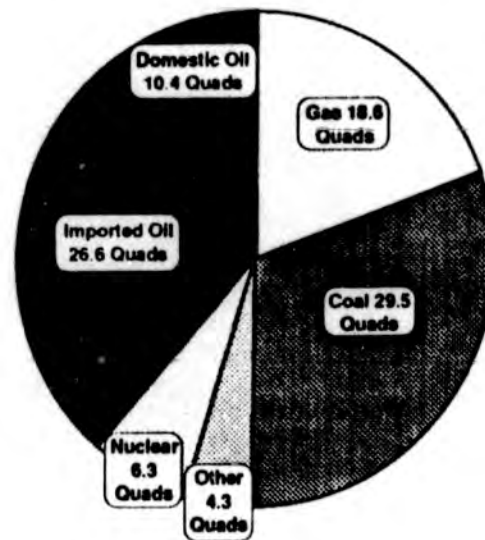
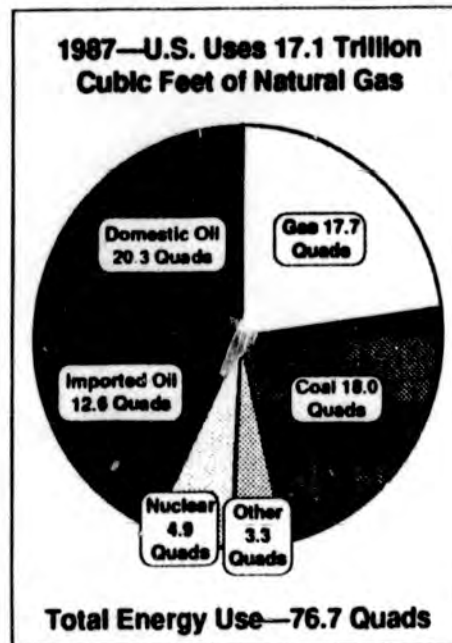
What are the implications for budget,
overall growth, and international
affairs? Page 34

*The difference between this projection,
based on "conventional wisdom" . . .*

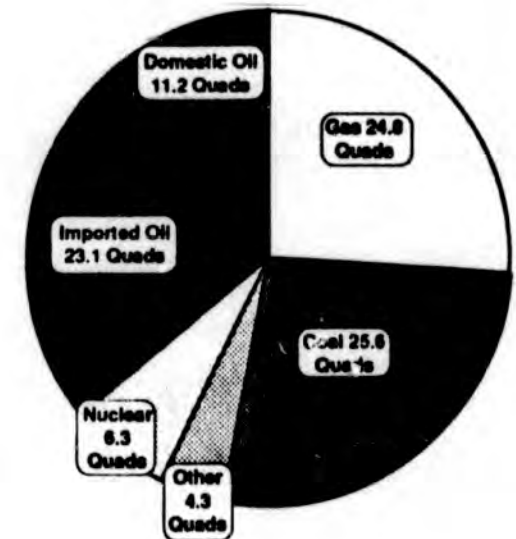
*. . . and this one, based on
"a new environment for gas" . . .*

**2010—U.S. Uses 18.2 Trillion Cubic Feet
of Natural Gas**

**2010—U.S. Uses 24.1 Trillion Cubic Feet
of Natural Gas**



Total Energy Use—95.7 Quads



Total Energy Use—95.3 Quads

... came from certain budget-conscious assumptions about federal attitudes toward:

A "least-cost" strategy to achieve desired environmental standards

- Basing enforcement on *performance* rather than mandating specific control *techniques* (thus favoring such low-cost methods as trading emission "credits" and burning gas in conjunction with other fuels, in preference to coal "scrubbers").
- Monitoring compliance in terms of areawide "bubbles" rather than individual facilities (thus encouraging the selective, cost-effective replacement of older equipment).
- Assisting local efforts to clean up air pollution by specifying that federal funds for public transport fleets (for example, from the Urban Mass Transit Administration) be used exclusively for low-polluting vehicles.

Targeting of R & D

- Research and development on the geoscience that underlies natural gas production.
- Federal funding and other incentives for R & D associated with gas-use technologies—including advanced combustion turbines for generating electricity, cooling by gas, vehicles, and the "co-firing" of gas with other fuels.

Improvements in the "deliverability" of gas

- Use of all responsible procedures at the federal government's command to expedite the licensing of new capacity for pipeline delivery of gas to regions that are now heavily dependent on imported oil.
- Encouraging adequate storage of natural gas in the context of an emerging new supply-and-demand context.

Incentives to exploration and production

- Prompt identification and lease of the most promising federal lands where exploration can be deemed environmentally acceptable.
- Limited tax credits (for example, 10 percent for all exploratory drilling activity, plus 10 percent for redevelopment drilling in old fields with newly recognized additional potential).
- Adjustment of federal royalties to permit earlier recovery of investment in productive wells . . . and a sliding time-scale of royalty collections, based on market prices (but expanding ultimate return to the Treasury).
- Complete decontrol of wellhead prices for all gas.

Note that some of these policy options apply to basic gas supply for the nation, others apply to the demand side of the market equation, and a couple relate to both supply and demand. Each is described—with its "upside" and "downside"—in the text of this report and supporting publications.

Wherever possible, the effects of individual actions were factored into supply and demand estimates—although some are obviously difficult to quantify. It is clear that various elements of an entire program (this nominal one, or any other) *interact* to produce a cumulative result that can surpass the sum of its parts—so that concurrent action on *all* fronts is desirable if not essential.

Where can all that gas come from? ... and how is it to be delivered?

**The United States Has
More Producible Gas
Than Most People Thought**

There is no doubt now that enough natural gas *can* be produced and delivered from secure sources at reasonable prices to let gas serve this country as an important "bridging fuel" to 2010—by which time even more-environment-friendly renewable sources might be nearly ready for widespread and economical use.

This represents a major turnaround in outlook. As recently as five years ago, the carefully prepared biennial *Projections* volume of the Department of Energy (DOE) went virtually unchallenged in asserting that new U.S. gas reserves were dwindling fast and that conventional production was likely "to decline at 2 to 5 percent per year from 1990 to 2010." Yet resource estimates made earlier this year by both DOE and the industry's Potential Gas Committee (PGC) agreed that there is enough gas left in the ground for today's technology to continue pumping it out economically at present rates for at least 35 years. An additional decade of supply awaits us in gas that could be recovered if prices at the wellhead rise modestly in the future to the equivalent of between \$3 and \$5 per thousand cubic feet (Mcf)—in other words, the counterpart in energy content of oil at roughly \$20 to \$30 per barrel today. Furthermore, even this fails to take into account future supplies of "unconventional" gas—the sort that budding technology might

derive from sources such as coal seams and shale formations. Their development could extend the total available resources by another one-quarter to one-third.

What caused this fresh optimism about domestic supply? No new giant gas fields were discovered (although Mobile Bay and deep waters of the Gulf of Mexico show great promise). In fact, lower world prices for oil have drastically reduced U.S. exploratory drilling over the past three years—although the nation's *production* of natural gas has defied the gloomiest predictions and headed back up again. One reason for rising confidence about gas resources is that a better understanding of geology shows how irregular underground reservoirs of gas are—revealing that closer and better spacing of wells makes it possible to drain fields much more efficiently, even when only the conventional production methods are employed.

A knowledge-jump of this nature is hardly unprecedented. The internal combustion engine nearly lost the U.S. automotive market to steam-cars and electric vehicles early in this century, because gasoline supplies were feared to be inadequate—until new ideas about where petroleum existed led to finding the huge Spindletop Field. Shortly after World War I the domestic outlook for hydrocarbon resources was bleak again—until advances in geophysical surveying and

production brought about development of previously unexpected new fields in West Texas. The long-term value of broadening continually our understanding of geoscience cannot be disputed.

The new DOE study gives a series of specific examples—along the Gulf Coast, in South Texas, and encompassing parts of Kansas and Oklahoma—where fields that had been abandoned or were assumed to be nearing total depletion are now diagnosed as holding up to 25 percent more gas than was estimated initially—in untapped reservoir compartments that simply are unconnected to those drained earlier. Apparently this holds true for many of the 10,000 fields the panel evaluated nationally. Much of the additional gas can be located and drawn off merely by sinking new wells between the old ones . . . and by putting wells closer together as new fields are opened up and old ones are extended.

Obviously, that process can be made far more efficient through geoscience research if it becomes possible to target such heterogeneous reservoirs more accurately (for example, through high-resolution seismic imaging) and to contact more of the gas-bearing rock (for instance, through advances in horizontal drilling). In many fields, older wells can now be reevaluated with technologies that were not available when these wells were drilled 10 to 40 years ago—with even newer methods in the testing stage that will make this process much more efficient in the 1990s. It should be possible to locate and reach gas resources that were bypassed initially but can now be connected to existing pipelines as deeper reservoirs are depleted.

The pattern of new gas discoveries in the United States has changed a couple of times over the history of the industry. Nearly half of all the 390,000 U.S. wells that have ever been drilled have been sunk since the mid-1970s; but the average addition to gas reserves *per well* dropped suddenly at that time to only about one-quarter of what it had been since 1900. The heartening news is that well output has held remarkably steady at this new plateau; and Professor William L. Fisher, of the University of Texas at Austin, offers convincing analyses to support the expectation that it will remain so through the next 300,000 completions. The gist of his interpretation is that few "elephant" fields remain to be found (with the possible exception of offshore—where the average well now produces 7 times as much as the national average in reserve additions—and in largely untapped Alaska). But there are many more small and moderately sized reserve pockets than had been recognized, and advanced technology has increased the success rate in locating them.

In our judgment—bolstered by discussions across the industry as well as with academics—modest tax incentives probably would trigger considerable additional investment in both exploratory drilling and "redevelopment" of old fields. For purposes of modeling, we tried to gauge the effects of a 10-percent tax credit in each case. In the case of redevelopment for older fields that are past exploitation by conventional means alone, "qualifying" fields might be limited to those beyond a certain age relative to discovery and "full" development and those whose annual production

**Secure Sources Include
Some Gas Beyond the Borders
of "The Lower 48"**

showed clear decline over a five-year period such as 1978-82 (before market conditions prescribed the curtailment of production for economic reasons apart from resource depletion).

In the scenario for accelerated gas production and use, it is estimated that annual conventional domestic output (exclusive of Alaska) can actually increase by about 2 tcf—including a rising contribution from "tight sand" deposits. Also, unconventional production is projected to become more economically sound as energy prices rise in response to tightening petroleum markets around the world during the 1990s and geoscience leads to advanced production technologies.

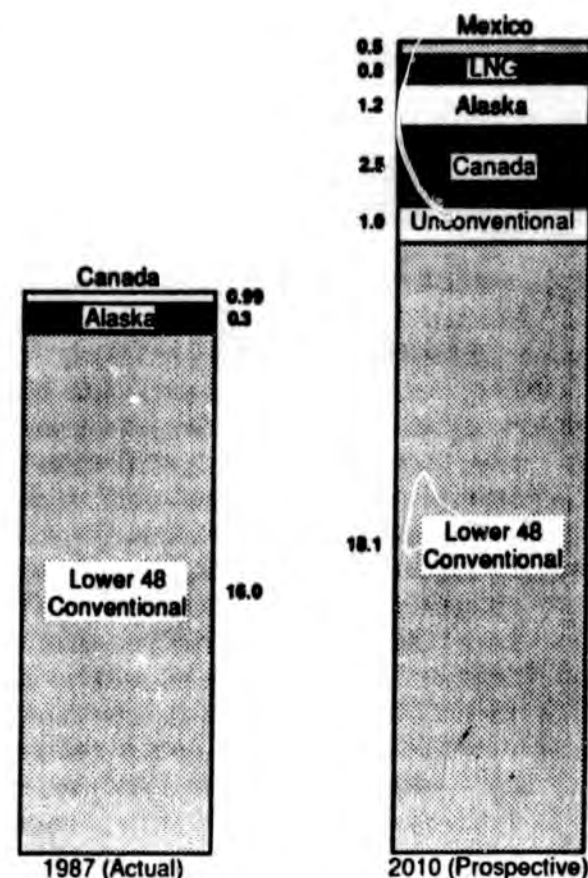
This means that domestic wells in the "Lower 48" can remain the backbone of national supply for decades to come. But there are four other sources of natural gas we should also be able to count on in a projected total of 24.1 tcf annually by 2010—Canada, Alaska, Mexico, and some imports in the form of liquefied natural gas (LNG).

Canada: In 1987 the United States was already importing more than a trillion cubic feet of natural gas each year from its good neighbor to the north. Preliminary data show that this level may climb by another 25 percent this year; and the interrelated dynamics of Canadian reserves, pricing, and pipeline capacity suggest that our net imports from Canada might hit 1.5 tcf as soon as 1990. This would leave ample time in which to develop the delivery infrastructure and market to support a 2.5-tcf annual import flow by 2010.

Closer trade relations with Canada are mutually beneficial in energy. For Canada, the gas sales envisioned would create the incentive and

the opportunity to develop frontier resources that would increase its reserve base dramatically in years to come. In return, this country can foresee a secure supplement to domestic production at competitive prices.

Sources of Cost-Competitive U.S. Gas
(trillions of cubic feet)



Alaska: Alaskan gas resources are substantial—with the known reserves of 26 tcf on the North Slope alone far exceeding a full year's supply for the entire country; but these have barely been developed because markets are so distant. The sparsely populated state is self-sufficient in satisfying its own present demand, of course; but this amounts to only about 300 billion cubic feet (bcf) per year. Another 50 bcf annually is being converted into liquefied natural gas for shipment via refrigerated tanker to Japan.

Under appropriate market conditions (that is, when the real price of gas approaches today's equivalent of \$4.00 per Mcf and looks as if it is likely to stay at that level or higher, while substantial demand exists for gas as a substitute for oil), Alaska could become a significant supplier by pipeline to the Lower 48. Precise timing is difficult to forecast, but it is reasonable to conjecture that a suitable pipeline could go into service within the first decade of the 21st century. This was one of the assumptions used in projecting supply to support the "accelerated U.S. gas-use scenario" highlighted on pages 4 and 5.

Mexico: Large gas imports from the south were close to becoming a reality more than a decade ago; but then progress toward a bilateral agreement ended abruptly and Mexico decided to focus first on developing more domestic applications for its gaseous fuel. A new U.S. administration that has expressed its goal of improving political and economic ties between the two countries should have ample opportunity to revive the project during the 1990s; and those international imports by pipeline could easily begin by the turn of the century—rising to perhaps 500 billion cubic feet by 2010.

Mexico's proved reserves of gas are nearly 40 percent as large as those in this country (76 versus 192 tcf), although its total resources (about 200 tcf) are only about one-fifth those of the United States. Because Mexico's annual domestic consumption is still only about 1.25 tcf, however, vigorous growth in our country's demand could well prove attractive to a market of common value.

LNG Tankers: Norway, Algeria, and Nigeria are all possibly reliable suppliers to the United States once trade in liquefied natural gas to this country starts up again—perhaps by 1990. Development of the North Sea fields in particular has already made natural gas more promising as a European fuel, but it has also brought into the spotlight vast additional reserves of gas that ought to be co-produced while North Sea oil is being tapped. At the same time, unused LNG tankers are available now at reduced cost.

If adequate demand for gas develops here, there seems to be no question but that LNG will be able to serve certain markets—even now, but certainly in any situation when pipeline capacity from the major producing areas might have difficulty satisfying some regions' demand. By 2010 such shipments were projected in the WEFA model to total 0.8 tcf. However, no additional deep-water U.S. port facilities suitable for receiving LNG were assumed before 2010.

