UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

OFFICE OF FOSSIL ENERGY

Phillips Alaska Natural Gas Corporation and Marathon Oil Company	)	**FE Docket No. 96-99-LNG**

ORDER EXTENDING AUTHORIZATION
TO EXPORT
LIQUEFIED NATURAL GAS
FROM ALASKA

DOE/FE Opinion and Order No. 1473

APRIL 2, 1999

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GLOSSARY OF ABBREVIATIONS

ADNR	Alaska Department of Natural Resources
AOGCC	Alaska Oil and Gas Conservation Commission
Applicants	Phillips Alaska Natural Gas Corporation and Marathon Oil Company
Aurora	Aurora Power Resources, Inc.
Bcf	Billion cubic feet
Btu	British Thermal Unit
DOE	Department of Energy
DO&G	Division of Oil and Gas, Alaska Department of Natural Resources
DOR	Department of Revenue, State of Alaska
EA	Environmental Assessment
Eason	James E. Eason, contractor to ENSTAR
EIA	Energy Information Administration, DOE
EIS	Environmental Impact Statement
ENSTAR	ENSTAR Natural Gas Company
ERA	Economic Regulatory Administration, DOE
FE	Office of Fossil Energy, DOE
FPC	Federal Power Commission
GeoQuest	Schlumberger GeoQuest Reservoir Technologies, contractor to the Applicants
ISER	Institute of Social and Economic Research, University of Alaska
LNG	Liquefied natural gas
Marathon	Marathon Oil Company
MHA	Malkewicz Hunei Associates, contractor to ENSTAR
MMS	Minerals Management Service, Department of the Interior
NEPA	National Environmental Policy Act
NGA	Natural Gas Act of 1938
PANGC	Phillips Alaska Natural Gas Corporation
PGC	Potential Gas Committee
Resource Decisions	Resource Decisions and Northern Economics, contractor to the Applicants
SPE	Society of Petroleum Engineers
Sproule	Sproule Associates Inc., contractor to the Applicants
Tcf	Trillion cubic feet
Unocal	Union Oil Company of California
USGS	United States Geological Survey, Department of the Interior
WPC	World Petroleum Congress
Zobrist	Daniel H. Zobrist, petroleum economist for ADNR

I. SUMMARY

The Office of Fossil Energy (FE) of the Department of Energy (DOE) is granting the application of Phillips Alaska Natural Gas Corporation and Marathon Oil Company (hereinafter PANGC and Marathon or Applicants) for a five-year extension of their authorization to export liquefied natural gas (LNG) from the State of Alaska to Japan. In so doing, the Department has determined this export extension will not be inconsistent with the public interest.

II. PROCEDURAL HISTORY

A. Background

The history of this export, authorized originally in 1967 by the Federal Power Commission (FPC),[1/] has been remarkably uneventful when compared to the drama that has characterized exploration and development activities in Alaska and natural gas regulation generally.[2/] The FPC authorized Phillips Petroleum Company, a predecessor of PANGC, and Marathon to export LNG to Tokyo Electric Power Company Inc. (Tokyo Electric) and Tokyo Gas Company Limited (Tokyo Gas) during a 15-year period beginning in March 1969, after construction of the necessary liquefaction and marine terminal facilities in the Cook Inlet Basin. Between 1967 and the filing of the application in this proceeding, the export authority was amended seven times, by the former Economic Regulatory Administration of DOE, a predecessor of FE, in 1982, 1986,

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1/ *See* 37 F.P.C. ¶ 777 (1967). The FPC's regulatory authority over imports and exports of natural gas was transferred to the Secretary of Energy in 1977 by the Department of Energy Organization Act, 42 U.S.C. §§ 7151, 7172; the Secretary, in turn, delegated the authority to the Administrator of the Economic Regulatory Administration (ERA), Delegation Order No. 0204-111 (49 Fed. Reg. 6684, February 22, 1984), and then to the Assistant Secretary of Fossil Energy, Delegation Order No. 0204-127 (54 Fed. Reg. 11436, March 10, 1989).

2/ For extensive background information, see *Yukon Pacific Corporation*, DOE Opinion and Order No. 350, 1 FE ¶ 70,259 (1989), *denied on reh'g*, 1 FE ¶ 70,303 (1990). Order 350, as modified on rehearing, authorized Yukon Pacific to export for sale to Pacific Rim nations a total of up to 350 million metric tons (MMT) of LNG, at an average annual volume of 14 MMT, over a 25-year term beginning on the date of first delivery. The export project encompasses the proposed Trans-Alaska Gas System (TAGS) and related facilities, including production and gas conditioning facilities, liquefaction plant, marine terminal, and LNG tankers.

1987, and 1988, and by FE in 1991, 1992, and most recently in 1995.[3/] None of these proceedings was contested.

PANGC and Marathon have maintained throughout this period an uninterrupted export relationship with Japan. They currently are authorized to export up to 64.4 trillion Btu's (approximately 64.4 billion cubic feet (Bcf)) of LNG per year, nearly 35 percent of the 1997 market for Cook Inlet natural gas, over a 15-year period ending March 31, 2004.

B. Application and Project Description

On December 31, 1996, the Applicants filed an application requesting that the Department extend their authorization to export LNG from Alaska to Japan for five years, from April 1, 2004, through March 31, 2009.[4/] Under the requested extension, the natural gas would continue to be produced from gas fields owned or controlled by the Applicants in the Cook Inlet area of Alaska,[5/]

3/ *See* DOE/ERA Opinion and Order No. 49 (1 ERA ¶ 70,116, December 14, 1982); DOE/ERA Opinion and Order 49-A (1 ERA ¶ 70,127, April 3, 1986) (transferred authorization from Phillips Petroleum Company to Phillips 66 Natural Gas Company); DOE/ERA Opinion and Order No. 206 (1 ERA ¶ 70,128, November 16, 1987); DOE/ERA Opinion and Order No. 261 (1 ERA ¶ 70,130, July 28, 1988); DOE/FE Opinion and Order No. 261-A (1 FE ¶ 70,454, June 18, 1991); DOE/FE Opinion and Order No. 261-B (1 FE ¶ 70,506, December 19, 1991) (transferred authorization from Phillips 66 Natural Gas Company to PANGC); DOE/FE Opinion and Order 261-C (1 FE ¶ 70,607, July 15, 1992) (increased annual export authority to Japan from 52 trillion Btu's to 64.4 trillion Btu's - the provision for annual sales of up to 106 percent of annual contract quantity remained unchanged); and DOE/FE Opinion and Order No. 261-D (1 FE ¶ 71,087, March 2, 1995) (collectively referred to as Order 261).

4/ PANGC, a Delaware corporation with its principal place of business in Bartlesville, Oklahoma, is a wholly owned subsidiary of Phillips Petroleum Company. Marathon, an Ohio corporation with its principal place of business in Houston, Texas, is a wholly owned subsidiary of USX Corporation. PANGC and Marathon are not affiliated with each other.

5/ The Applicants have been significant operators in the Cook Inlet area for decades. They operate three of the basin's six largest fields and control approximately 48 percent of the basin's reserves.

manufactured into LNG at the Applicants' existing liquefaction plant near Kenai, Alaska,[6/] and transported by tanker to Japan for sale to Tokyo Electric and Tokyo Gas, the two largest electric and gas utilities in Japan. The proposed extension would involve no new construction or other operational changes.

The pricing and other provisions in the Applicants' current LNG sales contracts with Tokyo Electric and Tokyo Gas would remain the same during the extension period. As currently authorized, these contracts contain a market-sensitive pricing formula under which the monthly selling price per million Btu's of LNG exported to Japan is adjusted each month to reflect changes over a three-month period in the selling price of all crude oils imported into Japan.[7/]

In response to a request from the Applicants, their Japanese purchasers signed a Letter Agreement on May 17, 1993,[8/] to extend the utilities' purchase commitment(s) for five years, from April 1, 2004, to and including March 31, 2009, subject to the Applicants' written acceptance on or before March 31, 2001.[9/] Pursuant to the Agreement, the Applicants began reporting to their Japanese purchasers the status of extension activities, including their export application, on April 1, 1998.

6/ The Kenai LNG plant is owned by Kenai LNG Corporation, 70 percent of which is owned by PANGC and 30 percent by Marathon. It is the largest LNG manufacturing, and only LNG export, facility in North America.

7/ These crude oil selling prices are reported in *Japan Exports & Imports Monthly*, which is edited by the Customs Bureau, Ministry of Finance, and published by the Japan Tariff Association.

8/ Included as Appendix A to the Application.