Despite our country's huge hydrocarbon resources—even in the Lower 48—not nearly enough exploratory drilling is under way at present to ensure that these will be converted into "proved reserves" and final production of gas at a rate that could accommodate the accelerated-use

**The Level of Drilling
Is a Separate Issue
From Basic Resources**

schedule postulated by this study. The return to actual and potential producers of oil and gas is currently too small—partly because the price being paid for delivered gas is low, and partly because the combined “take” from royalties, production taxes, and state leases is relatively high (for example, totaling an average of about 44 cents per Mcf at a federal leasehold well off the coast of Louisiana, at a time when the producer is receiving only about \$1.75 in all for each Mcf at the wellhead).

Part of the problem lies in the so-called “gas bubble”—a temporary imbalance between supply and demand that was brought about largely by a coincidence of circumstances: a) rapid price increases in the early 1980s, driven by peculiarities

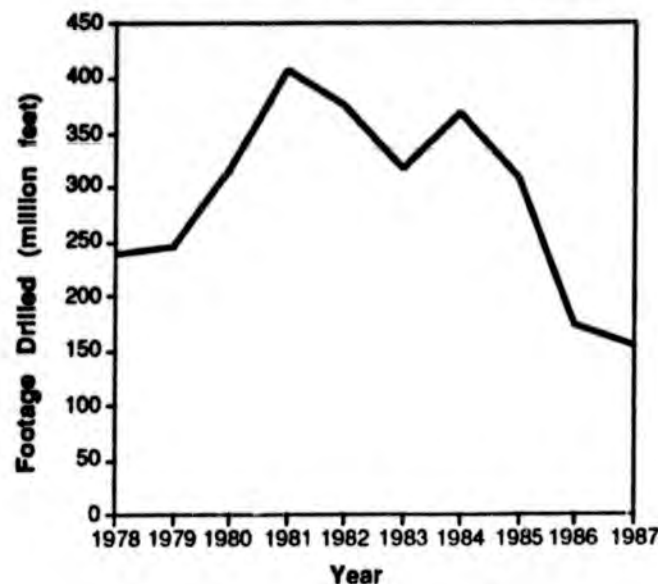
of the Natural Gas Policy Act; b) economic restructuring across the nation, and a general economic downturn in 1982; and c) vigorous energy conservation steps, which dampened demand for all fuels. Most of the experts involved in this particular study believe that it is fading away and should disappear by 1990.

Part of the difficulty also arises from the fact that wellhead prices for some sources of natural gas are still technically under federal regulation—although three-quarters of all gas is effectively deregulated.

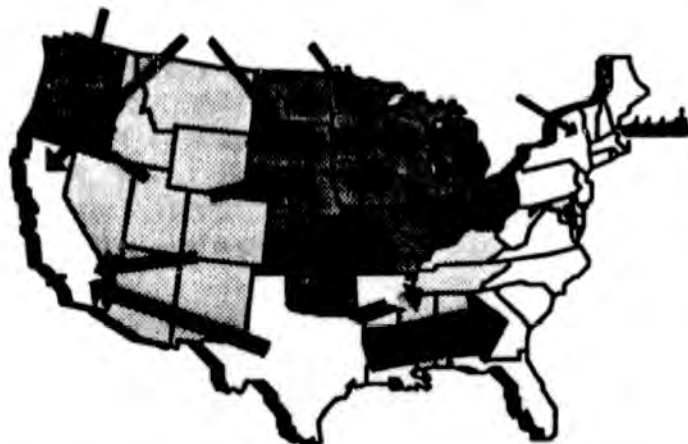
A major contributing factor, however, is the large amount that must be paid out in royalties and taxes as soon as a well enters production. Drilling is a capital-intensive business—and a risky one to boot. The theory behind delaying government royalties and taxes (another policy option assumed in this report) is that faster payoff to an explorer and producer of gas should encourage the search for new reserves and the brisk development of wells that prove successful. Ultimately, this leads to speedier and more efficient application of the nation’s resources. Thus, it also increases government revenue overall.

Some 1.1 million miles of pipeline are used in the United States today to gather, transmit, and distribute natural gas. We know that this network is capable of delivering more than 23 tcf annually as it stands, because the smaller pipe-grid that existed 15 years ago actually handled more than 22 tcf in 1973. Within limits, increased pressure can easily and safely raise the volume of gas being carried over long distances.

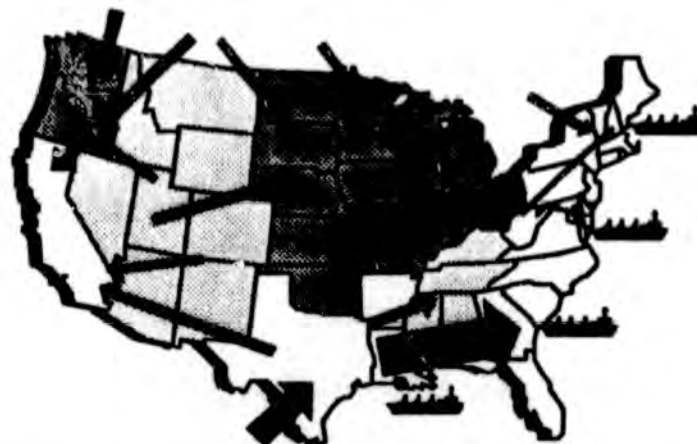
Oil and Gas Well Drilling, 1978-1987



1988 Gas Transmission Patterns



2010 Gas Transmission Patterns



"Packing" the lines is a common practice during periods of high demand (for example, in cold weather, when the requirement for gas heating in residential and commercial buildings soars). Even this could not accommodate the sharp seasonal variations that occur, however; so local distribution companies (LDCs) as well as bulk suppliers have far greater underground storage capacity than the average gas user ever imagines. At the end of October 1986, for instance, the amount of gas in such storage across the United States exceeded 7 tcf. This is the heat-equivalent of far more than a billion barrels of oil—thus representing twice as much energy content as the federal government's massive Strategic Petroleum Reserve (SPR), which was created and is continually being augmented as an emergency safeguard against future disruptions in crude oil supply. And the Energy Information Administration now estimates the industry's *total* storage capacity for natural gas at something above 8 tcf.

But another huge question about the timely delivery of natural gas remains: "Do pipelines carry it to where it will have to go?"

The answer is "No, not completely." A possible breakdown of how the yearly demand for 24 tcf of natural gas might evolve in this country is discussed in the section of this report that begins on page 16; but the two generalized maps above exemplify at a glance how some gas transmission patterns might have to change. Although most gas in 2010 will come from the same geographic regions as it does now, the Mountain States should be a more significant domestic supplier. Alaskan gas ought to be available by pipeline, and perhaps half a tcf of Mexican gas may be in the U.S. supply picture. LNG should be arriving from overseas. Such knotty questions as how future air quality standards will be specified leave the *exact* pipeline needs unpredictable from the distance of a couple of decades.

**Spare Pipeline Capacity,
New Routes, and Storage
Fit Into the Mosaic**

When everything else is equal, history has shown that the demand for natural gas goes hand in hand with its availability. Gaseous fuel was used sparingly by population centers along most of the Atlantic Seaboard through World War II, when it was still being *synthesized* primarily in local "gas works." Once the big wartime pipeline for oil called "Big Inch" was converted to deliver *natural* gas from producing areas in the south, however, both the means of applying it and its total consumption expanded impressively. Even now, the populations of Louisiana and Maryland are almost identical in size; but the first of these two states (in the midst of gas-producing country) uses more than nine times as much gaseous fuel as the latter (where transport costs are higher).

If the Northeast (which is still heavily dependent on oil) wishes to substitute more gas, hundreds of miles of new pipeline will have to be installed. In fact, the Federal Energy Regulatory Commission (FERC) has recently granted construction permits for about a dozen additional gas-transport facilities for that area, and these will boost receiving capacity there by nearly 25 percent.

Unfortunately, potentially avoidable regulatory delays in the permit-granting process have been one of the chief constraints on the expansion of gas markets. Recently, FERC speeded up its own activity by declaring an "open season" for Northeast projects, during which a number of similar or related applications that have been stacking up can be considered simultaneously. Still, federal regulators have not shown enough scheduling and coordinating discipline thus far to produce appropriate speed in licensing pipelines into heavily oil-dependent regions.

Federal initiatives alone might not break the logjam completely, because state public utility commissions (PUCs) and other authorities below the national level are usually also required to grant permission in advance for such construction. Nevertheless, Congress and the administration can set an important example if the consensus emerges, regionally and nationwide, to boost the possible use of gas on environmental, economic, and security grounds.

It would have been far beyond the scope of this study (as well as presumptuous) to try to draft either legislation or administrative rules to facilitate the building of new pipelines where needed. The policy option we have surfaced in this regard needs detail work. Still, we feel confident in offering some general guidelines, which were observed in our modeling effort: 1) Whatever new steps are taken should be responsible ones from the standpoint of environmental protection. This was an easy stricture to accept, because once underground pipelines are in place they do not represent either an unacceptable threat to public safety or any insult to aesthetics. 2) Special consideration might well be given to applications for new pipelines that can serve areas that are heavily dependent now on other fuels, for which the substitution of gas offers demonstrable benefits. A similar case can be made for regions in which dangerously shrinking reserve margins for electricity-generating capacity point to gas-fired turbines as the most practical and timely solution. On both counts, the policy envisioned appears to be fundamental in permitting supply and demand to grow in tandem—as they must.

Additional gas storage, mentioned earlier as a possible insurance system to protect against future global oil supply problems, is also a means in itself to expand current domestic supply. Producing wells churn out gas continuously, and pipelines will have to be filled as much as possible on a year-round basis if they are to render maximum service. Yet demand is bound to remain seasonal to some extent. An even more comprehensive storage system—decentralized so as to offer maximum flexibility—can “level the load,” much as pumped-storage reservoirs do for generators of electricity. With either energy source, this approach makes possible maximum delivery of the product in the most economical way.

It cannot be repeated often enough that supply and demand interact. So do a number of the government policies addressed in this report—especially in regard to bringing the United States’ secure supply of natural gas to the level discussed by 2010.

Today’s clearer understanding of the heterogeneous nature of underground gas reservoirs means that U.S. *production potential* has increased. Thus, the producible domestic *resources* of natural gas (the total amount we may reasonably count on drawing from the earth ultimately, using specific technology and confining production costs to certain levels) are larger than was thought previously. But the fact persists that too little is being done right now to *pinpoint* new reserves so they can be brought to the surface. Unless there is a turnaround, the level of reserves will begin to erode again next year . . . and in the years to follow.

No single, simple solution to the dilemma appears to exist. Instead, a variety of *coordinated* actions came to mind in devising a model that might take full account of the new national attitude toward gas.

Companies in the U.S. gas industry, large and small, are more likely to step up exploratory drilling once again if they have somewhat greater assurance that the fruits of their investment will be marketable at returns that are based on risk and *true* value of the commodity—rather than on oil-price manipulations by an international quasi-cartel or on gas-price ceilings imposed by their own government. Deregulation of wellhead prices is important; and limited tax incentives (only for exploration or for redevelopment drilling in older fields that now stand to be rejuvenated) appear to be needed as well—because of justifiable fears that OPEC behavior can force world energy prices *down* capriciously as well as *up*.

Perhaps 35 percent of the gas that remains to be produced by conventional methods in the United States lies in areas under federal jurisdiction. Rather than exclude blocks on the map wholesale on the basis of emotion and political impulse, it seems to make more sense to establish priorities on the basis of the relative likelihood that gas might be found. This may require something of a public education program, because it is not generally understood that *most* exploratory drilling efforts are destined to wind up as “dry holes.” Environmental risks will never be eliminated completely either. Despite these cautions, an intelligent and informed balance needs to be struck between the equally important goals of resource-need and dedication to keeping our land,

**Various Policy Steps
Reinforce One Another
In Ensuring Gas Supply**

air, and water in good shape. Once it has been established with reasonable confidence that attractive targets exist for environmentally sensitive exploration, development, and production, such areas should be made accessible (through a sound competitive bidding procedure)—so that the private sector can undertake the job.

Although it seems safe to forecast that energy prices will escalate over time, they will almost surely not rise along a smooth curve. New drilling (which has been cited as a key ingredient in increasing future supply) would be likely to increase still more if government royalty payments could be deferred until the initial capital investment in any successful well had been covered. Production certainly would not cease at that point, because profits would continue so long as revenue from the gas was adequate to pay operating costs and a full, *higher* royalty. Analysis shows that this would bring a greater return to the government, so this is not a matter of authorizing subsidies.

Even before drilling begins, the recent hike in resources based on strategic "infill" production shows that research in geoscience can pay large dividends. The federal government has been committed nominally in recent years to support meaningful R & D on energy topics that are basic to resource development; but budget limitations have held actual DOE expenditures in this field to minimal levels. This year, however, the Department began a three-year, \$22.25 million joint research venture with the Gas Research Institute and the State of Texas to develop and demonstrate cost-effective approaches to recovering

additional reserves from conventional gas reservoirs.

More opportunities exist: efficiency in finding and developing a very large number of small-to-medium-sized gas sources is the key to economics—so that a national "reservoir framework" and trustworthy "reservoir models" would operate synergistically with research on high-resolution geophysics and better geostatistical methodologies. Broad R & D on drilling and hydrocarbon-recovery techniques also seem appropriate for cost-sharing.

Once again, the framers of this report recognize that they are clearly not as well equipped as the President and Congress to decide how these requirements compare with other national needs within the strictures of Gramm-Rudman and a clear resolve to limit the deficit. However, it seemed reasonable to assume that an appropriate level to *accomplish* a great deal in programs of this kind might be a total of about \$100 million per year for several years—divided on approximately a 40-60 basis between gas and oil. Laboratory and field research needs to be accompanied by some effort in actual *demonstrations* of development work by joint ventures involving the government—especially when federal support goes beyond basic geoscience to advanced drilling and production techniques.

The long-run payoff to the nation can be great from such relatively minute taxpayer investments as were assumed in this projection, but fresh invention and creative perceptions of nature do not appear overnight. If we are pointing toward the year 2010, fiscal year 1990 will be none too soon to begin.

In the case of natural gas, furthermore, it has already been noted that *availability* is as critical as basic supply. The existence of an adequate delivery network—made safer and more efficient by increased storage capacity—is an additional constituent of an overall national commitment and plan that cannot be overlooked.

The final section of this report examines the respective costs we calculated for all these plan-components—along with their potential benefits, to the extent they could be quantified. Suffice it to say at this point that some program of this overall shape and scope appears to be worth doing.

How and where can natural gas fit in? ... and how soon?

Relative and Absolute Prices For Energy Will Underlie Gas Substitution Patterns

Projecting the exact way in which one-third more natural gas might be used effectively in this country by 2010 is far more complex (and subject to change) than demonstrating that a reliable and reasonable supply to support this level of demand can be developed. However, the model results were encouraging. Clearly, more gas use *can* make economic sense.

The graphics on the following page present one scenario of U.S. energy consumption (among many that could be proposed for the same time frame with equally sound reasoning) in which there is a cost-practical division of about 24 trillion cubic feet of natural gas by use-sector. We believe that market-based forces could bring supply and demand into a healthy balance at this level without the sort of massive interventionist energy policy that foundered in the past (for example, fuel allocations on the demand side, or the Synthetic Fuels Corporation on the supply side).

The degree to which natural gas substitutes in the future for oil (to make U.S. energy supplies more reliable), for coal (to limit air pollution and acid rain), or for any other energy source depends heavily on what the prices of gas will be *to various potential consumers*—especially in comparison with what the same individual, company, or institution would have to pay if another energy source were chosen instead. Such “burner tip” prices for

gas vary appreciably now—not only because of differences in pipeline distance from one part of the country to another, but also because the rates at which gas may be purchased from a regulated utility company by any specific *category* of customer (residential, large or small commercial, industrial, electrical generating utility, and so forth) must be approved by local public utility commissions, whose policies are not uniform.

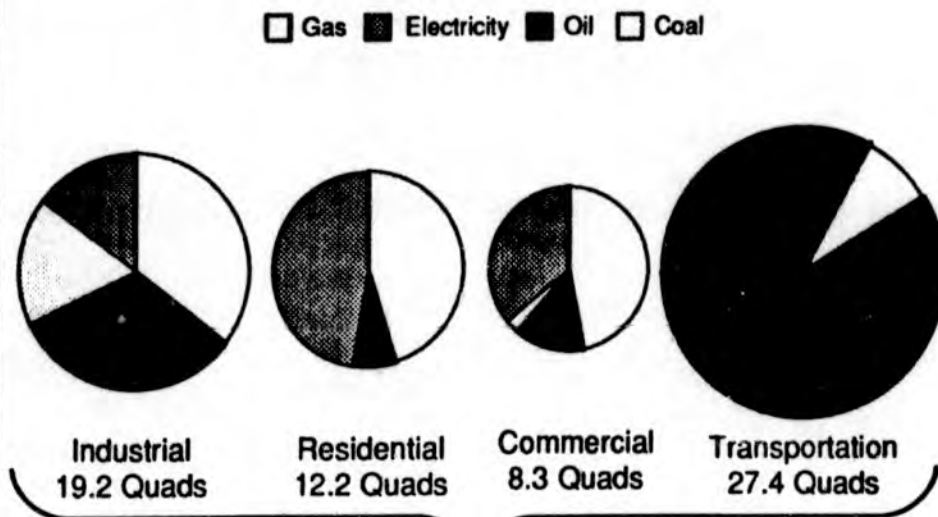
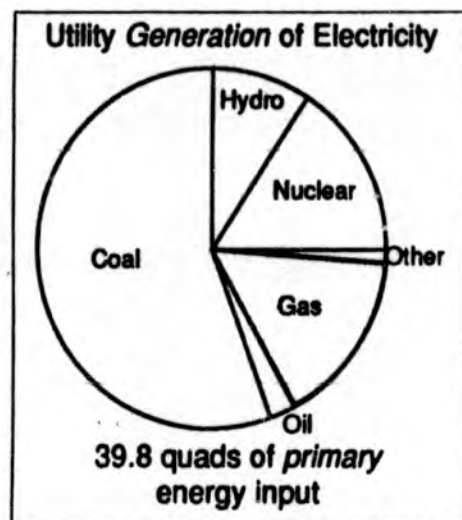
This study accepted the broad consensus opinion that “real” energy prices will rise after a period of relative stability—though not as steeply as was generally suggested a few years ago. We assumed that the average price of oil to U.S. refiners might rise to \$37.50 per barrel in terms of 1988 dollars by 2010. But we estimated that the wellhead price of domestic natural gas would increase at a *faster* rate—to \$4.50 per thousand cubic feet. Coal at the minehead, on the other hand, was pegged at an average of \$34.70 per ton by 2010—not much more than it has been in recent years.

The very substitution of gas for other fuels affects the prices of those other energy sources too, through simple competition. As demand for oil softens, for instance, sellers of the fuel find it more difficult to keep the price up. To the extent that gas replaces oil, gas thus undercuts its own competitiveness in terms of comparative dollar-cost per Btu (British thermal unit). At the

One Way to Utilize 24.1 tcf of Natural Gas Economically in 2010:



... making these contributions to the respective energy-using sectors of the U.S. economy:



These end-use numbers include heat-equivalent of electricity *as delivered*.

Annual use of a "quad" (one quadrillion British thermal units) = generic equivalent of about half a million barrels of oil/day.

same time, however, more widespread use of natural gas should tend to reduce even further the capital cost of certain types of equipment that employ gas—through the cost-saving mechanism of volume marketing and mass production. And the overall cost of using one fuel in preference to another may depend as much or more on the amortization of equipment as it does on how much it costs to fill the tank.

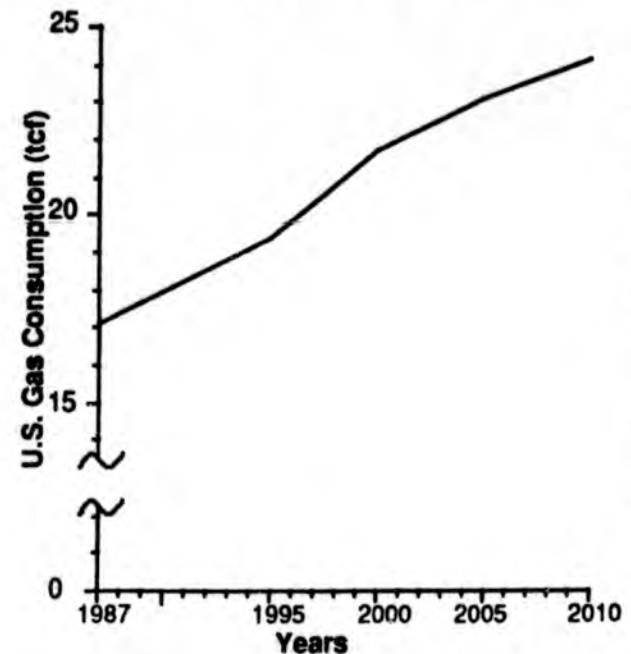
In the case of oil and gas, there is the added complication that both of these fuels sometimes flow from the same well; and the obvious divergences in their price-trends depend on numerous other factors. We tried to consider many of these in the model, but overconcentration on methodology in a summary report of this sort might only obfuscate some of our most important conclusions in regard to potential demand—which are these:

- An overall energy demand for roughly 95 quads was projected in the “accelerated gas use” case for 2010, slightly less than the 96 quads in the “baseline” case. The use of more gas in the roles projected here would tend to reduce the total amount of energy required to provide specified services or maintain a given output—because of greater efficiency in the technologies envisioned (especially combustion turbines). Counteracting this effect is the fact that economic activity would simultaneously be encouraged to rise (based partly on stimulation of the domestic gas and oil industry, and partly on an improved trade balance), drawing the demand for energy upward along with GNP. These “big picture” matters are reviewed in the international

and macroeconomic section that begins on page 34.

- U.S. demand for natural gas might rise in a relatively smooth curve over the next three decades (and, in fact, this is the way it was projected in the computer analysis of our model—as shown on the adjacent graph); but this need not be the case. Judging from historical precedent, demand seems almost as likely to increase in spurts—either as gas-using technologies such as combined-cycle turbine generators, dual-fuel boilers, and

The WEFA Model Projected Gas Use To Increase in this Fashion, But Rises Might Come In Steps



vehicles fueled with compressed natural gas (CNG) are popularized nationwide, or as greater pipeline capacity expands regional markets (most logically, in New England).

- A major force driving the introduction of more natural gas into the U.S. economy in the future could be an effort to meet environmental standards in the most cost-conscious manner. (A section dealing specifically with this starts on page 29.)

In many areas, the local suppliers of gas and electricity have been fierce competitors. To some extent this will continue—particularly where the nascent technology for gas-cooling starts to challenge electric heat pump systems. However, the relationship between the gas and electricity industries overall might be in for some basic changes—as the former becomes a crucially significant supplier to the latter.

For a number of reasons, the demand for electricity is expected to grow more rapidly than the consumption of energy overall. Our assumption was that the growth-ratios of electricity use and total energy use to GNP would be 0.8 and 0.7, respectively, between now and 2010. Nevertheless, the construction of new generating capacity in this country has slowed precipitously. We are frequently reminded that it has been almost 15 years since the order was placed for the last of the nuclear powerplants still being built, but construction of large coal plants has also slowed. The Department of Energy was consciously conservative in its *Energy Security* report nearly two years ago when it warned that at least 100 gigawatts of additional generating capacity appeared to be

necessary by the turn of the century... and hinted graphically that the potential shortfall was likely to widen thereafter. Yet utilities are still loath to place long-lead orders for capital-intensive fresh construction.

Apart from the special advantages of natural gas as an "environmentally benign" heat source for generating electricity, gas turbines inherently are easier and less costly to *build* than steam-generating plants of any sort. For this reason, they offer the best current hope in closing the "capacity gap" as it becomes sufficiently critical to threaten brownouts in certain parts of the country. With all this (and more) as background, we felt confident with a detailed analysis that showed gas supplying nearly one-sixth of the primary energy used in generating electricity by 2010. This alone would require about 6 trillion cubic feet of gas annually, or more than twice as much as is being used now by the electricity industry.

The new transportation role we postulate for gas lies more in a series of pinpoint targets—the so-called "fleet" markets, especially in regions where it will continue to be difficult to meet air-quality standards.

Natural gas has been used on an experimental basis for two different types of vehicles—those that carry cylinders of highly compressed gas as fuel, and those that can substitute methyl alcohol (methanol) for gasoline in somewhat oversized, but more-or-less conventional tanks. Theoretically, methanol can be manufactured from coal or vegetable matter; but it will be a very long time before its unsubsidized production from either of those feedstocks can match the

Industry and Vehicle "Niches"
Complement Generation Market;
Tossup Seen in Cooling

economics of using natural gas as a chemical base. However, in this study we calculated only the effects of employing CNG vehicles on a large scale, because (paradoxically) their proportional demand for natural gas is somewhat smaller than is required in the overall methanol cycle and we wished to be conservative in estimating the potential market for gas in 2010.

Whether CNG or methanol eventually becomes the gas-based fuel of choice as an alternative to oil-based products in road transportation, it will probably enter the market first on a broad scale via specialized vehicles rather than ordinary private autos. An ongoing DOE study has alluded objectively to some of the reasons behind this in the preliminary reports it has issued, but they boil down to the following: the size and weight of tankage (which is easier to accommodate in larger vehicles); greater capital cost (which fleet owners might absorb more readily in anticipation of longer-term benefits); and the need for convenience in having places to refuel while a general distribution network is evolving (something many fleet owners are capable of providing for themselves). It is worth adding that essentially the same ground rules will apply to commercial penetration of the transport market by electric vehicles—which must still be considered prospective competition for gas-based taxis, buses, and local delivery trucks.

The final demand model in this study assumed that no more than one private car in 20 would be using natural gas as its primary energy source by 2010 . . . and that CNG vehicles would constitute only one-quarter of the private fleets in the country. But at the same time it seemed realistic to estimate that 75 percent of all city buses might

have switched to CNG by then. With all else equal, the prospects of reducing local air pollution by this means can obviously have great appeal. And it would be relatively easy for an administration pledged to help preserve environmental integrity to specify that funds provided through the Urban Mass Transit Administration (UMTA) or any other federal agency be used only for less-polluting vehicles—with the exact choice to be left to local authorities.

With these assumptions, we judged through model runs that an extra 1.7 tcf of gas would go into the transport sector for motor vehicles each year by 2010. This would be in addition to 0.6 tcf of gas that would be required to operate pipeline compressors around the nation—a use that is already commonly tabulated in energy-consumption tables as an input to transportation.

The other big new "niche" markets that we could foresee for natural gas are in industry. Even a cursory examination of construction filings for cogeneration facilities suggests that gas is the most favored of all fuels for this process—in which the end-results are both usable heat and electricity. Furthermore, the secular trend nationally toward a less energy-intensive service economy might combine with improvements in efficiency to slow down industrial consumption of energy in general; but a combination of economic, security, and environmental considerations should make gas a stronger contender for industrial use in general.

Residential consumption shows less opportunity for gas-demand growth overall. Despite regional limitations now, gas is already supplying heat to more than 45 million of the nation's 88 million dwelling-units. In addition,

approximately 34 million American homes also use gas now for cooking. Although new home customers for natural gas will appear in some areas where they have been rare, many will be able to achieve the same results in the future by expending less energy of any sort. Improvements in the efficiency of gas furnaces, coupled with slow but continuing improvement in the average insulation of our housing stock, will tend to cut the gas requirements per residence. Microwave ovens and electric heat pumps also compete with gas (although gas-fired heat pumps have been under development for years and might make a dent in the future).

The biggest imponderable in future commercial gas demand will be space cooling. Much of the rapid increase in use of electricity during recent years (especially at seasonal peaks) has been for air conditioning; but the contest between gas and electricity in this arena is not over. Double-absorption cooling by gas is ready to pose a major challenge—as are very efficient engine-driven gas “chillers”; and this potential was factored into the various demand scenarios we considered. Again, however, we were conservative—assuming merely that targeted R & D could help gas to increase its share of the commercial cooling market from its current 6 percent to a still-modest 10 percent between the 1990s and 2010.

If this country increases its emphasis on natural gas, the actual fuel substitution that takes place will depend on the sectors in which switching or replacement goes on. That is one reason

why this study took such pains in dissecting potential demand growth.

In the scenario pictured on page 17, the nation would use approximately a million and a half barrels of oil per day less by 2010 than in the baseline case (although imports would be affected more than that because of a 600,000-barrel-per-day stimulus to domestic production). Slightly more than half of the oil replacement would be in motor vehicles, and most of the rest would be divided between industrial and electric generation markets. However, generators of electricity have already slashed their dependence on oil—relying on it for only a few percent of their total energy input in recent years (even after the price of oil plummeted in 1986). The baseline model for 2010 projected little oil left in that sector for gas to replace, but gas in combustion turbines would be substituting for some oil as well as coal. This fuel-switch would be dictated by economics, but only because the partial use of gas (either on a seasonal basis, in “co-firing” with coal, or both) is quite likely to be the most cost-effective way to meet environmental standards.

The prospect of using more natural gas for generating electricity does not eliminate the importance of pressing ahead vigorously in the United States with coal production or with R & D on more economical clean-coal technology. Even with the accelerated gas use we have projected for 2010, this country would be using approximately one-third more coal than it does now. With domestic consumption around 1.2 billion tons annually by then, export markets can be envisioned that might coax U.S. production into

**Natural Gas Could Replace
About 1.5 MMBD of Oil More
... And Augment Clean Coal**

Role of Gas In 1990s Might Switch Emphasis In Years That Follow

approaching a billion and a half tons. Because the national insistence on air quality is not expected to evaporate, better ways must be found to burn even high-sulfur coal acceptably. Mandating the use of "scrubbers" raises new environmental problems in itself (besides reducing efficiency and ballooning costs); but such technologies as fluidized-bed combustion hold out more hope.

The principal opportunity to expand gas use during the next decade is in supplying electricity.

There are relatively few days during the year when low "reserve margins" of generating capacity pose their most serious danger—and then only during the hours when customers' demand for power rises to a peak. Because air conditioning has such a voracious appetite for energy, the public tends to associate such problem periods with high summer; but the widespread use of electric heating in an area like the blustery Northwest makes for "winter-peaking" utilities there . . . and the popularity of electric heat pumps in the Mid-Atlantic States is moving their generation load-curves into a characteristic shape that has twin peaks—one in cold weather and one in hot.

Conventional turbine-generators fueled with natural gas have been used for some time as "peaking units"—expressly to meet occasionally very large demand. In this role, their relatively high fuel cost per kilowatt-hour (as compared with "baseload" steam-turbine plants) has not been too limiting. Nor has the fact that many of today's gas turbines might face technological problems if they were forced to operate continu-

ously on a year-round basis instead of serving for intermittent spells as needed.