9/ S*ee Answer of Phillips Alaska Natural Gas Corporation and Marathon Oil Company in Opposition to Protests, Motions to Dismiss or Defer, Requests for Additional Procedures, and Motion for Consolidation of ENSTAR Natural Gas Company, Union Oil Company of California, Northern Eclipse LLC and Fairbanks Natural Gas LLC, and Aurora Gas, Inc.*, filed May 9, 1997, at 3.

C. Notice and Interventions

DOE issued a notice of the application on February 25, 1997, inviting protests, motions to intervene, notices of intervention, and comments to be filed by April 3, 1997.[10/] Motions to intervene were filed by ENSTAR Natural Gas Company (ENSTAR), Union Oil Company of California (Unocal),[11/] Northern Eclipse LLC and Fairbanks Natural Gas LLC jointly,[12/] and Aurora Gas, Inc. (Aurora),[13/] all opposing the application and requesting, in addition to intervention, various other procedures if DOE did not dismiss the application.

DOE has also received letters from 42 interested persons who did not seek to intervene, including the City of Kenai, the Municipality of Anchorage, 17 State of Alaska legislators, and U.S. Senators Ted Stevens and Frank Murkowski.

D. Order Requesting Additional Information

On November 6, 1997, the Department issued a procedural order requesting additional information and written comments from the Applicants and intervenors.[14/] DOE denied motions requesting: (1) dismissal of the application as premature; (2) a public conference; (3) a trial-type hearing; and (4) an opportunity to conduct formal discovery.[15/] The requests for additional

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10/ 62 Fed. Reg. 9758 (March 4, 1997).

11/ Unocal simultaneously filed a complaint regarding the Applicants' current export authorization as part of its intervention in this docket and in ERA Docket No. 88-22-LNG. DOE dismissed the complaint on July 18, 1997, 1 FE ¶ 71, 429 (DOE/FE Opinion and Order No. 261-E). Unocal did not request rehearing of Order 261-E.

12/ On June 30, 1997, Northern Eclipse and Fairbanks withdrew their intervention and protest "with prejudice."

13/ Now known as Aurora Power Resources, Inc.

14/ *See Order Requesting Information and Written Comments*.

15/ *Id*. On November 20, 1997, ENSTAR filed a motion with DOE for an order compelling the production of data and other documents from PANGC and Marathon. The Applicants filed a joint answer on December 5, 1997, opposing

(continued...)

procedures were denied without prejudice to the filing of similar requests at a later stage in the proceeding.[16/] The procedural order requested submission of initial comments by December 22, 1997, reply comments by February 5, 1998, and any requests for additional procedures by February 20, 1998.

DOE received initial and reply comments from all parties and the Protestors' filings on February 20 requested additional, although by Unocal largely unspecified, procedures in the event DOE did not deny the application. Aurora and ENSTAR requested an opportunity, respectively, to respond to the Applicants' last filed comments and to close the evidentiary phase of this proceeding. Aurora renewed its request for both a trial-type and a public hearing in Anchorage, Alaska. ENSTAR again requested from the Applicants certain information not supplied during informal discovery.[17/] Finally, ENSTAR and Unocal renewed their requests for procedures which they argued are required by DOE regulations implementing the National Environmental Policy Act of 1969 (NEPA).[18/]

E. Order Permitting Clarification of Exhibit on Deliverability

Following submission of the motions and comments on February 20, 1998, the Applicants filed a response on March 9, 1998, asserting DOE should deny the motions for additional procedures and proceed with a final decision on the export extension. In addition, the Applicants

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(...continued)
ENSTAR's motion. On December 16, 1997, DOE issued an order denying ENSTAR's motion, "without prejudice to the consideration of such a request in accordance with the schedule set forth in Paragraph C of the [November 6] procedural order." ENSTAR and the Applicants did agree to an informal discovery arrangement among themselves.

16/ *See* DOE's November 6, 1997, Procedural Order at 12-13.

17/ Information exchanged during informal discovery by the Applicants and ENSTAR has been placed in the official docket file.

18/ 42 U.S.C. § 4321, *et seq.*

asserted DOE should not accept what they characterized as unsolicited comments included by Unocal and ENSTAR in their motions for additional procedures. If these comments were added to the record, the Applicants requested an opportunity to respond. The Applicants also stated they intended to file a clarification of Exhibit L to their December 22, 1997, comments. ENSTAR and Unocal answered the Applicants' March 9 response.

On March 26, 1998, DOE issued a procedural order granting the Applicants' request to file the proposed clarification of Exhibit L, and permitting the Protestors to file reply comments limited to the Applicants' clarification and supporting data. By way of clarification, the Applicants provided two forecasts on April 15, 1998; the forecasts plot the projected deliverability of Cook Inlet production from 1998 through 2013.[19/] ENSTAR, Unocal, and Aurora all filed replies.[20/]

19/ *See* Sproule Associates Inc.(Sproule), *Clarifications to PANGC and Marathon's Deliverability Forecast, Cook Inlet, Alaska* (April 8, 1998), filed by the Applicants on April 15, 1998.

20/ On January 25, 1999, Richard F. Barnes, President of ENSTAR, sent a letter to Robert S. Kripowicz as Acting Assistant Secretary for Fossil Energy, enclosing an internal Marathon memorandum, dated May 19, 1994, from F.R. Adamchak to R.G. Grammens. The letter pointed out what Mr. Barnes characterized as inconsistencies between assertions regarding gas supply made by Marathon in this export proceeding and those reflected in the memorandum, and reemphasized the need for the Department to grant ENSTAR's request for further procedures. On January 26, 1999, the Department returned ENSTAR's letter and enclosure determining the information, submitted in further support of arguments made by ENSTAR throughout the proceeding, was not necessary for resolution of the issues in the case and would not be made part of the record.

On March 2, 1999, Unocal filed a motion for leave to submit an attached update to its comments. Contrary to Unocal's belief, the Department decided the agency would not "'benefit from a freshening' of matters fully briefed" in an already extensive record. The Department denied the motion in an order issued March 4, 1999, and returned the filing to Unocal.

III. COMMENTS

A. The Protestors

The positions of the three Protestors have been fundamentally the same throughout this proceeding. Based in large part on supply and demand studies submitted with their comments, they argue DOE approval of the application would cause a shortage of natural gas in southcentral Alaska during the five-year extension period and therefore would be inconsistent with the public interest.

1. ENSTAR

ENSTAR, a local distribution company regulated by the State of Alaska, provides natural gas service to southcentral Alaska. Marathon is one of ENSTAR's four gas suppliers and currently is obligated to supply all of the distributor's requirements exceeding its other firm purchase requirements.[21/] This requirements-type obligation extends through 2001, after which Marathon's obligation is limited for the duration of the supply contract (approximately 2015) to an annual quantity fixed in the contract.[22/]

In order to assess the impact of the proposed export extension, ENSTAR commissioned three studies: first, an analysis of Cook Inlet gas reserves and deliverability;[23/] second, an

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21/ The Applicants' May 9, 1997, Answer at 14. The Applicants noted PANGC had received no response to its attempts to negotiate a contract with ENSTAR, *infra* at 15.

22/ *Id.* note 13, at 14.

23/ Malkewicz Hueni Associates (MHA), *Analysis of Cook Inlet Alaska Gas Reserves and Deliverability* (December 19, 1997), included as Attachment C to *Comments of ENSTAR Natural Gas Company*, filed December 22, 1997.

assessment of reserve additions;[24] and third, an analysis of natural gas demand through 2009 and the effects of a possible shortage on energy costs and employment in southcentral Alaska.[25]

ENSTAR claims the resource base is not as large as the Applicants estimate and that its supply estimates show a declining reserve base, which, even with reserve additions, would not support anticipated demand within the export extension period. ENSTAR asserts the resulting regional natural gas shortages cannot be averted by investment in storage facilities, and would cause widespread fuel switching to alternate fuels and detrimentally affect both the economy and the environment of southcentral Alaska. Such shortages would be relatively insensitive to supply and demand assumptions, ENSTAR contends, and "[t]he only factor that, by itself, determines whether shortages will result is whether DOE approves the export."[26]

2. Unocal

Unocal is both a producer and user of Cook Inlet natural gas.[27] It has owned and operated a chemical plant in Nikiski, Alaska, on the Kenai Peninsula of Cook Inlet since 1969.[28] Unocal's gas production is dedicated as feedstock to produce ammonia and urea fertilizer

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24/ James E. Eason (Eason), Oil and Gas Operations, Management and Policy, *An Assessment of Potential Gas Reserves Additions from Currently Undiscovered Resources--Cook Inlet, Alaska* (December 22, 1997), included as Attachment B to ENSTAR's December 22, 1997, Comments.