The maximum electrical output of the largest "combustion turbines" (so-called because the high-temperature combustion gases themselves spin the turbine blades) is fairly small in relation to the customary baseload plant. This can be an advantage in an era of fiscal caution in meeting demand projections, however, because it means that capacity can be added in smaller steps. Because these turbines can be ordered from production lines with only a low capital investment, we expect them to be the quick choice of many utilities to protect safe margins of reserve capacity that are threatened during the 1990s.

Gas can also be burned under conventional steam boilers to generate electricity; and, in areas near producing fields, such systems can clearly be economical for base loads. But until the Powerplant and Industrial Fuel Use Act (FUA) was repealed in 1988, it had actually been against the law for years to build utility or industrial boilers using gas as a heat source. This outmoded restriction was motivated by the common view in the 1970s (since proved incorrect) that our country was on the verge of exhausting its domestic resources of hydrocarbon fuel completely. Elimination of the ban forms part of the "new environment for gas."

Combustion turbines are starting to play a different role too. Despite FUA, new gas turbines have been permitted . . . and, in fact, they have even been encouraged (in a way that may not have been foreseen by legislators) through the Public Utility Regulatory Policies Act of 1978 (PURPA).

One of the purposes of this act is to promote cogeneration (albeit outside the electric utility industry), but roughly half of the heat-and-electricity systems that grew out of the initiative are fueled by gas. And gas turbines have been especially favored because of their low-polluting features and their high *overall* efficiency when exhaust heat is put to use.

It is the efficiency factor that presages eventual use of improved combustion turbines for baseload generation. When exhaust heat from a gas turbine is used to operate an integral *steam*-based generating unit, the "combined cycle" system gets an eye-opening power payoff from its input. About 47 percent of the heat is converted into electricity—compared with efficiencies in the 30s for conventional steam plants.

More R & D might even help baseload layouts of linked combustion turbines fueled by natural gas to become a standard item. At present, their major prospective competition appears to be combined-cycle turbines fueled by gas that is synthesized on-site from coal—an integrated system that has performed well in limited testing. Yet some utilities have already announced plans to install only the turbine segment of such a system at first—which means that natural gas would be the initial fuel, presumably to be displaced only if coal gasifiers offered some recognizable advantage.

We can easily foresee gas demand in the United States growing in discrete stages over the next 30 years—with baseload generation gradually superseding gas peaking units in emphasis within certain areas, and the number of vehicles

based on natural gas fuel starting to grow sharply later on.

History has shown that market competition generally results in better products. Consumer choice is not inevitably based on price alone, but can accommodate a remarkable variety of divergent goals—based on individual perceptions of needs.

America's energy requirements for the future involve security of supply, convenience, and the preservation of a safe, healthy, wholesome environment. Natural gas certainly can do more than "conventional wisdom" now says it is likely to do in satisfying energy needs across the board; but we believe that it would be a mistake to order—or simply subsidize—gas use. Therefore we have assumed in our modeling that free choice among fuels (or ways of using specific fuels) will be allowed to prevail. City bus systems would decide for themselves whether the low-polluting vehicles they buy with UMTA money should use CNG, methanol, chemical batteries, or some sort of exhaust-collection devices. Building owners would certainly choose on their own between cooling by electricity or gas. Those who generate electricity (for their own use or for sale) would not be *directed* to use scrubbers as the only allowable method of controlling emission levels—any more than they would be *forbidden* to use any particular fuel (even oil).

The only purpose in targeting R & D (largely through cooperative ventures with the private sector) toward certain *gas*-using technologies would be to make sure that certain useful and

**Policy Recommendations
Stress Broader Choice,
But Let Users Decide**

practical options we can now envision will be available *in time to make a difference*. The available choices should be broad.

Obviously, the same principle can be applied to an assumption we made about deliverability of gas. More than a century ago, the federal government helped in a number of ways to build railroads where none had ever existed; but today, ironically, the inverse is true for gas pipelines. Far from facilitating the creation of a new transport and storage infrastructure, government has often been the principal impediment—through slow-paced regulatory procedures.

An enormous transmission and distribution network for natural gas already exists; and if potential demand is evident in areas that are not yet being served optimally, we are confident that private capital will be available to finance new pipelines. All the federal government needs to do is to see that *needless* barriers to construction are removed.

The exact way for FERC to expedite its own licensing procedures is up to FERC. We believe that this *can* be accomplished, and we have only assumed that it *will* be. Beyond that, its leadership by example might do wonders in affecting the speed of public utility bodies at the state level. Even if the only step in common were to arrange for state and federal hearings on pipeline construction applications to proceed *concurrently* instead of *consecutively*, we have ample anecdotal evidence that the improvement would be felt almost immediately.

Because of the structure of growing demand, it has been assumed that special consideration in the pipeline approval process might be given at least to regions such as the Northeast—where reliance on imported oil is particularly high and where last year's *Energy Security* report from DOE noted there will be a need for "new power supplies sooner than other areas."

What does gas "buy" us in terms of energy security? ... and at what cost?

By 1993, according to baseline projections, the United States could be importing half of all the oil used here. Given the distribution of oil-producing capacity around the world, this country and its allies probably will have to rely on the tinderbox region of the Middle East for much of that supply. The perils to energy security in that case have been well documented elsewhere; they are undeniable.

If all present policies continue, our baseline model projects that U.S. oil imports by 2010 would be approximately 13 million barrels per day—almost twice as much as ever before in history. Imports would then represent more than 71 percent of total oil consumption. Our modeling for "accelerated gas use" (which is only *one* possible alternative scenario) projected a reduction of almost 2 million barrels per day in those imports. Thus, greater emphasis on gas *can* offer greater security against possible energy disruptions in the future; but perhaps even this will not by itself allow us to breathe freely enough. About 66 percent of our oil use still would be tied to imports, and other policy initiatives probably would be needed. Yet it is hardly arguable that the nation should risk postponing some of the relatively easy and economical steps to facilitate larger use of natural gas, whose imminent contri-

bution to oil-import reductions can be demonstrated. Time is running, even now.

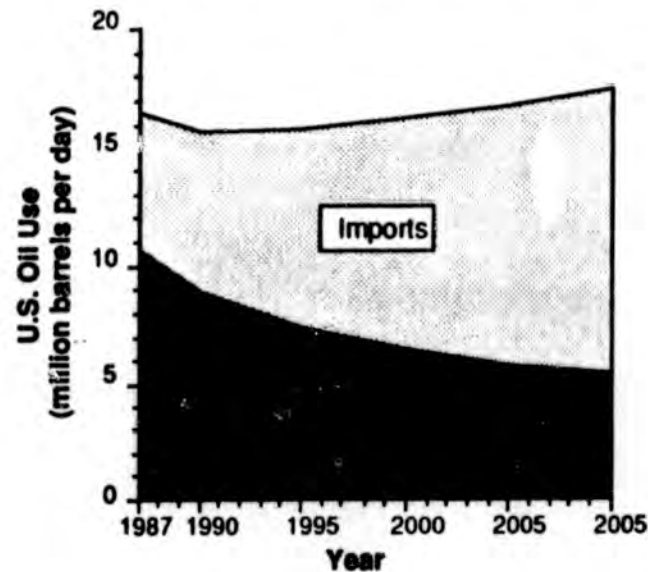
An oil glut exists today on the world market. With prices still low enough to keep our domestic drilling industry at an ebb, it may be hard for the public to focus on the fact that the international community's earlier rollercoaster rides in energy prices and energy supply could be repeated during the 1990s.

Cruel economic lessons of the 1970s have not been forgotten completely. Continued progress in energy efficiency and foreseeable fuel-substitution is expected to reduce oil's *percentage* share of the U.S. energy market. We see oil falling from around 42 percent of all energy consumption now to approximately 39 percent some two decades hence—even in the baseline case. If this seems like an excruciatingly slow pace at which to "back out" the fuel that has been the basis of what once was called "The Energy Crisis," remember that oil accounted for 47 percent of the nation's energy use in 1973. Fairly heroic measures have been taken since then, notably in a consumer revolt that amazed most economists after crude oil prices briefly hovered close to \$40 per barrel. The preceding section of this report gives some inkling of how imaginative and perseverant one must be to replace *additional* oil in an economy of

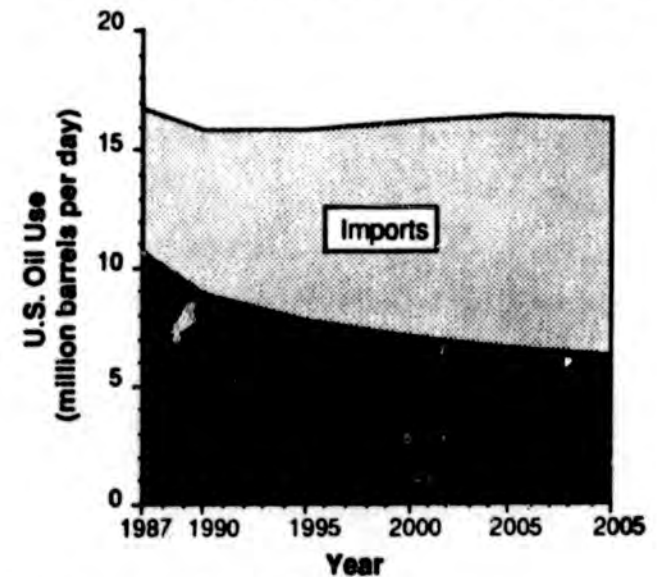
**U.S. May Be Vulnerable
To Energy Pressures
Again Before 2000**

Two Projections of Demand for Oil in the U.S. Economy:

a. following the present course



b. with this report's assumptions about modest moves to accelerate gas supply



Anything that permitted still greater reliance on alternatives to oil (including coal, nuclear power, renewables, and improved efficiency) might lessen imports in an extension to case "b." But additional problems in taking full advantage of such sources as coal and nuclear energy would compel even higher imports.

U.S. size. Almost 6 out of every 10 barrels of oil we use go into transportation—with the greatest portion of that devoted to fueling about 160 million autos and light trucks.

Even with the "oil fraction" on its way down, our growth in population, road fleet, and GNP seems destined to force an increase in the total amount of petroleum products we use. For this

reason, it is important to consider two other ways in which bolstering natural gas production helps to guard against oil problems we can see on the horizon:

- We have already noted that oil and gas are often found in the same geological formations. Intensified exploration for one aids discovery of the other. Part of the cuts in oil

imports we project comes from the growth in domestic oil output that would accompany more emphasis on natural gas.

- Besides producing the "dry" gas that winds up in statistical tables and pipelines, natural gas wells and processing plants are the source of "natural gas liquids" (NGL). These can be used ultimately in place of various products that come principally from the refining of crude oil; and they already underlie about 10 percent of our national supply of such products.

Historically, a great strength of the U.S. economy has been a resource-endowment that was rich in the nation's premier fuel. At first this was wood, and then in the 19th century it switched to coal. For several generations it has been oil. Domestic producers have been much more thorough to date in tapping oil resources than they have been in taking advantage of gas, so production of the latter fuel retains some growth potential while the former will be hard pressed to hold its own. At some time in the 21st century, this nation may complete another energy transition, entering the post-hydrocarbon era. However, our study of renewable-energy technologies has led us to believe that their growth will not be rapid enough to permit them to "take over" the national energy-consumption infrastructure as early as 2010. Meanwhile, it is important to develop resource strategies that can sustain growth and protect both economic security and foreign policy interests.

One of these is already the Strategic Petroleum Reserve. The fact that it has not been called upon

tends to point up its efficacy rather than to diminish the justification for its existence. Surely the 550-million-barrel-plus SPR (and its counterparts in other countries) relieved some apprehensions during the Iran-Iraq War and provided a bit more freedom of action in dealing with threats of oil cutoffs. There was also a time in the recent past when the Organization of Petroleum Exporting Countries (OPEC) was quite successful in its short-term efforts to manipulate prices by mutual agreement among suppliers. The availability of reserve crude oil that could enter the U.S. market during any period of adjustment to an emergency discourages any consortium of suppliers from trying to wield economic power again in a way that is openly hostile to our interests. The same reasoning explains why it is advantageous to develop natural gas supply as an alternative to imported oil (via the possibility of fuel-switching).

The major danger we foresee now lies at some indeterminate point in the future when OPEC has recovered enough of the global market so that approximately 85 percent of its own oil-production capacity is being called upon to satisfy world demand. By an historical rule-of-thumb, this is when such a quasi-cartel is sufficiently emboldened to take drastic actions—raising prices sharply, withholding supply, or a combination of the two in an effort to squeeze maximum rewards for its product from customers who have little other choice.

Even in the "accelerated gas use" case, it may be almost impossible to avoid such a new confrontation forever. On a worldwide scale, our computer projections show OPEC delivering on the order of 35 million barrels of oil per day by 2010—

**Alternatives to Oil
Reduce Cartel Incentives
To Squeeze Down Supply**

fully twice as much as today. But postponing what now appears to be inevitable is not an idle exercise. And the difference in U.S. gas consumption for 1995 between the two cases we present in this report is a hefty 1.5 tcf—the equivalent of some 750,000 barrels of oil per day. Between now and then, the policy options we assumed appear to double the prospective growth for natural gas.

As to dollar costs, this depends on whether they are viewed in a narrow or a broad context... in the long term or the short run. For instance, a 10-percent tax credit for exploration might directly reduce immediate government revenues by about \$350 million annually. But the benefits to the whole economy (not to mention the ultimate increase in federal and state royalties for producing wells on government-controlled lands) would balance this expense within the first three years. This is covered more fully in the section of the report that begins on page 34. But the most important response to questions about the cost of these moves toward greater energy security is that they should, in all fairness, be balanced against other benefits as well (improved trade balances, environmental protection, and so forth). The quest for energy security is not the only reason for this country to swell its supply and

use of natural gas; in some quarters it probably is not even the chief one.

One of the more novel ideas that emerged during our study was a proposal that the nation's program for a Strategic Petroleum Reserve be broadened to include the largely decentralized storage of natural gas as well. Because demand for gas is highly seasonal, the dollar-wise impulse to utilize pipeline capacity to its fullest has led to the creation of a vast number of underground reservoirs—usually quite near consumption centers, but invisible to customers. Given the substitutability of natural gas for oil, we questioned whether it might not be cost-effective for the Department of Energy to lease such space and fill it with purchased gas as an additional buffer against price shocks or supply problems in oil.

Certainly this is one concept on which instant consensus within the gas industry itself is impossible. Producers, transporters, and distributors of gas have differing viewpoints. Like the prickly question of how to settle old "take-or-pay" contracts, the possibility of an SGR was not addressed specifically in our modeling. Yet we raise the notion in this report because we believe it is worth being subjected to further critical analysis.

How much can natural gas do for environmental quality?

Natural gas can do even more for the cause of clean air in this country than some of its proponents say it will. It depends a lot on how conscious we are as a nation of how various types of atmospheric pollution take place.

In coming to grips with the problems of airborne pollutants, there has been too much preoccupation with "percentages" or "tonnages of emission reductions" (often "determined" theoretically), as distinguished from real *results in improved air quality*. Sometimes there has even been a stubborn, counterproductive insistence on specifying the *way* emissions should be curbed.

The nation would be better served if performance standards replaced attempts to dictate compliance technology in environmental-protection efforts associated with the production and use of energy. We assumed such a policy orientation in our model—which paves the way for more use of natural gas and, incidentally, an even greater-than-proportional set of benefits to the environment. We also resolved to dig deeper than the obligatory (but essentially misleading) sort of observation that "the use of so-and-so-much natural gas will reduce the atmospheric burden of sulfur dioxide by so-many tons, as compared with Fuel X."

Most people realize that natural gas is a clean-burning energy source. A table on the following

page shows abstractly how it compares with typical samples of coal and oil. This alone is sufficient to show that environmental improvements will hang in part upon whether gas is being substituted for oil or for coal. However, there are other variables as well. Timing and placement of the fuel-substitutions are equally important in the long run.