25/ Scott Goldsmith, Institute of Social and Economic Research (ISER), *Two Memoranda on Cook Inlet Gas: Cook Inlet Gas Consumption Projection & The Financial Cost of Premature Loss of Gas to the Railbelt Utilities* (December 18, 1997), included as Attachment D to ENSTAR'S December 22, 1997, Comments.

26/ ENSTAR's December 22, 1997, Comments at 3.

27/ *Motion to Intervene, Motion to Dismiss or Defer, Protest, and Request for Additional Procedures of Unocal Oil Company of California*, filed April 3, 1997, at 4.

28/ *Id.*

products, none sold in Alaska and the majority marketed outside the United States. Unocal has no sales obligations to the local Alaskan market.[29/]

Unocal submitted a gas deliverability study in support of its argument the LNG export will cause, or at least hasten, regional supply shortfalls within the extension period, including curtailments to Unocal's Alaska chemical plant.[30/] These shortfalls, Unocal argues, are ignored by the Applicants' estimates of reserves and demand. Unocal contends the deliverability shortages "preclude a finding that the proposed export is in the public interest"[31/] because they will induce price increases in the local market, stymie growth and reduce tax revenues, and result in loss of jobs, industry shutdowns, fuel switching, and related adverse impacts on the environment and trade. Unocal asserts these losses would outweigh any losses from a denial of the LNG export extension.

3. Aurora

Aurora is an independent aggregator and marketer of natural gas in direct competition with a Marathon marketing subsidiary.[32/] It purchases natural gas from producers in the Cook Inlet region and resells that gas to customers in the Anchorage area. Like Unocal, Aurora protests both the extension application and the Applicants' current export authority under Order

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29/ *E.g.*, the Applicants' February 5, 1998, Reply Comments at 74. Unocal's gas use could be characterized as an "indirect export" because the gas is used to produce a commodity primarily destined for, in this instance the same, export market. *See* DeAnne Julius and Afsaneh Mashayekhi, *The Economics of Natural Gas: Pricing, Planning, and Policy*, Oxford University Press, 1990, at 70.

30/ *Cook Inlet Natural Gas Deliverability Analysis* (December 1997), included as Exhibit A to *Initial Comments of Union Oil Company of California* (Unocal), filed December 22, 1997. Unocal's deliverability report was supported by two companion analyses, also prepared by Unocal and included as Appendices 1 and 2, respectively, to Exhibit A: (1) *Cook Inlet Natural Gas Reserves and Resources*; and (2) *Production Capacity of Cook Inlet Gas Fields.*

31/ Unocal's December 22, 1997, Initial Comments at 8.

32/ The Applicants' May 9, 1997, Answer at 15.

261, claiming deliverable Cook Inlet gas reserves will be needed to meet regional demand and the continuing export of LNG will result in a premature shortage for Alaskans.[33] Aurora contends that while gas storage facilities, if they existed, might reduce perceived deliverability problems, storage is an expensive option that does not increase the availability of gas. In addition, Aurora echoes the claims of ENSTAR and Unocal there are no economically and environmentally acceptable energy supply alternatives to meet demand. Aurora did not undertake an independent study of either supply or demand.[34]

B. The Applicants

In support of their application, the Applicants state there is no regional need for the gas they propose to export.[35] For this assertion, the Applicants rely on analyses which they believe demonstrate there are adequate regional supplies to satisfy both anticipated local demand and the continued export of LNG during the five-year extension.[36] In response to the Protestors' criticisms, the Applicants assert their studies are complete and technically accurate and it is the studies relied on by the Protestors, and their use, which are flawed.[37]

With regard to the Protestors' arguments about deliverability, the Applicants assert projected annual Cook Inlet production will be adequate to meet both annual average local

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33/ *See supra* note 11.

34/ *See Aurora Power Resources, Inc.'s Comments to November 6, 1997, Order Requesting Additional Comments*, filed December 22, 1997, at 5.

35/ National need is not an issue in this proceeding. *See* note 48.

36/ Resource Decisions and Northern Economics (Resource Decisions), *Economic Analysis of Regional and Local Interests Relating to Kenai LNG Export to Japan* (December 11, 1996), and Schlumberger GeoQuest Reservoir Technologies (GeoQuest), *Proven Reserve Assessment Cook Inlet, Alaska Effective January 1, 1996* (March 1996), included as Appendices C and D, respectively, to the Application.

37/ *See, e.g.*, the Applicants' February 5, 1998, Reply Comments, Parts II and III.

demand and the LNG export market.[38] They contend deliverability should not be a consideration in this proceeding but is an issue limited to the peak requirements of the local market. The Applicants claim these requirements are the responsibility of the local gas distribution utility, which currently does not provide peak shaving or gas storage facilities.[39]

The Applicants assert the Department's extension of their export authority would be consistent with agency policy to permit the market to operate without unnecessary regulatory constraints. Not only would DOE's extension not cause Cook Inlet supply shortfalls, the Applicants contend, but if the Kenai LNG exports were discontinued or curtailed, the local market could not absorb the quantity of gas now being exported. And because an extension of their export would not cause local gas shortages, the Applicants assert an extension would not result in significant fuel switching, adverse economic or environmental impacts, or other negative consequences for consumers.[40] On the contrary, the Applicants emphasize the requested export authority would extend current benefits to Alaska's economy, maintain and strengthen the

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38/ *See, e.g.,* Sproule, *Supplemental Report, Proven Reserves Assessment, Cook Inlet* (February 3, 1998), included as Exhibit B to the Applicants' February 5, 1998, Reply Comments.

39/ *See, e.g., Initial Comments of Phillips Alaska Natural Gas Corporation and Marathon Oil Company in Response to November 6, 1997 Order,* filed December 22, 1997, at 11-15; and Foster Associates, Inc., *Peak Shaving and Use of Storage in the U.S. Natural Gas Industry* (December 1997), included as Exhibit A to these Initial Comments. *See also* the Applicants' May 9, 1997, Answer at 111. They assert ENSTAR has been unresponsive to their request for a written expression of interest in using the Kenai LNG Project for a possible peaking gas supply arrangement.

40/ *See generally* the Applicants' May 9, 1997, Answer, Part IV.

long-established international relationship with Japan, and continue reductions to the U.S. trade deficit.[41/]

Finally, the Applicants argue the additional procedures requested by the Protestors are unnecessary and, by requesting them, the Protestors are misusing DOE's regulations to delay approval of the requested export extension.

C. Alaskan Interests

The State of Alaska did not intervene or otherwise comment in this proceeding. However, as noted above, the Department has received letters from both of the U.S. Senators from Alaska, State legislators, local officials, businesses located in the State, and private individuals. None sought to intervene and the great majority supported the application, emphasizing in their comments the long history of safe and reliable operations by the Applicants and the importance of the export project to the State's economy. For the most part, the few comments which expressed concern about the proposed export extension did not oppose it but requested that DOE conduct hearings in Alaska and perform an independent analysis of Cook Inlet gas reserves to determine the adequacy of supply before approving the application.

IV. DECISION

The Applicants filed their application for authorization to extend their export of Cook Inlet, Alaska natural gas under section 3 of the Natural Gas Act (NGA). Section 3 provides, in relevant part:

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy] authorizing it to

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41/ *Id.*

> do so. *The [Secretary] shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest.* The [Secretary] may by [the Secretary's] order grant such application, in whole or part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate.... 15 U.S.C. § 717b (Emphasis added).

Section 3 creates a statutory presumption in favor of approval of an export application, and the Department must grant the requested export extension unless it determines the presumption is overcome by evidence in the record of the proceeding that the proposed export will not be consistent with the public interest.[42/] Opponents of an application bear the burden of overcoming this presumption.[43/] Although the Department considers each application *de novo*, the burden is heavy here in view of the particular circumstances of this long, and until now uncontested, export.

In addition, the plenary authority conferred on the Department by section 3 provides the administrative flexibility necessary to protect sometimes conflicting public interests.[44/] We are guided in making this public interest determination by DOE Delegation Order No. 0204-111.[45/]

42/ In *Panhandle Producers and Royalty Owners Association v. ERA*, 822 F. 2d 1105, 1111 (D.C. Cir. 1987), the court found section 3 of the NGA "requires an affirmative showing of inconsistency with the public interest to deny an application" and that a "presumption favoring...authorization...is completely consistent with, if not mandated by, the statutory directive." *See also Independent Petroleum Association v. ERA*, 870 F. 2d 168, 172 (5th Cir. 1989); *Panhandle Producers and Royalty Owners Association v. ERA*, 847 F. 2d 1168, 1176 ((5th Cir. 1988).

43/ *Id.*

44/ *See Distrigas Corporation v. FPC*, 495 F. 2d 1057, 1064 (D.C. Cir. 1974), *cert. denied*, 419 U.S. 834 (1974). The court made clear the power under section 3 of the NGA extends equally to imports and exports. 495 F. 2d at 1063; *see also Border Pipe Line Company v. FPC*, 171 F. 2d 149 (1948).

45/ In granting the Assistant Secretary of FE the NGA authority over natural gas imports and exports, the Secretary directed the Assistant Secretary to exercise this authority in accordance with the policies and practices that the ERA followed in regulating natural gas imports and exports under Delegation Order No. 0204-111. Thus, while the Assistant Secretary is granted the NGA authority entirely by Delegation Order 0204-127, the exercise of this authority takes into account the same factors prescribed by the Secretary for consideration by ERA under Delegation Order No. 0204-

(continued...)

This Order designates domestic need for the natural gas proposed to be exported as the only explicit criterion that must be considered in determining the public interest. In addition to domestic need, DOE considers other factors to the extent they are shown to be relevant to the public interest determination. Furthermore, in evaluating exports, DOE is mindful of the broad energy policy principles set forth in the Secretary's natural gas import policy guidelines.[46/] The guidelines established a policy of minimizing Federal control and involvement in the natural gas market based on the premise the market, not government, should determine energy contract terms. While those guidelines deal specifically with imports, the principles are applicable to exports as well.[47/]

Finally, the extensive record in this proceeding is comprised of the initial filings and those made in response to the additional procedures extended by DOE, the analyses included with the filings, the largely governmental studies to and upon which these filings and analyses refer and rely, and other published studies. We have reviewed this record thoroughly and our decision in this Order is based upon it.

A. Regional Need

1. Supply

a. Introduction

(...continued)
111(49 Fed. Reg. 6690, February 22, 1984).

46/ *See* 49 Fed. Reg. 6684, February 22, 1984.

47/ *See Yukon Pacific, supra* note 2, 1 FE ¶ 70,259 at 71,128.

In order to determine whether there is a regional need for the natural gas proposed to be exported, the available supply of gas is a paramount issue, and has been addressed by the parties to this proceeding.[48] The Applicants maintain there are sufficient supplies of natural gas for both domestic and foreign markets during the requested export extension period. The Protestors argue granting the extension of the LNG export project for an additional five years will lead to supply shortfalls in the local market. In evaluating the issue of supply, DOE focused on conventional natural gas supplies found in the Cook Inlet area. However, the Order also briefly discusses the enormous potential for additional (Alaska North Slope and unconventional) gas supplies.

As noted above, the Department has carefully reviewed the Cook Inlet natural gas supply forecasts submitted, cited, or relied upon by the parties to this proceeding, as well as various other published supply studies referenced in the Order and made part of the record. The natural gas resource estimates submitted by the Applicants and Protestors used or referred to other estimates prepared by the Colorado School of Mines Potential Gas Committee (PGC), the United States Geological Survey (USGS), the Energy Information Administration (EIA), the Minerals Management Service (MMS), and the Alaska Department of Natural Resources (ADNR). The resource estimates included in the record all utilized approaches that employed sound petroleum engineering principles and methodologies. Reserves can be estimated by many methods, and there may not be a consensus on which method is best to apply to an individual reservoir. Depending upon the data available and the degree of depletion for each reservoir, at least one of the

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48/ In view of the geographic isolation of Alaska and the Cook Inlet area from the rest of the United States, the Applicants asserted the question of general domestic or national need was not relevant. No intervenor challenged this assertion, and DOE concurs in it. Therefore, regional need is the only relevant need consideration.

following methodologies was used in the various analyses of Cook Inlet reservoirs: volumetric,[49/] material balance,[50/] decline curve,[51/] and analogy.[52/] The estimates sometimes employ different terms in specifying categories of resources. Both private and public data were used to varying degrees by the estimating organizations. The Applicants and ENSTAR used primarily public data, whereas Unocal, PGC, USGS, EIA, and the MMS have utilized substantial proprietary, as well as public, data.

To assist the reader in understanding the natural gas supply analysis in this Order, DOE compiled in Appendix A an alphabetical listing of natural gas reserves and resources categories and other terminology used in the various natural gas forecasts and assessments. **Table 1** on the next page is a summation of the natural gas reserves and resources assessments made by the parties, as well as ADNR, EIA, PGC, MMS, and USGS. **Table 1** also shows DOE's total natural gas resource estimate based on its findings in this Order. As discussed below and in Appendix A, not all of the parties or organizations represented on **Table 1** made estimates in every natural gas resource category, in which instance **Table 1** inserts "N/A" (for not applicable). ADNR and EIA, for example, estimate natural gas reserves, but not undiscovered possible resources, while PGC, MMS, and USGS estimate possible resources, but not proved reserves. However, the

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49/ A volumetric analysis considers the following reservoir elements in estimating reserves: area, thickness, water saturation, porosity, reservoir temperature, and reservoir pressure.

50/ The material balance approach compares changes in reservoir pressure to cumulative production in order to extrapolate an estimate of the amount of production that can be expected before assumed abandonment pressure is achieved.

51/ Decline curve analysis plots production rates of a gas well or group of wells against time to predict ultimate recovery.

52/ Analogy or analog analysis estimates the quantity of gas contained in an individual reservoir by comparing it to other nearby reservoirs which are similar in structure and provide a likely pattern of development.

TABLE 1
Gas Reserves and Resource Assessments of Cook Inlet, Alaska
Effective January 1, 1998
Billions of Cubic Feet (BCF)

	A	B	C	D	E	F	G	H	I
	Phillips/Marathon **(GeoQuest/Resource Decisions)**	***ADNR***	***EIA*** [3]	***Unocal*** [4]	***ENSTAR*** [5] **(MHA/Eason)**	***PGC*** [6] **(most likely)**	***MMS*** [7]	***USGS***	***DOE***
Discovered									
Proved Reserves									
Developed	2,490.5	2,947.0		2,276.0	2,150.2				
Undeveloped	858.9	119.0		528.0	285.9				
Total Proved	**3,349.4**	**3,066.0** [1]	**2,966.0**	**2,804.0**	**2,436.1**	N/A	N/A	N/A	**3,066.0**
Unproved Reserves									
Probable									
Non-Associated								685 [8]	685
Associated								353 [8]	353
Total Probable	**600.0**	100-600 [2]	N/A	933.0	**351.8**	1,050.0	N/A	1,038 [8]	**1,038**
Produced by 2009				**442.0**					
Undiscovered									
Unproved Reserves									
Possible									
Non-Associated								738 [9]	
Associated							900.0	647 [9]	
Technically Recoverable		N/A	N/A	432.0	1,385.0	2,100.0	900.0	1,385 [9]	
Economically Recoverable		N/A	N/A	**130.0**		N/A	0.0		
@ $2.00/MCF					**216.0**			441.0 [9]	**441.0**
@ $3.34/MCF								779.0 [9]	779.0
Speculative Resources	N/A	N/A	N/A	N/A	N/A	3,400.0			
Total Gas Supply	**3,949.4**			**3,376.0**	**3,003.9**				**4,545.0**

1 ADNR's April 1998 Report.
2 ADNR/Zobrist Report at 6.
3 Unocal's February 5, 1998, Comments at 8.
4 Unocal's December 22, 1997, Initial Comments, Exhibit A-1 at 17, 46, and 56.
5 ENSTAR's December 22, 1997, Comments at 10-14.
6 PGC's December 31, 1996, Report, Table 5. DOE assumed no change during 1997.
7 OCS Report MMS 96-0034, 32.
8 Appendix B to the Order at 5.
9 USGS Open File Report 95-75-J, 35-39.

Department has made estimates of the total natural gas resources available during the extension period for each category of natural gas.

Reserve estimates are based on interpretations of geologic and/or engineering data available at the time the estimates are made. Such estimates are inherently uncertain due to the nature of geological and engineering data, and the uncertainty of future technological developments and hydrocarbon prices. Thus, the determination of reserve estimates over the life of a typical field are routinely revised, as additional geologic, engineering, and performance data are obtained in the production and depletion of a field. Reserve estimates are also often modified as a result of changing economic conditions.