Professors James A. Fay and Dan S. Golomb, of the Massachusetts Institute of Technology, have produced an excellent analysis, "Natural Gas and the Environment: Benefits for Air Quality," which is one of several reference documents being circulated in conjunction with this summary report for those who are interested in more detail. Even to treat the topic in brief, however, it seems desirable here to explain five general types of environmental effect that arise in part from burning fuels:

- **Acid Deposition**—which goes beyond the familiar shorthand term ("acid rain") to include snow, hail, dew, and even dry deposits of acids that may be formed in the air from the interaction of sulfur and nitrogen oxide emissions with atmospheric oxidants (including ozone).
- **Ozone at Ground-Level**—which has nothing to do with the potentially dangerous lack of ozone in the upper atmosphere, but

**Environmental Value Depends
On Which Fuels Are Replaced,
When, Where, and How**

Comparative Pollution From Uncontrolled Burning of Gas, Oil, and Coal
(using emissions from gas as the standard)

<i>Pollutant</i>	<i>Gas</i>	<i>Oil</i>	<i>Coal</i>
Sulfur dioxide (SO ₂)	1	1000-3000	3000-8000
Nitrogen oxides (NO _x)	1	2	4.5
Small particles	1	20	250
Carbon monoxide	1	1.5	1.5
Carbon dioxide	1	1.25	1.7
Reactive hydrocarbons	(There are virtually no emissions of this type from natural gas. Emission from oil is about twice that from coal.)		

instead is a problem because *concentrations* of this toxic variant of ordinary oxygen can harm plants and cause respiratory diseases when breathed. Ozone is one of the ingredients of smog. It builds up as sunshine works on nitrogen oxides in the presence of reactive carbon compounds (such as gasoline fumes and partially burned gasoline).

- **Carbon monoxide**—a toxic product of incomplete combustion, especially from vehicles. This gas is one of the precursors of ozone.
- **Particulates**—the tiny bits of matter suspended in the air (including soot, fine ash, and assorted kinds of dust and dirt) that turn clear skies into haze and are linked to various health problems.

- The “**Greenhouse Effect**”—a long-range phenomenon of slowly rising temperatures worldwide under a blanket of some pollutants (based partly on a general increase in fuel-combustion of all kinds) that has attracted broad attention recently.

In some cases the pollution effects are not limited to the immediate vicinity of emissions, and in many cases the adverse effects that have been observed come from more than one pollutant.

“Acid rain” is derived largely from sulfur dioxide (SO₂) and nitrogen oxides (NO_x)—especially in *hot, sunny weather* if oxidants are abundant. In eastern North America, there is a sharp peak in atmospheric acid generation between June and August. Ozone forms when NO_x and

hydrocarbons (HC) react together chemically in *sunlight*—particularly on warm, breezeless days. And most of the visibility-blocking haze from particulates also occurs in *summer*.

Perhaps half of the gas-accumulations that give rise to fears about the greenhouse effect consist of carbon dioxide. To produce a given amount of heat, natural gas emits almost 50 percent less of this compound than coal and 20 to 30 percent less than oil. Furthermore, the higher conversion efficiency of gas-fueled combined-cycle turbines promises an additional advantage when CO₂ emissions are related to output of electricity. However, there is a fair body of scientific opinion that "global warming" could regulate itself in various ways; and the emissions that tend to promote it are not all tied to energy production and use. This may not be as strong or independent a talking point on behalf of gas use as some have assumed.

It is obvious that extra substitution of natural gas for other fuels during the summer months would go most directly to solving many pollution problems that exist. To give a concrete example, a typical 500-megawatt oil-fired powerplant releases some 70,000 tons of sulfur dioxide annually. Replacing oil with gas *for the six months between April and September* (when gas prices drop in many regions anyway) would cut the *annual* output of SO₂ to 35,000 tons; but, because acid formation normally speeds up during those months, the *effect* would be the same as if it had been cut to only about 17,500 tons year-round.

Fortunately, this approach would dovetail with the traditional seasonal lull in U.S. consumption

of gas (which is still used in the residential and commercial sectors primarily for heating). The pipeline network nationwide is less than four-fifths full of gas during summers now—with regional rates of capacity utilization ranging from 51 to 93 percent.

Fay, Golomb, and others have also pointed out another sort of environmental bonus from selective use of gas. Some equipment permits the burning of gas simultaneously with either coal or oil. In such "co-firing," the combustion with gas actually "scavenges" some pollutants that result from burning the other fuel. Some tests showed that substituting gas for only 20 percent of the heat value of coal or oil in an installation reduced NO_x emissions by 60 percent.

In the case of generating plants, replacing coal or oil with natural gas in actual practice appears to be able to reduce the production of sulfur dioxide in almost direct proportion to the percentage of gas used. On balance, replacing half of the heat value of coal that contains 1.2 percent sulfur with gas will lower SO₂ emissions from 2.5 pounds per million Btu's to about 1.2—which happens to be the rate targeted in most "acid rain bills."

Pollution control is a complex process. Its effectiveness usually depends on local circumstances, and its economic rationality almost always does.

A recent examination of several hundred diverse eastern powerplants came to the conclusion that the very same reduction in acid rain that might result from ordering all of them to install flue-gas desulfurization equipment ("scrubbers") would be achieved—at *less cost*—by switching

Selective Substitution Of Natural Gas Offers The Maximum Benefits

**Requiring Air Quality
Results Is Wiser Than
Telling How to Comply**

from the present fuel (either coal or oil) to gas during the summer half-year.

Lest this encourage a move to *order* that approach universally, it should be added hastily that gas-substitution is not always the best answer either. First, the costs of capital investment, fuel, and plant operation must be evaluated for each of many possible options. The older a facility is, the less worthwhile it is to install the prodigiously expensive scrubbers—which are also costly to operate (because of their complexity, the net-power-loss they involve, and the sludgy wastes that may be generated by hundreds of thousands of tons at a single site). But it also costs some money to convert an oil-fired or a coal-burning plant to make it compatible with natural gas—whether this is done by altering the boilers in place or through providing new side-by-side equipment. Adapting the same system to use *either* of two fuels (or both at once) generally lowers heat-conversion efficiency too—although performance often improves when natural gas replaces either coal or oil, while maintenance becomes easier.

Trade-offs among all the competing technologies that might produce acceptable results in air quality (whatever standards are to be maintained) can best be determined by the operator involved. This also explains why the “bubble concept” and trading of “emission credits” make sense when compliance with environmental standards is being monitored. Under the former, an industrial or energy-producing complex is judged on the basis of the total emissions it adds to an area—rather than by evaluating each of its components individually. With “credit trading,” an

entire installation that gains “points” by reducing emissions more sharply than regulations require is permitted to sell certain emission “rights” to a nearby operation when this might enable the second owner to adopt a cost-saving practice that otherwise would be just beyond the stipulated emission limits.

Without question, both principles could be extended to environmental improvements that come from *selective* switches to natural gas. Both promote competition in finding the best *overall* solution to inevitable pollution dilemmas in the future. By contrast, the “conventional wisdom” that underlies energy-use projections like the one we created in this study as a “base case” are blind to reality: The *baseline of emissions* is fated to rise so long as more energy must be produced and consumed in any way.

Stationary sources of pollution (such as powerplants, factories, and other buildings) are not the only contributors to acid rain, ozone buildup, and dirty air. According to the interim report of the National Acid Precipitation Assessment Program issued earlier this year, for instance, more than one-third of the NO_x emissions in this country can be traced to highway vehicles—with other forms of transportation adding another 10 percent. Here once again, a generalized comparison of fuel emissions such as appears in the table on page 30 does not tell the whole story. The latest information about the conversion of gasoline- or diesel-fueled vehicles to compressed natural gas shows that this can *slash* emissions of carbon monoxide and reactive hydrocarbons. Even if widespread use of natural gas vehicles (NGVs) were limited mainly to *fleets* in metropolitan areas, it would at

least give many cities a fighting chance to comply with national ozone standards. As things stand now, Los Angeles fails to meet requirements on ozone-limitation almost daily throughout each summer.

In all, as of June 1988, 341 U.S. counties failed to meet requirements of the Clean Air Act for ozone. Many fell short of compliance in regard to one or more of the other major pollutants in question too: 129 for particulates, 127 for carbon monoxide, 49 for SO_2 , and 4 for NO_x . More urban

areas will soon fall below various legislated lines unless significant new measures are undertaken. *Something must be done!*

Methanol (derived from natural gas) is another vehicular fuel that would reduce some emissions. For instance, its use gives off less NO_x than gasoline does; and with certain engine adjustments it also cuts carbon monoxide. As explained earlier, however, we limited the single composite "model" we present here to CNG conversion only.

What are the implications for budget, overall growth, and international affairs?

**Taken as a Whole
The Program Is Affordable
—Even in Frugal Times**

The first question when any fresh policy surfaces in Washington this year is: "What effect would it have on the budget deficit?" Because we considered this constantly as we built and polished the assumptions for the accelerated-gas-use model that wound up being described in this report, we are able to respond with confidence: "Little net difference in the short run, but with budgetary benefits increasing steadily in future years."

Perhaps the secret to this welcome finding of fiscal responsibility in WEFA's searching computer analysis is that the situation we postulate is not a "program" in the same sense as an effort to accomplish a specific mission in space, or to develop a broad array of synthetic fuels, or (all by itself) to chop oil imports to an absolute minimum. Instead, it is a composite of many, small governmental handholds and nudges that use the leverage of private-sector motivations to progress incrementally toward certain goals that everybody agrees we must seek—cleaner air, less dependence on unreliable oil supplies, a better trade balance, a healthy employment outlook at the national and regional levels, and so on.

The model is comprehensive enough to integrate any results that can be expressed unequivocally in dollars and cents. Obviously there are some pluses and some minuses, as represented

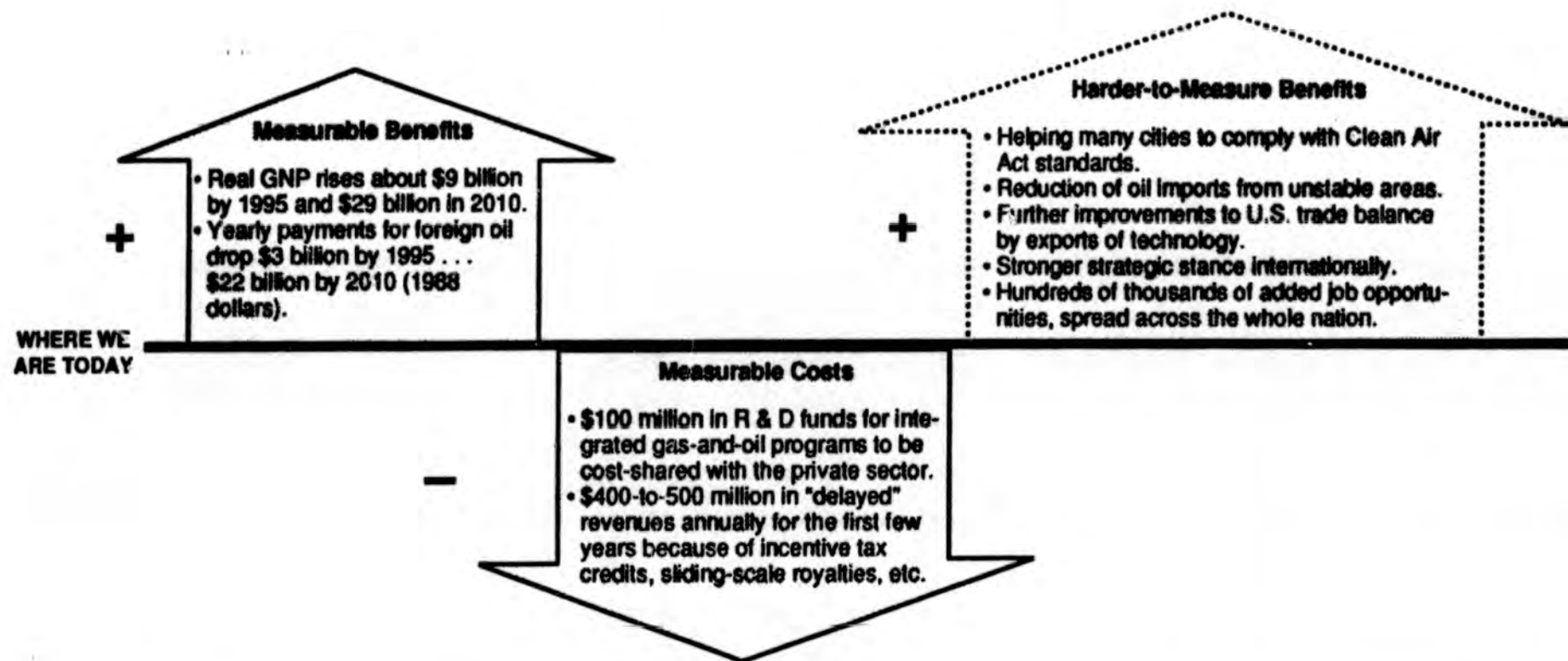
graphically on the opposite page. One implicit factor in the equation, however, consists of benefits whose cash value is real but imprecisely perceived. These are listed in the arrow on the right-hand side.

For instance, if the needed improvements in energy security we enumerated earlier in this report are not achieved by producing and using more natural gas, it is a cinch that their achievement by other means will add costs somewhere else in the budget. The same goes for the nationwide commitment to bring air quality into compliance with the law.

The largest single direct annual cost among the policy options appears to be for tax credits on exploratory and redevelopment drilling. But within two years after enactment of the tax credit the WEFA model indicates that the federal budget deficit would actually be reduced by almost \$1.4 billion because of revenues collected on business activity and wage payments that would not have occurred otherwise. Our analysis on the basis of output-per-well indicates that each additional redevelopment well, involving some \$20,000 in tax credit, would make about a billion cubic feet of additional gas available for production over a 10-15 year period. Such results would clearly stimulate the industry to make continuing investments in the process of recovering "bonus

Generalized Cost/Benefit Balance of the "Accelerated-Gas-Use Case"

(all dollar costs are in 1988 equivalents)



gas" that had been bypassed in older fields because of less complete knowledge earlier about reservoir patterns.

Thus, although a 10-percent tax credit for exploration drilling would be portrayed as an immediate cost to the Treasury of \$350 million through lowered revenues, the program should

actually *enhance* federal revenues in a very short time. Our soundings of the industry confirm the model results, but lead us to doubt that much investment will be made at all on additional exploration and redevelopment in the immediate future (while energy prices remain very low and the demand for gas is "soft") without some such

stimulus. Aside from additional royalties the government would receive in any case where such "new-found" gas is produced from federally controlled well sites, an offset on the positive side would come from increased economic activity throughout the surrounding region. Because many areas suitable for redevelopment drilling are now depressed, the social benefits as well as the economic ones (including greater tax revenue from job-income and supporting business) should be considered when evaluating the proposal.

It ought to be kept in mind always that there is a symbiotic relationship between gas supply and gas demand . . . and among many elements of the policy options in this or any other alternative scenario. Eliminating a single piece of the picture (such as the redevelopment credit) might not destroy the entire image, but it would stand a good chance of distorting it unless another initiative with the same net influence were substituted.

In "big picture" terms, this set of policy assumptions yields strong positive results. Gross national product is bumped upward slightly—from \$6,855 billion to \$6,884 billion (in current dollars) by 2010. The U.S. trade deficit is improved too, even in the shorter run, because of lower oil imports—with the differential amounting to \$1.4 billion in 1995 (in current dollars), and rising to nearly \$24 billion by 2010. By then, the lowering of U.S. demand for imported oil by about 2 million barrels per day would produce some reduction in the world oil price too, providing some economic benefit; but we estimate that this would only amount to pennies per barrel.