In general, reserve estimates are revised substantially upward over time as demand for gas increases and new exploration and development technologies become available.[53/] The most common factors taken into account by revised reserve estimates include:

1. Reservoir performance and pressure data
2. Continued development drilling
3. Advanced reservoir stimulation-fracturing, acidizing
4. Compression installation
5. Artificial lift installation
6. Secondary recovery operations
7. Operating economics - prices, costs, taxes
8. Regulatory changes
9. Improved seismic technology
10. Improved well completion

53/ *See, e.g.*, Emil D. Attanasi and David H. Root, *The Enigma of Oil and Gas Field Growth,* The American Association of Petroleum Geologists Bulletin (AAPGB), Vol. 78, No. 3, March 1994, 321-332; Root and Richard F. Mast, *Future Growth of Known Oil and Gas Fields*, AAPGB, Vol. 77, No. 3, March 1993, 479-484; *1995 National Assessment of United States Oil and Gas Resources*, USGS Circular 1118, 9; *Importance of Reserve Growth to the Nation's Supply of Natural Gas,* USGS Fact Sheet FS-202-96. *See also U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1997 Annual Report* (December 1998), DOE/EIA-0216(97).

These factors may materially affect both the estimates of hydrocarbons in-place and ultimate recovery.

Without any significant exploration activities in Cook Inlet since 1980, reserves have nonetheless continued to increase through reserve growth in existing fields. The amount of reserves growth can be determined, using data compiled by ADNR, by comparing the proved reserves at the beginning of 1980 (3,544 Bcf)[54/] with 6,730 Bcf, which is the total of proved reserves (3,066 Bcf) on January 1, 1998,[55/] plus cumulative production through 1997 (3,664 Bcf).[56/] This comparison shows an increase of over 3 Tcf of proved reserves through reserve growth in the 17 years and confirms that reserve growth in Cook Inlet mirrors the historical trend in reserve growth.[57/] Furthermore, this provides evidence reserves tend to increase over time, even without additional exploration, due to various factors, including those identified above.

b. **The Applicants**

The Applicants maintain they have demonstrated, through submitted studies, there are sufficient supplies of natural gas in the Cook Inlet area to meet the projected demand for both Alaska and their LNG export market through 2009.

The reserve estimates submitted by the Applicants were prepared by Schlumberger GeoQuest Reservoir Technologies (GeoQuest).[58/] Reserves, as well as potential resources, were

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54/ *See* Resource Decisions, Appendix C to the Application, at 4-3.

55/ *See* ADNR, *Historical and Projected Oil and Gas Consumption* (April 1998), at 4.

56/ *Id.* at 25-27. The 3,664 Bcf is the sum of net Cook Inlet natural gas production from 1980 through 1997.

57/ *See supra* note 53.

58/ *Supra* note 36.

also discussed by Resources Decisions and Northern Economics (Resource Decisions), the Applicants' other contractor.[59] The Applicants' submissions also contain comprehensive discussions of the analytical methods they used and rebuttals to the Protestors' comments. The proved reserve estimates submitted by the Applicants were higher than any others in the record for each category of proved reserves. The valuation methods employed (volumetrics and analogy, material balance calculations, and production performance extrapolation) adhere to generally recognized engineering standards.

GeoQuest did not have access to any proprietary information of the Applicants, but relied solely on publicly available data to assess proved developed and proved undeveloped reserves. Of the reserve estimates in the record, the GeoQuest study resulted in the highest values for proved undeveloped reserves, a category in which GeoQuest included behind pipe reserves and reserves from additional compression. The report prepared by Resource Decisions compared the GeoQuest values for proved developed reserves to those estimated by ADNR. The report concluded there were no major differences.

The Applicants discuss the PGC estimates of possible and speculative resources, but do not include these categories in their resource estimates. However, the Applicants do use the PGC 50 percent probability estimate for probable resources in their determination of potential resources.[60] The Applicants' Resource Decisions report discusses two cases as of January 1996: an "Expected Supply Case" and an "Unfavorable Supply Case". The Expected Supply Case uses

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59/ *Id*.

60/ *See* Potential Gas Committee (PGC), *Potential Supply of Natural Gas in the United States* (December 31, 1996). In estimating probable resources, PGC adjusts its estimates inversely with the likelihood, expressed in percentages, of recovery. Therefore, the amount of the probable resources estimate decreases as the likelihood of recovery increases.

the GeoQuest values for proved developed (2,928 Bcf)[61/] and proved undeveloped (859 Bcf)[62/] reserves and then adds the PGC 50 percent probability estimate of probable resources (1,050 Bcf)[63/] for a total of 4,837 Bcf. The Unfavorable Supply Case uses the ADNR proved developed reserves (2,784 Bcf)[64/] plus the GeoQuest proved undeveloped (859 Bcf)[65/] reserves along with the PGC's 100 percent probability estimate of 600 Bcf[66/] for a total of 4,243 Bcf.

For purposes of DOE's analysis in this Order, the Applicants' estimates were reduced by historical production to develop a January 1, 1998, value.[67/] The resulting reserve and resource estimates for the Applicants' expected case are 3,349 Bcf for proved reserves and 600 Bcf for probable resources. Thus, the expected total gas supply estimated by the Applicants is **3,949.4 Bcf** as of January 1, 1998 (**Table 1, Column A).**

c. The Protestors

ENSTAR and Unocal provided analyses of the natural gas supplies in the Cook Inlet. Aurora did not submit separate reserve/resource studies.

61/ Appendix D to the Application at 2-1.

62/ *Id.* at 2-2.

63/ *Supra* note 60, Table 55 at 104-105. The 1050 Bcf is the total of 650 Bcf (probable, most likely supply from Cook Inlet-Susitna) at 104, and 400 Bcf (probable, most likely supply from Cook Inlet offshore) at 105.

64/ *Supra* note 61, at 4-5.

65/ *Id.* at 2-2.

66/ *Supra* note 60. The 600 Bcf is the total of 400 Bcf (minimum probable supply from Cook Inlet-Susitna) at 104, and 200 Bcf (minimum probable supply from Cook Inlet offshore) at 105.

67/ As noted above, reserves historically tend to increase over time, so subtracting historic production from an earlier reserve estimate results in a conservative reserve estimate.

i. ENSTAR

ENSTAR commissioned studies by Malkewicz Hueni Associates (MHA) and James E. Eason (Eason) to determine Cook Inlet natural gas reserves and reserve additions anticipated from new discoveries through 2009.[68/] MHA relied on information and data obtained from public records to generate its reserve estimates and utilized material balance, volumetric, and decline curve analyses, in combination or separately, to evaluate the reserves for four of the largest fields in the Cook Inlet area. Those fields were the North Cook Inlet Unit, Beluga River, Kenai, and Beaver Creek Fields. MHA accepted the Applicants' reserve estimates for the McArthur River and Swanson River Hemlock Fields, as well as for certain undeveloped reserves. Most of the remaining Cook Inlet fields were analyzed based on material balance and decline curve methodologies.

The MHA analysis concluded the Cook Inlet fields contain 2,436.1 Bcf of proved gas reserves as of January 1, 1998.[69/] This proved reserve volume can be further subdivided into 2,150.2 Bcf of developed reserves and 285.9 Bcf of undeveloped reserves.[70/] The total proved reserves are significantly below the reserves estimated by the Applicants. The wide disparity in the estimates results from MHA's conclusion several of the key reservoirs of the larger fields have water influx (movement of water into the reservoir) as their drive mechanisms. Water influx, MHA concluded, allows several of the Cook Inlet reservoirs to maintain pressure, in turn overstating the volume of gas in place. This conclusion directly affects both the volume of

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68/ *Supra* notes 23 and 24.

69/ *Supra* note 23, at 9.

70/ *Id.*

MHA's reserves estimates and the classification of those reserves. MHA's proved reserve estimates, both developed and undeveloped, are substantially lower than other estimates in the record. The primary reason for this is the lower recovery efficiency expected for water drive reservoirs compared to a reservoir produced through pressure depletion.

Furthermore, reserves classified as proved in other analyses have been classified as unproved probable and unproved possible by MHA. For instance, MHA argued any recompletions in the Beluga formation of the Kenai Field would contain significant risk due to water influx, and MHA therefore classified this type of reserve as probable rather than proved undeveloped. MHA determined no recompletion potential exists in some of the reservoirs that may be already watered out or pressure depleted. Thus, some behind pipe reserves were omitted completely. Similarly, for the Tyonek Deep Reservoir in the Kenai Field, MHA concluded completion of additional wells will yield only accelerated production rather than any incremental reserves. The net effect is an overall reduction in the reserve estimates in all reserve categories.

As a result of its assumptions with respect to the production drive mechanism of the Cook Inlet reservoirs, MHA only classified 351.8 Bcf as unproved probable reserves (**Table 1, Column E**). This volume is comprised primarily of reserves attributed to the North Cook Inlet Unit, which are likely to be produced if the hypothesized water drive proved to be much weaker than expected. Only a relatively minor volume of probable reserves are attributed to any of the other Cook Inlet fields as a result of reserve growth.