The rise in GNP we project is a result of many factors and touches many parts of the economy.

Producing additional steel for an expanded pipeline network, as well as "pipe" and "tubulars" for the oil and gas wells themselves, creates jobs in what has sadly been dubbed the "Rust Belt." Expanding new gas fields where the industry might otherwise be moribund adds work in Appalachia. (Incidentally, the steady rise projected in demand for coal—even though at a lower rate than in the baseline case—shows clearly that this companion energy industry is also likely to have an expanding rather than a contracting payroll overall.) In net total, the additional economic growth was projected to add some 374,000 jobs by 2010.

Productivity and competitiveness are other vital criteria these days, and the more efficient development of U.S. resources in the "accelerated-gas-use case" is among its pluses. It has been estimated that our technology in extracting natural gas from the earth improves by perhaps 2 to 3 percent per year (although this change is masked by larger fluctuations in drilling costs). Thus, even in the base case, we projected that this country would be able to lower its current-reserves-to-current-production (R/P) ratio from 10.2 to 8.2 by 2010. With additional R & D and the entire new environment for natural gas, analysts involved in this study suggest that this ratio could approach 7.0 in the United States, thereby improving production economies.

World reserves of natural gas represent more than 3,600 quads, but less than 2 percent of that base is now being produced annually. Besides the U.S., the six countries that are known to have natural gas reserves of 100 quads or more each are Canada, Iran, Norway, Qatar, Saudi Arabia, and the Soviet Union.

Exports of new U.S. technology for geoscience and the extraction of hydrocarbon fuels also can help in closing our trade deficit to some extent, but worldwide growth for natural gas promises benefits on its own to this country.

A multinational tilt from oil toward gas would make the global energy market more stable. World reserves of natural gas are comparable to those of oil, but they are dispersed more widely. About 58 percent of all oil reserves are concentrated in the Middle East, but only 26 percent of the gas reserves lie there. Industrialized nations (the major users of gas, now and in the foreseeable future) control only 16 percent of those oil reserves but 57 percent of the gas reserves.

Nor is this a case of boosting the "haves" against the "have nots." Many populous, less-developed countries (among them Mexico, Venezuela, Argentina, Pakistan, Thailand, Nigeria, Indonesia, and China) have large natural gas resources that can be tapped more assiduously to satisfy their growing domestic needs for energy. Their broader use of low-polluting fuel is especially desirable in the face of environmental problems that can also be expected to increase as their transportation networks proliferate and industries connected to higher living standards expand.

Japan is a special case among nations. It has virtually no indigenous energy sources, and it already has contracts to bring in large amounts of liquefied natural gas from Indonesia, Alaska, Brunei, Australia, and Abu Dhabi. By the turn of the century it might add the Soviet Union and Nigeria to this list and Japan could also negotiate

with China for natural gas supplies at some future date. (The U.S.S.R., which itself consumes about one-third of all the natural gas produced in the world each year, contains approximately 40 percent of the earth's reserves.) Japan is concerned about air pollution and might determine to put great stress on gas as a transportation fuel, as well as a heat source in generating electricity.

Western Europe is scheduled to become a closer economic unit in the early 1990s; and, considered as such, it has 220 quads of natural gas reserves—with considerable potential from the Norwegian fields in the North Sea. At present, Western Europe imports gas from the U.S.S.R. and (via a pipeline under the Mediterranean) from Algeria. LNG imports from Nigeria may also begin to serve some parts of Europe within a decade or so, but its own gas production could be encouraged further. We believe that gas use there could grow safely by about the same rate as the one we projected in this report's "accelerated" case.

The "new environment" for natural gas is upon us—here and throughout the world. In this country, producers, transporters, distributors, and consumers have finally begun to look for mutual interests rather than to focus on what divides them. A new President-elect and a Congress controlled by the opposing party at least seem to have common goals. In mid-1989, a ministerial meeting of the International Energy Agency (IEA) could well begin to explore cooperative efforts to grasp the environmental, security, and economic advantages natural gas offers. The time is ripe to put priorities and policies in order.

**U.S. Leadership Can Help
Develop Wholesome Role
For Natural Gas Worldwide**

How This Study Was Conducted

When policy goals are separated from real-world *possibilities*, the results may be frustration and disappointment. Industry and government filing cabinets are replete with "wish lists" that never become more than that.

The principals of Washington Policy and Analysis sensed a formidable and rapidly growing national consensus on the multi-faceted promise of natural gas for the rest of this century and into the next. But they recognized the disturbing reality that the fuel's supply and demand in this country were both still being projected at a level that meant major potential benefits in environmental protection and greater energy security might not be realized.

A country this size does not usually change energy trends quickly except in response to a trauma, so we knew it made sense analytically to try to push our vision as far ahead as we could with rigor. The WEFA Group (newly formed in a merger of Wharton Economic Forecasting Associates and Chase Econometrics) had excellent tools to do the job and the ability to focus them simultaneously on a single task: a) its World Forecasting Service (which would be essential because of interrelationships between the United States and world markets; b) its Long-Term U.S. Macroeconomic Model; c) its gas and oil supply model; and d) its model to coordinate supply and demand for all U.S. energy sources.

We formulated conceptually the questions that had to be answered by integrated computer simulations for the years between now and 2010, then authorized WEFA to begin. Our baseline followed the reference case published by that group in July 1988. To evaluate the practical possibilities of

putting greater emphasis on gas, we injected and tested a series of assumptions in components of the model that were controllable variables. We were open to change, but also kept our eyes open to federal budgetary caution as well as to real political limitations and to the recent history of tensions among various segments of the natural gas industry itself. We tried to postulate an alternative situation that would be at least a framework for future discussion and eventual consensus. For instance:

On the supply side, we

- incorporated assumptions about a broader gas reserve base that grew out of a Department of Energy study published in the spring of 1988 (which was reinforced independently by the latest industry estimates);
- weighed the possible effects of federal R & D support that targeted, for example, the geosciences relevant to hydrocarbon deposits (a slight shift in policy emphasis that would probably be reflected in changes to the R/P ratio for natural gas—total reserves divided by annual production);
- gauged the results of tax incentives for exploration and production rather directly—because these modify returns on investment all along the line;
- considered the great progress made over the past eight years to free up energy trade on both sides of the border between the United States and Canada—even apart from the U.S.-Canadian Free Trade Agreement (whose aim in this instance was mainly to consolidate formally an already healthy set of working arrangements);

- incorporated production of "unconventional" supplies of gas from coal seams, co-production, and Devonian shale that would be available as a result of technological improvements based on research efforts; and
- added the potential for more development of gas on the North Slope of Alaska.

These assumptions, coupled with our price assumptions, provided us with an upper ceiling for available gas supply. Professor Robert Finley, of the University of Texas at Austin, reviewed the initial gas supply profiles that were produced to ensure consistency between the econometric results and geologic reality.

On the demand side, we

- adopted the basic WEFA projections for GNP and oil price;
- adjusted exploration and production levels for both gas and oil to reflect increased drilling, allowing the WEFA model to calculate the full effects on U.S. economic activity;
- developed assumptions about the industrial penetration of advances in end-use technol-

ogy, in consultation with Professor Robert Williams, of Princeton; and

- incorporated assumptions regarding "least-cost" strategies for reducing emissions to meet air quality standards (with the assistance of Professors James Fay and Dan Golomb of MIT, and David Bardin).

We compared baseline outputs with runs on the "accelerated-gas-use" scenario and noted the resulting differences in fuel-mix and trade balance over the projected time span. Then we examined the variations in order to estimate the environmental implications.

Finally, the WEFA Long-Term U.S. Macroeconomic Model incorporated all the changes in the energy sectors and the trade sectors of the economy, as well as the fiscal policy aspects of the "new gas environment," to generate the impacts that might be anticipated on the economy as a whole (GNP, employment, deficits, and so on). The results were compared with the baseline to measure the effects of the changes.

Natural Gas: Resources and Producibility. William L. Fisher, Bureau of Economic Geology, University of Texas at Austin.

Natural Gas and the Environment: Benefits for Air Quality. James A. Fay and Dan S. Golomb, Massachusetts Institute of Technology.

Advanced Gas Turbines for Power Generation. Robert H. Williams, Center for Energy and Environmental Studies, Princeton University.

The Role of Natural Gas in Energy and Environmental Policy. David J. Bardin, Arent, Fox, Kintner, Plotkin & Kahn, Washington, D.C.

Natural Gas: A Strategic Resource for the Future. A Tabular Comparison of the Baseline and "Accelerated-Gas-Use" Cases Modeled by the WEFA Group.

**Technical Papers Associated
With This Study**

Two Possible Futures for U.S. Gas Supply

Baseline Case—The Present Course (tcf)

	1990	1995	2000	2005	2010
Lower-48 conventional gas	15.8	15.8	15.1	14.9	15.5
Associated	3.3	3.1	2.8	2.6	2.5
Nonassociated	12.5	12.7	12.3	12.3	13.0
Imports	1.4	2.1	3.2	3.4	3.3
Canada	1.3	1.6	2.3	2.5	2.4
Mexico	0	0	0.1	0.1	0.1
LNG	0.1	0.5	0.8	0.8	0.8
Unconventional	0	0	0	0	0
Alaska	0	0	0	0	0
Total tcf	17.2	17.9	18.3	18.3	18.8
Total quads	17.7	18.5	18.9	18.9	19.4

Alternative Case—Recognizing a "New Gas Environment" (tcf)

	1990	1995	2000	2005	2010
Lower-48 conventional gas	16.1	16.7	17.7	18.5	18.1
Associated	3.3	3.1	2.8	2.8	2.9
Nonassociated	12.8	13.6	14.9	15.7	15.2
Imports (total)	1.5	2.5	3.7	3.8	3.8
Canada	1.4	1.5	2.4	2.5	2.5
Mexico	0.0	0.3	1.5	0.5	0.5
LNG	0.1	0.7	0.8	0.8	0.8
Unconventional	0.1	0.2	0.3	0.8	1.0
Alaska	0	0	0	0	1.2
Total tcf	17.7	19.4	21.7	23.1	24.1
Total quads	18.2	20.0	22.4	23.8	24.8

**A Research Report
of WASHINGTON POLICY AND ANALYSIS
A MILLER & CHEVALIER CONSULTING GROUP**

If the United States is to take full advantage of natural gas as a strategic resource for the future, here is a sample of what might be done in 1989:

1. Expand federal funding for research and development on the geoscience that underlies natural gas production, especially in regard to enhanced gas and oil recovery. To limit federal outlays (and to make sure that the results are put to use broadly and promptly), this could be done with industrywide support through the Gas Research Institute or through cooperative ventures linking government, industry, and universities.
2. Expand federal funding and other incentives for R & D linked to gas-use technologies—including programs designed specifically to promote the commercialization and economical penetration of the market by new combustion turbines for the generation of electricity, cooling by gas, natural-gas vehicles, and the selective use of "co-firing" with gas and other fuels.
3. Identify the onshore and offshore federal lands that are attractive targets for environmentally sensitive exploration and production, and make them more accessible to the private sector.
4. Enact a program of limited tax incentives to encourage domestic exploration for gas and oil and redevelopment drilling in older fields.

5. To take full advantage of new promise from geoscientific knowledge about hydrocarbon deposits that have been bypassed or untapped, institute a 10-percent tax credit for redevelopment drilling.

6. To clarify the ground rules for most future investment, enact complete decontrol of wellhead prices for all gas.

7. Promote a "least-cost" strategy for reducing the emissions of pollutants from energy's production and use, by implementing environmental regulations that are based on performance (for example, by favoring such low-cost options as trading emission "credits," burning gas in conjunction with other fuels, and having compliance monitored in terms of areawide "bubbles" rather than individual facilities).

8. In areas where environmental standards are not being attained, make sure that federal funds provided to local government for vehicles are used exclusively for low-polluting equipment.

9. Use all environmentally responsible procedures at the federal government's command to expedite the licensing of new capacity for pipeline delivery of gas to the Northeast.

This is no "magic formula"; but it is at least a framework for executive and legislative discussion, in that it addresses both supply and demand. Concentrating on one without the other simply does not promise to change the outlook. A new attitude toward natural gas is emerging—in the U.S. and worldwide. But it will be thwarted by either a "business-as-usual" or a piecemeal approach.

Energy Analysis

1515 Wilson Boulevard
Arlington, Virginia 22209

A.G.A. Planning & Analysis Group
January 23, 1989

TRENDS IN ELECTRIC GENERATION CAPACITY AND THE IMPACTS ON NATURAL GAS DEMAND

Digest

Growth in electricity demand, coupled with reduced plans for new facilities, has brought into question the adequacy of electric generation capacity in the mid-1990s. Recent North American Electric Reliability Council (NERC) studies show that electric utilities have continually reduced the number of planned capacity additions over the past decade. In 1988, total planned additions were 73,400 megawatts (MW) or 71 percent less than the 250,000 MW planned for the 10-year period beginning in 1979. This is reflected in an 86 percent reduction in planned coal capacity and an 85 percent reduction in planned nuclear capacity additions.

The natural gas share of planned capacity additions is expected to grow. Today, planned natural gas-based generation additions comprise the largest share, almost 40 percent, of planned utility-owned capacity additions of 100 MW and larger. A relatively new source of generation capacity is non-utility generators (NUGs), that sell power to utilities. Current projections of NUG additions exceed the level of coal and nuclear additions. Projected NUG capacity has tripled from 6,600 MW in 1985 to 19,000 MW in 1988. More than half of all new NUG additions are expected to be gas-fueled.

If peak electricity demand grows at the comparatively low rate of 1.9 percent annually between 1989 and 1997, as projected by NERC, then an additional 50,000 MW of generation capacity will be required in addition to the 32,500 MW of capacity currently under construction. However, a more rapid demand growth rate of 2.9 percent annually for this period, conservative by recent standards, necessitates the additional construction of almost 105,000 MW beyond plants currently under construction, according to A.G.A. calculations.

Exhibit B

TRENDS IN ELECTRIC GENERATION CAPACITY AND THE IMPACTS ON NATURAL GAS DEMAND

Introduction

Currently, excess electric generation capacity exists in many parts of the United States. However, the recent growth in electricity demand, coupled with reduced plans for new facilities, has brought into question the adequacy of this capacity in the mid-1990s. In addition, it is important to consider what effect the increasing age of existing generation units will have on the future mix of generation equipment by fuel type. With no new nuclear units planned (beyond what is under construction) and about 14 percent of all coal-fired units expected to be 40-years old by 1997, the need for new capacity, particularly NUGs, has become likely.

The purpose of this analysis is to identify gas demand opportunities in electric generation. More specifically, trends in electricity demand growth and generation capacity additions are evaluated to determine the amount of new generation capacity needed to begin construction within the next decade and what share of this new capacity will be fueled by natural gas.

Executive Summary

- Recent NERC studies show that electric utilities have continually reduced the number of planned capacity additions over the past decade (see Figure 1).
 - In 1988, total planned additions were 73,400 MW or 71 percent less than the 250,000 MW planned for the 10-year period beginning in 1979. This is reflected in an 86 percent reduction in planned coal capacity additions and an 85 percent reduction in planned nuclear capacity additions.
 - Today, planned natural gas-based generation additions comprise the largest share, almost 40 percent, of planned utility-owned capacity additions of 100 MW and larger.
- A relatively new source of generation capacity is NUGs, that sell power to utilities. Current projections of NUG additions exceed the level of coal and nuclear additions. Figure 1 shows that projected NUG capacity has tripled from 6,600 MW in 1985 to 19,800 MW in 1988.
 - More than half of all new NUG additions are expected to be gas-fueled.
- As shown in Table 1, the most recent (October 1988)

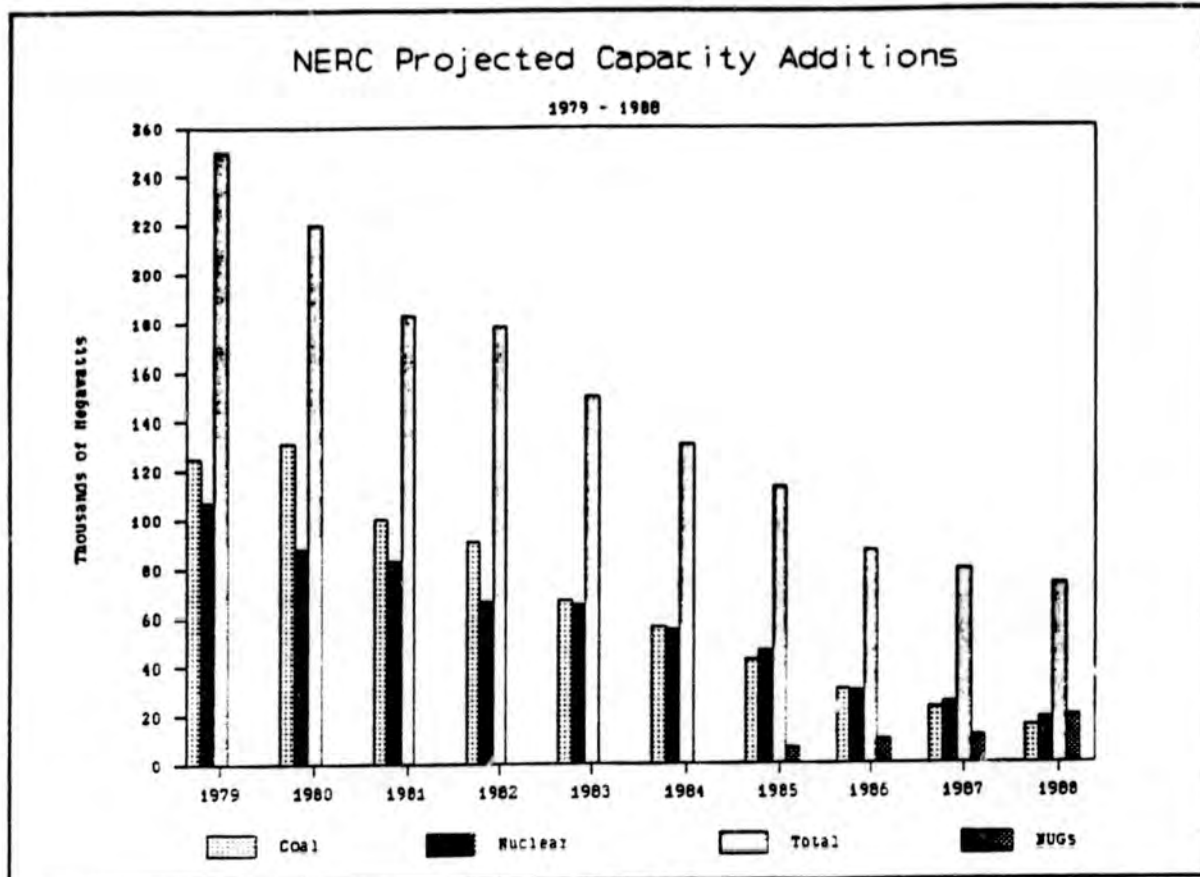


Figure 1

Table 1

**A.G.A. Estimated Capacity Shortages in 1997
Beyond Current Construction
(Megawatts)**

REGION ¹	A.G.A. Base Demand Growth Case (1.9%/year)	A.G.A. Rapid Demand Growth Case (2.9%/year)
ECAR	0	4,991
ERCOT	14,276	21,339
MAAC	3,528	6,785
MAIN	2,955	5,971
MAPP	430	2,533
NPCC	5,637	10,711
SERC	11,904	27,052
SPP	2,941	9,406
WSCC	8,080	16,038
TOTAL	49,751	104,826

¹See Appendix A for regional descriptions.

electricity supply and demand outlook published by NERC suggests that most regions could be experiencing electric generation shortages by 1997. This is based on the assumption that only those projects that are currently under construction, 32,500 MW, will reach completion.

- According to A.G.A., even if peak electricity demand grows at the comparatively low rate of 1.9 percent annually between 1989 and 1997, as projected by NERC, then an additional 50,000 MW of generation capacity will be required in addition to plants currently under construction. NERC states that some 41,000 MW is planned, but not yet under construction.
- However, a more rapid demand growth rate of 2.9 percent annually for this period, conservative by recent standards, necessitates the additional construction of almost 105,000 MW beyond plants currently under construction, according to A.G.A. calculations. Even taking into account the 41,000 MW that is planned, there would still be a shortfall of 64,000 MW in 1997.
- The Energy Information Administration's (EIA) annual review of the electric utility industry also indicates that capacity requirements in the next decade far exceed current construction levels. The Annual Outlook for U.S. Electric Power 1988 projects that 126,400 MW of new generation capacity additions will be required by the year 2000.
 - Almost 60,000 MW of EIA's total projected additions are expected to consist of natural gas combined-cycle and combustion turbine generators (3,160 Bcf of gas demand). Of this 60,000 MW, NUGs are expected to contribute 17,600 MW of new gas-fueled systems.
- A recent Electric Power Research Institute (EPRI) analysis, titled "Utility Turbopower for the 1990s," predicts as much as 75,000 MW of the next 100,000 MW put in place could potentially be gas turbine-based. The analysis indicates gas-fueled capacity's low capital cost (\$300/kW for simple cycle and \$600/kW for combined cycle) and competitive gas rates makes these units the most economical choice when compared with any other alternative.

Background

From 1965 to 1974, summer peak demand for electricity grew at a 7.2 percent annual rate. To meet this high level of demand, utilities planned and constructed new baseload generation capacity 8 to 10 years before its initial operation date. However, after the oil embargo electricity demand growth

slowed. This resulted from rising electricity rates and a nationwide movement toward conservation. From 1974 to 1981, peak demand growth fell to 3.0 percent a year. This growth continued to slow in the early 1980s, which were characterized by high rates of inflation and interest along with almost stagnant economic growth. In 1982 electricity sales to end-users declined 2.8 percent, the first absolute decline since 1945. More recently, peak demand growth has started to accelerate, increasing to 3.6 and 4.0 percent in 1986 and 1987, respectively. Continued growth of this magnitude will require the construction of new plants to augment current capacity.

Figure 2 shows how generation capacity grew at a faster rate than peak demand from 1973 through 1982. This trend of rapid supply growth and declining demand growth led to an over supply or excess capacity of generation facilities and to a significant reduction in the amount of planned new additions. During the past five years, however, this trend has been reversed. From 1983 to 1987, peak demand increases have overtaken generator unit additions. The impact of this reversal has been a reduction in excess capacity as demand growth continued to outpace new supply additions.

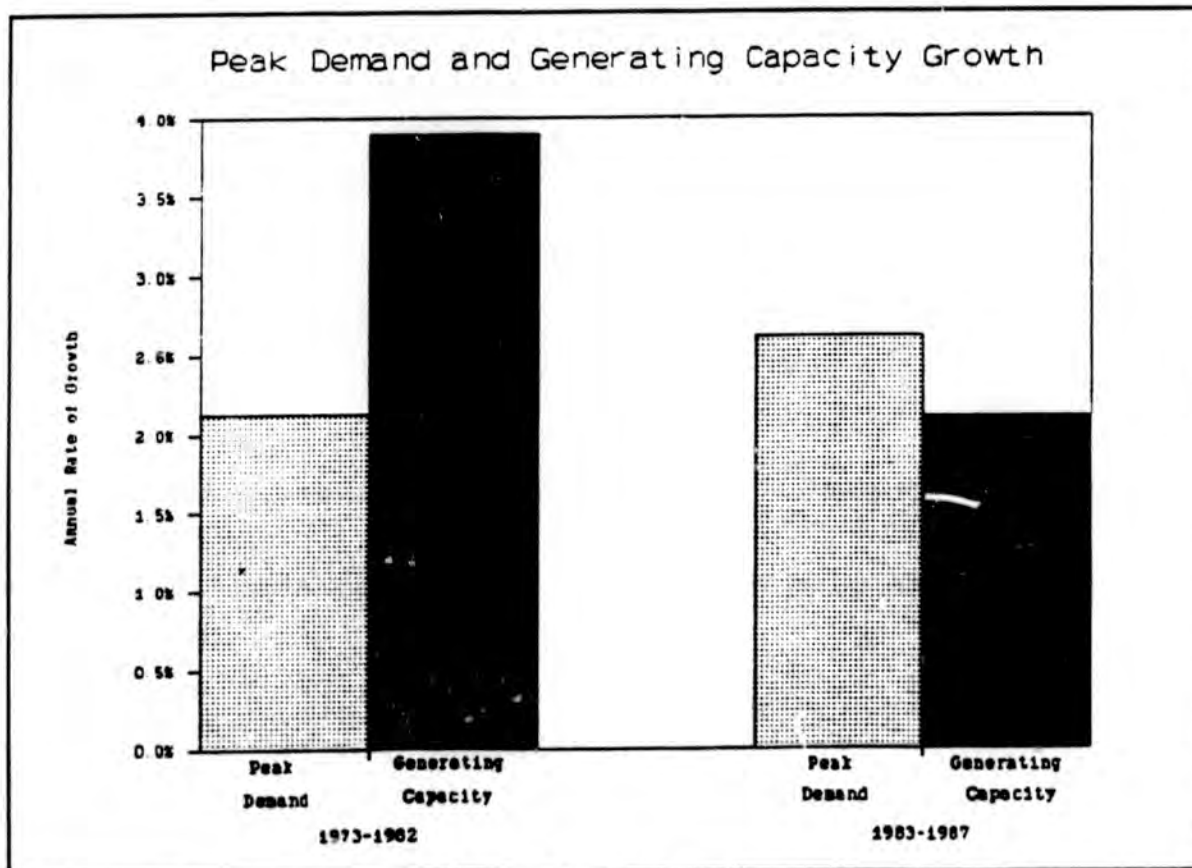


Figure 2

As excess capacity developed, relatively high interest rates further increased the cost of carrying these new additions. State commissions began to conduct prudence investigations as to whether the cost of these surplus plants should be allowed into the utilities' rate base. Plant cost disallowances were estimated to be \$12.7 billion in 1987 alone.¹ The prospect of future disallowances has made utility investment in new, capital intensive generation plants relatively more risky.

In 1984 A.G.A. analyzed nuclear plant construction trends to determine how natural gas demand may be affected.² The study determined that longer than expected lead-times for construction, changes in regulatory licensing, and less than favorable generation economics led to a number of nuclear plant cancellations. It was clear that after the current class of nuclear plants were completed, future nuclear additions were unlikely. Currently, there are 16 nuclear plants under construction and projected to become operational in less than 10 years. Two other units, Seabrook and Shoreham are completed, but not operating due to regulatory and financial problems.

Coal-fired plants were analyzed in a 1985 A.G.A. analysis.³ This study noted that the escalating capital costs required to build new coal capacity that met applicable environmental standards was higher than a number of gas-based alternatives. It also pointed out that the number of new planned coal-fired plants was decreasing, from 100,000 MW of planned capacity in 1980 down to 42,000 MW in 1985 (contrasted with 15,400 MW in 1988).

Most recently, a 1987 A.G.A. analysis determined that an additional 44,300 MW of new generation capacity over current construction levels would be needed by 1995 if peak demand grew 2.2 percent annually.⁴ It was recognized that if demand grew at a rapid 3.3 percent annually, then 98,500 MW would be required. The analysis discussed a number of natural gas-powered generation options that can play a significant role in satisfying these capacity requirements. In particular, 1988 data indicate that gas combined-cycle and combustion turbine systems are expected to make up the largest share of unplanned future additions.

Methodology

A number of industry-wide analyses were considered in evaluating electric generation capacity and electricity demand trends in an effort to determine the extent to which gas-based systems will be needed to satisfy future generation requirements. The two principal studies evaluated in the area of future capacity needs based on utility power pool data were: NERC's 1988 Reliability Assessment; and the Department of Energy's (DOE) Staff Report Electric Power Supply and Demand for the Contiguous United States 1987-1996.^{5,6}

The NERC study questioned the adequacy of future electric generation capacity, especially during the mid-1990s, while the DOE report concluded that several regional power pools, primarily ranging from New England to the Southeast, would develop generation shortages. Both of these studies assume that some 73,400 MW of additional new capacity will become available between now and 1997 even though 40,900 MW of this capacity is not yet under construction. Furthermore, the DOE report indicates that reliability can be maintained only if all of the projected capacity is completed as currently scheduled, and that new construction of additional capacity be available for commercial operation by 1992.

In order to evaluate utilities' installed generation capacity, peak demand loads and future capacity additions, NERC's 1988 Electricity Supply and Demand study was used.⁷ This study defined planned capacity additions as those plants that are planned for construction. However, in most cases these additions are not actually utility authorized for construction. Therefore, in order to more realistically determine the degree to which future electricity demand will be met by additions to the current generation stock, only those capacity additions currently under construction were used.

Given NERC projections of installed generation capacity, each annual figure was adjusted downward to reflect the additional on-line capacity of only those plants currently under construction and scheduled to become operative during the year in question. This procedure was performed for each year, 1989-1997. Given adjusted installed capacity and peak demand (either Base Demand Growth Case or Rapid Demand Growth Case figures), capacity margins were calculated using the following formula:

$$\frac{\text{Adjusted Installed Capacity} - \text{Peak Demand}}{\text{Peak Demand}} \times 100\%$$

All areas with calculated capacity margins 20 percent and larger were deemed to have sufficient capacity. In other words, available capacity exceeds peak demand by 20 percent. However, regions that fall below 20 percent are projected to have capacity shortages. Table 1 shows the results of this analysis by describing the potential shortfall (i.e. the volume of capacity that falls short of the 20 percent capacity margin test) for each electricity sub-region. As a means of assessing the availability of capacity in the face of forced outages, scheduled maintenance or capacity reductions due to emission restrictions, the 20 percent capacity margin approach is generally accepted.

The results of this capacity margin analysis were then compared with the recent EIA study, Annual Outlook for U.S. Electric Power 1988.⁸ This study projects generation requirements given a number of assumptions concerning

retirements, plant efficiencies, capacity factors, etc.

Results

● Historical Perspective

Slowing demand growth was one factor leading to a reduced rate of capacity additions in the 1980s. Large cost overruns associated with ambitious attempts to build power plants that were much larger than previous units, coupled with the financial impact of high interest rates on these large investments, also had a definite dampening effect on utility planners. In response to these developments, utilities continually reduced the number of future planned additions over the past 10 years. In 1988, planned additions were 73,400 MW or 71 percent less than the 250,000 MW planned 10 years earlier in 1979. Similarly, the number of planned coal and nuclear plants has fallen from 125,000 MW and 107,000 MW in 1979 to 15,400 MW and 18,200 MW in 1988, respectively. On the other hand, since NERC began projecting NUG additions, this capacity has tripled from 6,600 MW in 1985 to 19,800 MW in 1988. These additions exceed the projections of new coal and nuclear capacity.