The Eason study, a companion to the MHA reserves evaluation, assesses the potential reserve additions from undiscovered resources in the Cook Inlet. Eason's approach consisted of a review of exploration activities in the Cook Inlet and a literature review of published assessments of the potential undiscovered resources, including those prepared by the PGC, ADNR, USGS, and MMS. The Eason study eventually settled on the USGS undiscovered resources assessment as the basis for its estimate. However, Eason adjusted the USGS estimates to account for economics and the timing of discovery and development.

The USGS undiscovered resources assessment considers 738 Bcf of non-associated and 647 Bcf of associated gas resources to be technically recoverable in the Cook Inlet (**Table 1, Column H**).[71/] The USGS further estimates the volume of these resources that can be economically recoverable at a $2.00/Mcf gas price to be 120 Bcf (non-associated) and 321 Bcf (associated), for a total of 441 Bcf (**Table 1, Column H**). The Eason study gives full credit to the potential for the economically recoverable non-associated gas to be developed and added to the area's gas supply by the year 2009. With respect to the potential economically recoverable associated gas resources, Eason reduced the USGS estimate by 70 percent based on a relationship developed from historical data which to Eason indicated only an average of 30 percent of the total cumulative associated gas from Cook Inlet oil fields was produced during the first six years of production. Thus, the 321 Bcf was reduced to 96 Bcf to reflect this timing relationship. Eason characterizes the combined associated and non-associated gas resources of 216 Bcf as a reasonable "upside" potential for reserve additions from undiscovered fields in the Cook Inlet by the year 2009 (**Table 1, Column E**).

71/ Emil D. Attanasi and Ken J. Bird, *Economics and Undiscovered Conventional Oil and Gas Accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources: Alaska* (September 1996), USGS Open File Report 95-75-J, at 35.

Finally, by combining MHA's estimates of 2,436.1 Bcf in proved reserves and 351.8 Bcf in unproved probable reserves, with Eason's 216 Bcf estimate of undiscovered reserves, ENSTAR's total gas supply estimate is **3,003.9** Bcf as of January 1, 1998 **(Table 1, Column E**).

ii. <u>Unocal</u>

Unocal's discussions of gas reserves and resources included a comparison of all the estimates in the record, estimates which Unocal updated to January 1, 1998, by subtracting out historical 1996 and estimated 1997 production.[72/]

Unocal's proved reserves estimate is a combination of internal reserve estimates for the fields it operates, an analysis of the State of Alaska public information for select, major non-Unocal fields, and the ADNR estimates for the remainder of the non-Unocal operated fields. Unocal stated it applied a 1.00 risk factor to its estimates of proved reserves and a 0.50 risk factor to its estimates of unproved probable reserves. Unocal recognized a significant contribution to reserves could be expected from reserve growth and elected to use the PGC "Most Likely" estimate, 1,050 Bcf as of December 31, 1996, for this purpose.

Unocal then adjusted the 1996 PGC "Most Likely" estimate of 1,050 Bcf for unproved non-associated reserves to take into account unproved reserves that were reclassified as proved reserves through reserve growth during 1996 and 1997. (The inclusion of 1996 reserve growth is a questionable adjustment since the PGC "Most Likely" estimate was already current as of December 31, 1996.) Thus, it attributed 933 Bcf to reserve growth as of January 1, 1998 (**Table 1, Column D**). Of this volume, Unocal projected that 442 Bcf could be produced by 2009

72/ *See* Unocal's December 22, 1997, Initial Comments; *see also Reply Comments of Unocal Oil Company of California*, filed February 5, 1998.

(**Table 1, Column D**). Unocal estimated 130 Bcf of undiscovered field potential may be discovered by 2009 (**Table 1, Column D**). Unocal's methodology for determining these new or undiscovered resources reflected an adjustment of the median USGS estimate for technically recoverable, non-associated gas from 432 to 130 Bcf based on its assumptions regarding timing and drilling activity.[73/]

When Unocal added 2,804 Bcf of proved reserves, the Unocal-adjusted PGC "Most Likely" estimate for total unproved reserves of 933 Bcf, and the undiscovered resource of 432 Bcf, the Unocal total gas supply is stated as 4,169 Bcf, which it noted is higher than that claimed by the Applicants. This estimate does not include any associated gas except in the proved reserves category. However, if the "timing" issue is considered, which Unocal views as imperative, a different picture emerges. To address the timing issue, Unocal added 2,804 Bcf of proved reserves, the Unocal-adjusted PGC "Most Likely" estimate for unproved reserves of 442 Bcf which will be produced by 2009, and undiscovered "timed" (i.e., economically recoverable) resource of 130 Bcf. Under this scenario, Unocal estimates a total resource potential of **3,376 Bcf** to be available during the five-year export extension period (**Table 1, Column D**), significantly lower than its 4,169 Bcf estimate of the total gas supply.

d. Findings

Our determination on the issue of total, recoverable gas supply available over the course of the requested extension period follows a thorough review of the extensive record in this case, including data in the (1) studies submitted by all of the parties, studies which in turn use (2) a variety of reports by Federal, State, and other agencies and organizations, as well as (3) other

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73/ *Id.*

published reports. **Appendix B** includes brief descriptions of documents/reports on this subject prepared by ADNR, EIA, PGC, USGS, and MMS. Attached to Appendix B are two tables providing proved reserves estimates as of January 1, 1996, and January 1, 1998 (Tables B-1 and B-2). **Appendix C** is a USGS summary of published USGS estimates of Cook Inlet reserves.

ENSTAR and Unocal raised supply-related questions primarily regarding water influx and associated gas. The Department considered these two issues carefully. As noted above, ENSTAR's water influx issue is the one which produces the greatest disparity in reserve estimates. We believe the reservoirs are compartmentalized and too discontinuous to permit a significant water drive to exist, and conclude water influx is not and will not be a major factor in reservoir performance.[74/] Given the discontinuous nature of the Cook Inlet reservoirs, the Department finds the relatively minor observed water production in various Cook Inlet gas fields is not indicative of contact with an unlimited aquifer. Rather, it may be due to the mobility of interstitial water from changes in relative permeability, production from behind pipe as a result of poor completion jobs, and, to a much lesser extent, from condensation of bound water vapor and production from isolated water pockets. Therefore, DOE does not accept MHA's proved reserve estimates based on its water influx analysis.

74/ Theoretically, DOE agrees reservoirs supported by a water drive production mechanism cannot be analyzed in the same manner as a strictly volumetric or closed reservoir that is produced through pressure depletion. Material balance calculations yield accurate reserve estimates when applied appropriately to volumetric reservoirs. However, when water drive, or influx, is present, the encroaching water also supplies energy to the reservoir, thereby reducing the rate of pressure depletion. In these circumstances, a material balance analysis of the reservoir tends to overstate reserves because the water influx energy is mistaken for a larger volume of gas in place.

In such situations, where water influx has been identified through geologic and/or production evidence, DOE believes the material balance approach can still be useful provided appropriate modifications are made to the analysis. Additionally, if water influx is present, water will eventually find its way to the producing well bores. This will require higher pressures to lift water and thus result in either higher abandonment pressures for the reservoirs or increased lifting and water handling costs. In other words, for any reservoir subject to water influx, recovery efficiencies (and hence, reserves) will be lower than for a reservoir produced through pressure depletion.

With respect to associated gas, Unocal did not include associated gas in its supply estimate, contending associated gas is not available for production since it is often reinjected to optimize oil production. DOE considers associated gas a part of the entire resource base that will eventually be produced at the end of the oil production period, as well as during gas cap blow-down. Thus, availability of associated gas is a matter of timing and economics, rather than the volume of available resource.

Table 1 shows proved gas reserve assessments for Cook Inlet as of January 1, 1998, prepared by the Applicants (GeoQuest), ADNR, EIA, Unocal, and ENSTAR (MHA). With the exception of the Applicants' and ENSTAR's estimates, the reserve assessments fall within a relatively narrow band around 3,000 Bcf. The MHA assessment of 2,436.1 Bcf is based on its water-influx analysis which DOE has rejected. The Applicants' assessment of 3,349.4 Bcf is about 12 percent higher than the median. Reserve assessments are not exercises in taking inventory, but rather estimates based on the available knowledge of reserve characteristics. Therefore, it is not unusual to find, and DOE is not surprised by, differences in the reserve assessments. On the contrary, what is significant is the uniformity, particularly in the ADNR, EIA, and Unocal assessments.

We used the ADNR proved reserves estimate in our estimate of the Cook Inlet gas supply for the export extension period. The most recent ADNR estimates of hydrocarbon reserves are included in its annual update (published in April 1998) of a report entitled *Historical and Projected Oil and Gas Consumption*. This report provides an independent, unbiased estimate of proved reserves. All Cook Inlet reserves are on State land with the exception of Swanson River, Beaver Creek and Birch Hill Fields and parts of Beluga River, Kenai and Cannery Loop Fields.

The State’s royalty reserves are calculated by multiplying each field’s reserves times the State's interest in the field. As a result, the State seeks accurate reserve estimates to ensure its planning efforts are directed appropriately. Therefore, DOE believes it is reasonable to rely on the ADNR’s proved reserve determination of 3,066 Bcf as of January 1, 1998, for the Cook Inlet area as an accurate, impartial estimate of proved reserves (**Table 1, Column B**).

The ADNR proved reserve estimate is confirmed by the EIA assessment 2,957 Bcf of non-associated gas reserves as of December 31, 1997.[75/] EIA does not report the amount of associated gas reserves for the Cook Inlet; however, we acknowledge the volume is relatively minor. Furthermore, we have assumed all non-associated gas reported by EIA is located in the Cook Inlet area. As explained in Unocal's February 5, 1998, filing, the EIA field-by-field reserve estimates are filed on a confidential basis by producers in compliance with Security and Exchange Commission requirements, and, therefore, the EIA data can be assumed to be credible. Moreover, EIA is an independent analytical and statistical agency within DOE whose estimates have been cited or relied upon by the parties in the case, and it is appropriate for DOE to rely on EIA's expertise in making decisions on available gas supplies. The aggregate EIA data corroborate the ADNR estimates. Comparison of the EIA non-associated proved reserve estimate (2,957 Bcf) to the ADNR estimate (3,066 Bcf) illustrates this point (an approximate difference of less than 4 percent).

DOE's natural gas resource estimate adds to the ADNR proved reserves the USGS estimates for probable reserve growth and for the potential economically recoverable gas from undiscovered fields. USGS, like ADNR, is an independent, unbiased, governmental agency

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75/ *See* EIA's December 1998 report, *supra* note 53, Table 10 at 32.

whose estimates have been cited and relied upon by the parties in the case. The USGS estimate for probable associated and non-associated reserve growth, as adjusted by DOE, is 1,038 Bcf (**Table 1, Column H**).[76/] The economically recoverable gas from undiscovered fields is 441 Bcf based on a gas price of $2.00/Mcf for the Cook Inlet (**Table 1, Column H**). EIA projects a lower-48 States wellhead price of $2.27 per Mcf for natural gas in the year 2009. While EIA does not publish a price for the Cook Inlet, these prices have been historically less than the average lower-48 States price and, therefore, a price of $2.00 per Mcf for the Cook Inlet is assumed to be a reasonable forecast.

By combining the ADNR proved reserve estimate of 3,066 Bcf with the USGS probable reserve growth estimate of 1,038 Bcf, as well as the USGS estimate of 441 Bcf for recoverable gas from undiscovered fields (based on a price of $2.00/Mcf), DOE estimates the total volume of natural gas reserves and resources available to be produced in the Cook Inlet area between 1998 and 2009 is **4,545 Bcf** (**Table 1, Column I**).[77/]

In addition to the conventional gas resources discussed above, DOE considered other potential sources of natural gas available to southcentral Alaska. Because the record demonstrates there are more than sufficient conventional gas supplies, DOE did not include these other potential gas sources in its aggregate resource estimates or rely on them in reaching its decision in this Order, but they represent significant, potential sources of future supplies. As

76/ For the derivation of this number, see Appendix B to the Order at 5.

77/ DOE is aware combining proved reserve estimates with unproved resource estimates for aggregate figures, when there are different levels of certainty associated with each category, could create a false sense of certainty regarding the unproved resources. *See* the Society of Petroleum Engineers (SPE)/World Petroleum Congress (WPC) standards, cited in the ENSTAR/MHA report, *supra* note 23, at 12. However, it is appropriate to do so in this instance because the purpose of this evaluation is to determine the total volume of resources expected to be available in the Cook Inlet area through 2009.

discussed below, perhaps the most important of these are the Cook Inlet coal resources with their potential for the production of coalbed methane.

Commercial production of gas from coal is a relatively new development. Only a decade ago supplies of coalbed methane were virtually nonexistent. Today, coalbed formations contribute more than 1 Tcf or roughly six percent of dry gas production in the lower-48 States.[78/] Although coalbed methane is not yet commercially produced in Alaska, various studies indicate this source of supply is a viable alternative given the right market incentives. One comprehensive study on the potential of Alaska coalbed methane concluded Alaska coal could contain up to 1,000 Tcf of natural gas.[79/] Another study of coalbeds in the Cook Inlet area by the USGS estimates bituminous coal at shallow depths and the methane gas problems associated with mining combine to make the area a high prospect for coalbed methane production.[80/] The Cook Inlet area has in excess of 1.5 trillion short tons of coal, and the properties of the coal are very similar to those of Wyoming's Powder River Basin, where commercial production of methane has already been established.[81/]

The relatively low prices for natural gas in the Cook Inlet area seem to have been the main reason for the lack of interest in the exploration and development of the coalbed methane resource. However, the prospects for commercial production of coalbed methane in the Cook

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78/ EIA's December 1998 report, note 53, at 34-35.

79/ T.N. Smith, ADNR, *Coalbed Methane Potential and Drilling Results for the Upper Cook Inlet Basin* (May 1995).

80/ B.F. Barnes and T.G. Payne, *The Wishbone Hill District, Matanuska Coal Field, Alaska*, USGS Bulletin 1016.

81/ *Supra* note 79, at 4.

Inlet area appear to have improved significantly in light of industry activities over the past couple of years. In fact, there are increasing signs that production of coalbed methane in the Cook Inlet area may occur in the not so distant future. In this regard, we note the March 1998 ADNR approval of a Unocal-sponsored unit agreement for the exploration and identification of Cook Inlet coalbed methane.[82/] This unit contains an estimated 3.6 Tcf of coalbed gas in place, which, at a 40 percent recovery rate, is equivalent to potential reserves of 1.4 Tcf.[83/]

Another possible source of Cook Inlet gas supplies are very low permeability, tight sand formations. They are known to exist, but are not practical for commercial development at this time, given the greater potential from coalbed methane.

Finally, the Alaska North Slope contains in excess of an estimated 26 Tcf of recoverable natural gas.[84/] A pipeline carrying North Slope gas to the Cook Inlet area has been proposed, but

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82/ On March 31, 1998, ADNR approved Unocal's Pioneer Unit Agreement, which covers 72,605 acres located in the northeastern corner of the Cook Inlet Basin near the towns of Houston and Wasilla. Unocal anticipates initial testing of three unit wells will be completed by September 1999 and any long-term testing will be completed by March 2001.

83/ *The Funding Challenge*, PETROLEUM NEWS ALASKA, November 30-December 28, 1998, Vol. 3, No. 11. The area is said to have extensive infrastructure, to be accessible to drilling and within five miles of a 20-inch pipeline. In another Cook Inlet coalbed methane project, GRI Inc. recently drilled four wells near the town of Houston expecting to find 80 feet of coal in a 2,000-foot well, but actually found a 200-foot coal seam. As a result of this success, GRI is expanding its drilling program. *GRI Pleased with Houston Results*, PETROLEUM NEWS ALASKA, October 26-November 29, 1998, Vol. 3, No. 10, at 10.

84/ Alaska North Slope gas refers to natural gas derived from the area of the State of Alaska north of the Brooks Range, including the continental shelf of the United States under the Beaufort Sea.

may not be completed before 2009.[85/] However, during 1997 and 1998 Alaska enacted legislation designed to improve the economic feasibility and competitiveness of a North Slope gas project.[86/]

Although the Alaska North Slope and unconventional gas resources have vast potential, and the above-referenced legislative and drilling initiatives demonstrate the considerable interest in developing these resources, DOE did not include them in its supply estimate for this Order. They were omitted in part because it is unclear how significantly they might contribute to natural gas supply in the Cook Inlet area during the five-year extension period, but, more important, because the available supply of conventional gas is sufficient to meet both domestic and export demand.

2. Cook Inlet Natural Gas Demand

a. Introduction

In order to assess anticipated demand for regional gas supplies during the proposed 2004-2009 extension, the Department considered historical consumption data for the Cook Inlet area and demand forecasts submitted by the parties and contained in reports published by ADNR. In this section DOE reviews these historical and projected demand figures. The projections are inherently simplistic and understate the complicated interdependence between supply and demand,

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85/ *See supra* note 2. On April 17, 1998, the Federal Energy Regulatory Commission (FERC) granted a motion filed by Yukon Pacific on March 17, 1998, to extend through May 22, 2001, the time within which Yukon Pacific may commence construction of its LNG export facilities at Anderson Bay, Port Valdez, Alaska, authorized by FERC in Docket No. CP88-105-000. This LNG plant would liquefy natural gas received from Yukon Pacific's proposed 800-mile pipeline (TAGS) originating on the North Slope.