NERC, a federation of nine regional power pools representing investor-owned, federal, rural, cooperative, state, and municipal electric utilities, currently forecasts additions of 73,400 MW of generation capacity by 1997. Of this, only 32,500 MW is actually under construction. The remaining 40,900 MW of capacity is in the planning stage. Table 1 shows that if peak demand grows at the rate of 1.9 percent annually as NERC projects, then an additional 49,751 MW (versus the 40,900 MW) will need to be built beyond the 32,500 MW under construction. In a more rapid growth case where peak demand is assumed to grow at 2.9 percent annually through 1997, 104,826 MW of additional capability would be required. These additions supplement the 32,500 MW currently under construction. Appendix B lists these calculated shortfalls by NERC region and sub-region by year through 1997.

These results are similar to A.G.A.'s findings nearly two years ago, suggesting no recent improvement in future capacity availability. Using data from the NERC report, 1986 Supply and Demand, that study found that a base peak demand growth of 2.2 percent a year from 1986 to 1995 would result in shortages of 43,500 MW. The rapid case scenario of 3.3 percent demand growth showed that an additional 98,500 MW would be needed. This year's report, however, assumed smaller demand increases compared with earlier years, based on NERC's projection of demand growth. This year's report, therefore, suggests that even at slower rates of growth of peak electricity demand, future generation capacity will be inadequate by the mid-1990s. In addition, NERC's 1.9 percent peak demand growth rate can be characterized as overly conservative since the last two years peak demand has grown 3.6 and 4.0 percent, respectively.

**NERC Planned Utility-Owned Generator Unit Additions
100 MW or More - Not Under Construction**

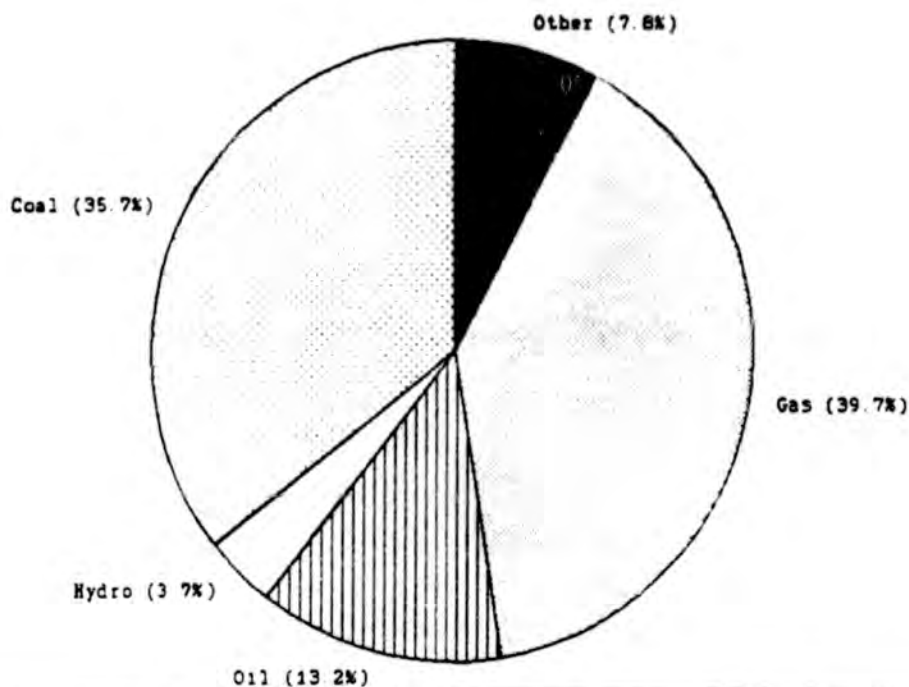


Figure 3

● **Future Outlook**

As electricity consumption growth outstrips the rate of new capacity additions, excess capacity diminishes and a significant amount of new capacity additions will be required to ensure system reliability by the mid-1990s. If peak electricity demand grows 1.9 percent annually between 1989 and 1997, then an additional 49,751 MW of generation capacity will be required in addition to plants currently under construction. However, a more rapid demand growth rate of 2.9 percent for this period, conservative by recent standards, necessitates the additional construction of almost 105,000 MW. In contrast, 40,900 MW are planned beyond current construction levels, according to NERC.

Natural gas-fueled combined-cycle, ISTIG (inter-cooled steam-injected gas turbines), and combustion turbines are expected to make up a major share of this new capability. Given the uncertainty, public resistance and high costs associated with building nuclear power plants, future baseload additions will most likely consist of coal-steam and gas combined-cycle units. Coal-steam plants have generally been the conventional choice for baseload systems. But today, gas-based systems on the average enjoy lower life-cycle costs than coal-steam plants.

In fact, recent advances in combustion turbine technology

Given these probable shortfalls in generation capacity, what measures can be taken to remedy this potential problem? Increased bulk power transfers are often cited as remedies in regions where power is short. However, as Table 1 shows, all areas in the rapid case experience shortages in generation capacity in 1997. Therefore, it is questionable where surplus capacity will originate that will permit power transfers. Another possible solution is for utilities to reduce their capacity margins from 20 percent to 15 percent. Indeed, some utilities have been able to operate reliably in this fashion. But for the nation's combined generation system, this is not practical. Over the past four summer peak demand periods, an average of 15.5 percent of the nation's generation stock has been unavailable because of forced outages, scheduled maintenance, and "other" outages. It is apparent that increased bulk power transfers and reducing capacity margins cannot be substituted for new capacity additions.

Exacerbating the problem of tight generation supplies is the status of nuclear power. Once regarded as cost efficient and pollution free, projected nuclear additions are declining. Not one nuclear plant has been ordered since 1978. There are currently 16 nuclear plants more than 50 percent complete rated at 18,200 MW of capacity. However, it is questionable whether all of these plants will become operable over the next 10 years. Seven of these plants do not have reliable start-up dates. Also there are four Tennessee Valley Authority (TVA) plants under construction whose completion dates are unknown. Construction of these units has been slowed to allow safety investigations at TVA's five completed plants. If these plants are not operating by the mid-1990s, then an even larger amount of new capacity will be required.

Another possible solution would be to build new coal-steam generation plants. NERC projects an additional 15,400 MW of coal capacity will also be available by 1997. But given the 10- to 12-year lead times required for regulatory approval and construction, it is doubtful whether all of this new capacity will become available. Fourteen plants rated at 9,500 MW are currently under construction. The remaining 5,900 MW of coal capacity include utility planned but unauthorized plants, plants waiting to receive regulatory approval and units with regulatory approval, but not yet under construction. It is questionable whether these plants will be available for operation before 1997. However, NERC expects gas-based systems to comprise a major share of future additions. Figure 3 shows these systems are gaining favor with electric utilities. Of the total amount of planned capacity additions 100 MW or larger not currently under construction, natural gas capacity leads all other categories, including coal systems, with almost a 40 percent share.

have resulted in relatively more efficient and reliable gas combustion turbines rated between 135 and 150 MW. These systems are far cleaner burning than coal systems equipped with state-of-the-art pollution control equipment. When these new turbines are combined with a heat-recovery system, efficiencies rise to 45-47 percent. A recent analysis by the EPRI indicated that as long as natural gas costs less than \$6 per million Btu, gas-fueled capacity's low capital cost (\$300/kW for simple cycle, \$600/kW for combined cycle) gives it the lowest projected cost of electricity compared with any alternative now available or expected in the next several years. The analysis also indicated that as much as 75,000 MW of the next 100,000 MW of new capacity put in place could potentially be gas turbine based.¹⁰

The competitive advantages of these gas-based systems has led to a significant amount of this capacity being built by non-utility generators or NUGs. These additions have been induced by implementation of the Public Utility Regulatory Policies Act (PURPA) of 1978. A section of this act provides for cogenerators that meet PURPA's operating standards to sell self-generated electricity to electric utilities. The electricity these industrial producers generate reduce the need for additional utility generation by reducing its demand upon the electric utility and by selling its additional supplies of electricity at the utility's designated avoided cost. A.G.A. estimates that 45 percent of total existing cogeneration capacity, some 17,300 MW, is gas-fueled.¹¹

NERC states that projected NUG generation capacity has grown more than 300 percent since 1985. NUGs are expected to provide almost 27 percent or 20,128 MW of generation capacity to the industry by 1997. A complete break-out of NUG capacity by fuel type is not available. This is because many utilities are not reporting fuel requirements for their cogenerators. Table 2 breaks down projected NUG additions by fuel type. Gas is clearly the dominant generation fuel. More than 47 percent of all fuel-designated capacity is gas driven. It is estimated that more than half of the capacity labeled "other or unknown" will also be gas driven. This estimate is corroborated by EIA, which projects that 60 percent of future NUG additions will be gas-fueled.¹²

How long utilities can refrain from constructing large amounts of new capacity additions will depend on the rate of future demand growth. In 1986 and 1987, peak demand increases were 3.6 and 4.0 percent, respectively. Growth in 1987 was twice the rate projected by NERC's 1987-1996 forecast. The summer heat wave in 1988 pushed demand to record levels for a number of utilities. Another explanation for this accelerated growth in demand is that real electricity prices are falling. Least-cost planning, relatively low capital expenditures, and relatively lower fuel input prices have resulted in lower rates. In 1987, average real electric rates dropped 5.7 percent. It should be noted that average real gas prices for electric generation dropped 10.5 percent.

Table 2

NERC Projected Non-Utility Generator Additions
by Fuel Type 1988-1997

<u>Fuel Type</u>	<u>MW</u>	<u>% of Total</u>
Natural Gas	3,029	15.0
Hydro	500	2.5
Coal	1,315	6.5
Geothermal	594	3.0
Wind	84	0.4
Solar	100	0.5
Refuse (Solid Waste)	458	2.3
Wood/Wood Wastes ¹	346	1.7
Other or Unknown	13,702	68.1

¹Believed to be mostly gas-based capacity.

The belief that large amounts of new generation capacity are needed is also embodied in the Energy Information Administration's (EIA) Annual Outlook for U.S. Electric Power 1988. Given assumptions concerning capacity factors, plant efficiencies, retirements, refurbishment, capital costs, and fuel costs, the study projects that 126,400 MW of new capacity, will be required by the year 2000. Almost 60,000 MW of this capacity would be fueled by natural gas.

The analysis classifies new additions into planned, unplanned, and non-utility categories. Planned additions are generally analogous to NERC's "additions under construction" classification. All of this capacity, some 44,200 MW, is projected to become operable. Only 3,500 MW is gas-driven. In contrast, the study sees an additional 52,800 MW of unplanned utility additions becoming available by 2000. About 72 percent of these additions or 38,400 MW is expected to be either gas combined-cycle or combustion turbines. Additions by NUGs are projected to add another 29,400 MW to the system. About 60 percent of all NUG additions are expected to be fueled with natural gas.

Conclusion

Over the past decade the electric utility industry has continually reduced its plans to build new generation capacity. The two major types of generation supply--nuclear and coal systems--have followed this trend. In fact, natural gas holds the largest share of planned additions 100 MW or larger, but not yet under construction. On the other hand, non-utility generation sources are expected to increase significantly. Both NERC and EIA data suggest that natural gas will account for a

majority of new NUG additions. Because of the competitiveness of natural gas systems, combustion turbine, ISTIG, and combined-cycle units are expected to account for 60 percent of future NUG additions. As generation supply continues to tighten in the mid-1990s, these gas-driven systems will provide the most cost-effective, the most fuel-efficient and the most time-effective means of meeting rising electricity demand levels.

FOOTNOTES

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2. American Gas Association, "Impact of Nuclear Plants' Anticipated Costs on Future Electric Prices," Energy Analysis 1984-14, (Arlington, VA: A.G.A., November 9, 1984).
3. American Gas Association, "Analysis of New Coal-Fired Electric Generation Capacity," Energy Analysis 1985-11, (Arlington, VA: A.G.A., July 3, 1985).
4. American Gas Association, "Gas Options to Offset Anticipated Electric Generation Shortages in the mid-1990s," Energy Analysis 1987-3, (Arlington, VA: A.G.A., May 21, 1987).
5. North American Electric Reliability Council, 1988 Reliability Assessment, (Princeton, NJ: NERC, September 1988).
6. U.S. Department of Energy, Staff Report Electric Supply and Demand for the Contiguous United States 1987-1996, DOE/IE-0008, (Washington, DC: National Technical Information Service, February 1988).
7. North American Electric Reliability Council, 1988 Electricity Supply and Demand, (Princeton, NJ: NERC, October 1988).
8. Energy Information Administration, Annual Outlook for U.S. Electric Power 1988.
9. U.S. Department of Energy, Staff Report Electricity Supply and Demand for the Contiguous United States 1987-1996.
10. Electric Power Research Institute, "Utility Turbopower for the 1990s," EPRI Journal, April/May 1988.
11. American Gas Association, "Estimated Current Natural Gas Cogeneration Capacity: 1988 Update," Planning and Analysis Issues 1988-4, (Arlington, VA: A.G.A., March 18, 1988).
12. Energy Information Administration, Annual Outlook for U.S. Electric Power 1988.

Appendix A

North American Electric Reliability Council Listing of Regions and Subregions

Regions

ECAR
East Central Area Reliability
Coordination Agreement

ERCOT
Electric Reliability Council
of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-American Interpool Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating
Council

SERC
Southeastern Electric Reliability
Council

SPP
Southwest Power Pool

Subregions

None-Michigan, Indiana,
Ohio, Kentucky, West
Virginia

None-Texas

None-New Jersey,
Pennsylvania, Maryland,
Delaware

CE-CMNWLTH EDISON-
Commonwealth Edison
Company Subregion
(North Illinois)
EM-EAST MISSOURI-East
Missouri Subregion
SCI-S. CENT. ILLINOIS-
South Central Illinois
Group
WUM-WIS-UPPER MICH.-
Wisconsin-Upper
Michigan Subregion

None-N. Dakota, S. Dakota,
Nebraska, Minnesota,
Iowa

NY-New York-New York Power
Pool
NE-NEW ENGLAND-New England
Power Pool

FL-FLORIDA-Florida
Subregion
SOU-SOUTHERN-Southern
Subregion
TVA-Tennessee Valley
Authority Subregion
VAC-VACAR-Virginia
Carolinas Subregion

SE-SOUTHEAST-Western
Mississippi,

WSCC
Western System Coordinating
Council

Southeastern Texas,
Eastern Arkansas,
Southeastern Missouri
and Louisiana
WC-WEST CENTRAL-Western
Arkansas, the Texas
Panhandle, Northeast
Texas, and Oklahoma
N-NORTHERN-Western
Missouri and Kansas

NWP-NW POOL-Northwest
Power Pool Area
RMP-ROCKY MT. AREA-Rocky
Mountain Power Area
AZN-ARIZ-N.MEX.-Arizona-
New Mexico Power Area
CNV-CALIF-SO.NEV.-
California-Southern
Nevada Power Area

Appendix B

Appendix B contains two tables: one showing projected electric generation shortages by year through 1997, and the other showing the comparison of expected capacity growth rates for plants under construction only to a range of peak electricity demand growth rates. Only those areas with shortages are represented.

The table "Electric Generating Shortages" shows the megawatt additions required to satisfy a 20 percent capacity margin. Zero values indicate capacity margins about 20 percent, i.e. surplus capacity.

Note that a region's calculated Base Demand Growth Case shortage depends on its base peak demand growth rate. Similarly, the Rapid Demand Growth Case shortages are dependent on the rapid peak demand growth rate. The column labeled "86 EA Reported Numbers" refers to the rapid growth case scenario of an earlier analysis using 1986 data. These rates are shown in the adjoining table.

Note: The nine pages of backup tables are not included in this copy.