86/ On June 18, 1998, the State passed the Alaska Stranded Gas Development Act, ALASKA STAT. § 43.82.010 *et seq.*, which allows project sponsors to negotiate with the State those terms and conditions over which the State has control, including taxes, royalties, lease terms, and socioeconomic assistance. The State had previously established the North Slope Commercialization Team to work with potential project sponsors to identify and recommend changes to State law to improve project feasibility. *See* the 1997 ALASKA SESS. LAWS CH. 76.

a "chicken and egg" relationship noted in an ADNR study by petroleum economist Daniel H. Zobrist (Zobrist report).[87/] In the context of analyzing potential in-state demand for Alaskan North Slope gas, the Zobrist report characterizes Cook Inlet demand as the driving force behind Alaskan North Slope gas sales, while at the same time noting the interdependency of actual Cook Inlet demand, the deliverability of Cook Inlet fields, current reserve levels, and the success of exploration efforts.[88/]

b. The Applicants

The Applicants submitted a demand (and supply) analysis prepared by Resource Decisions.[89/] Relying on 1995 demographic projections prepared by the Institute of Social and Economic Research (ISER) at the University of Alaska in Anchorage,[90/] Resource Decisions estimated demand for Cook Inlet gas through 2009 for both an expected (base) case and a pessimistic (high demand) case.[91/]

The Resource Decisions expected case scenario shows annual gas demand reaching 204.87 Bcf in 1998 and then declining slightly over the next eleven years to 201 Bcf in 2009. This is an overall decline of about 3.9 Bcf, or almost 2 percent. Under this scenario, demand for

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87/ *See The Potential In-State Demand for Alaska North Slope Gas* (October 1, 1997), prepared for the RIK/RIV Committee of the North Slope Gas Commercialization Team, at 1. The published Zobrist report is referenced in the *Reply Comments of Phillips Alaska Natural Gas Corporation and Marathon Oil Company to Initial Comments of ENSTAR Natural Gas Company, Union Oil Company of California, and Aurora Power Resources, Inc.*, filed February 5, 1998, note 47 at 22. *See also* Julius and Mashayekhi, *supra* note 29, Part IV.

88/ *Id.*

89/ *Supra* note 36.

90/ ISER, *Economic Projections: Alaska and the Southern Railbelt 1995-2025* (1995). The study originally was prepared for Chugach Electric Association to assist in its long-term planning.

91/ *See supra* note 36, Tables 3-6 and 3-7 at 3-14. The Applicants maintain no significant economic or demographic changes have occurred to affect the validity of the two forecasts.

both electricity generation and gas utilities grows by 15.6 percent over the forecast period. This forecast does not anticipate any new large projects and consumption by both the LNG and fertilizer plants, the two largest demand sectors, remains constant during the entire forecast period. However, Resource Decisions predicts gas use in field operations will decline substantially as a result of oil field depletion (from 12.71 Bcf in 1998 to zero by 2007). Under the expected case forecast, cumulative natural gas demand from 1998 through 2009 is **2,424 Bcf.**

The biggest difference between the Resource Decisions expected and pessimistic demand forecasts is the growth in natural gas demand for both electricity generation and gas utilities (a combined 39.5 percent over the forecast period), an increase attributed to population and economic growth. The pessimistic demand scenario also evidences a slower decline in annual consumption for field operations (declining from 14.16 Bcf in 1998 to 5.17 Bcf by 2009). Under the pessimistic demand forecast, cumulative natural gas demand from 1998 through 2009 is **2,613 Bcf.**

c. The Protestors

ENSTAR retained ISER to prepare gas demand projections.[92/] ISER developed base, high and low cases.[93/] ENSTAR's base, or expected, demand scenario for 1998-2009 is **2,631 Bcf.**[94/] Annual gas consumption for power generation and by gas utilities is expected to increase by 15.1

92/ ENSTAR was the only protestor to submit independent demand projections. Unocal adopted the ENSTAR demand projections. Aurora did not address demand separately.

93/ *See Motion to Intervene and Protest of ENSTAR Natural Gas Company*, filed April 3, 1997, at 41-43 and Table 7. A subsequent ISER analysis updated the forecasts. *See* Appendix D to ENSTAR's December 22, 1997, Comments, *supra* note 25. The Department is not considering ENSTAR's low demand scenario in this analysis since it is only marginally less than the base case.

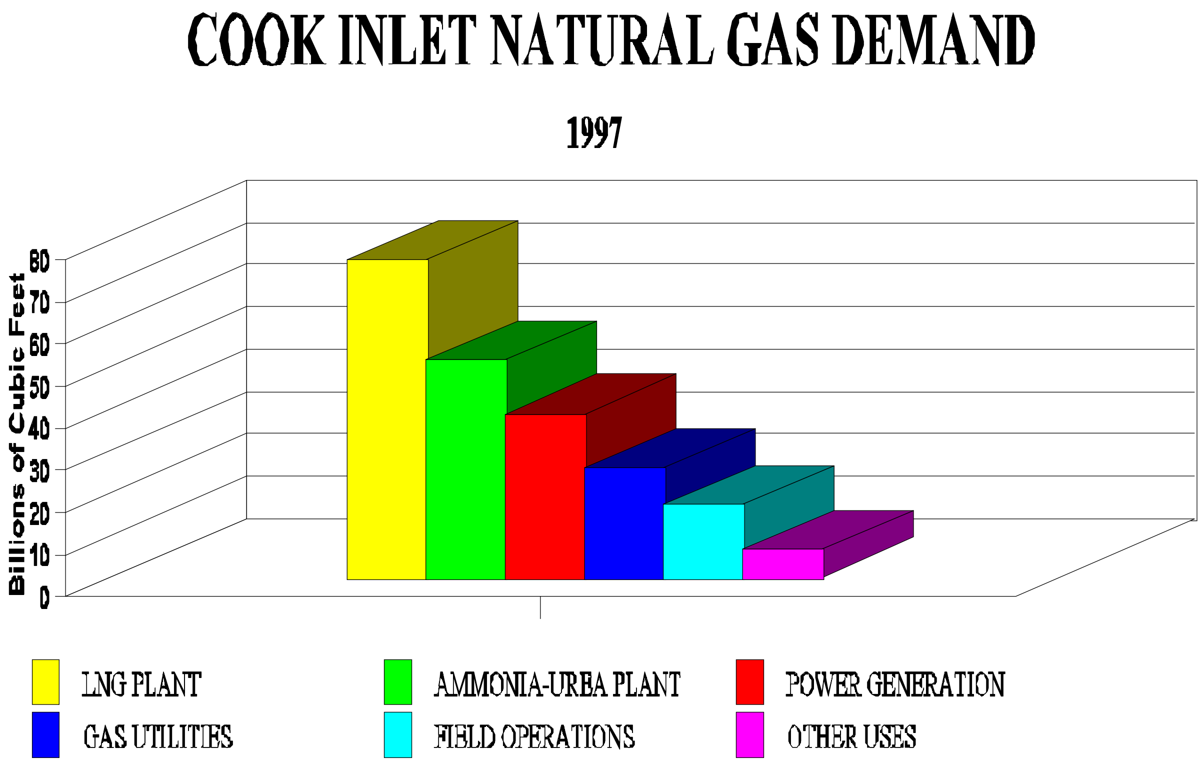
94/ DOE adjusted the forecasts to extend consumption by the Applicants' LNG plant through the 4th quarter of 2009.

and 26.4 percent, respectively. Under this scenario, the only new use of gas in the forecast period involves the trucking of LNG to Fairbanks. This project became operational in April 1998 and ENSTAR projects it will increase total demand by 3.15 Bcf in 2009. Gas demand by the two largest users of Cook Inlet gas production, the LNG plant and the ammonia-urea fertilizer plant, is expected to experience no growth during this period. In addition, ENSTAR forecasts a nearly 60 percent decline in gas used in field operations.

In the ENSTAR/ISER high demand scenario, cumulative gas consumption from 1998 through 2009 totals **3,104 Bcf**. Additional gas consumption in the high case is due primarily to two new uses not reflected in ENSTAR's base case. The first use is in a proposed iron ore reduction plant to be located near Tyonek, Alaska, and the second a proposal to provide gas in the form of LNG to remote coastal communities in southeast Alaska. In addition to the two new uses, the high demand case projects robust growth in demand by the utility generation and gas utilities categories.

d. <u>ADNR</u>

As noted in the preceding supply section of this Order, the Division of Oil and Gas of the ADNR prepares an annual report which provides historical and projected oil and natural gas demand data for the State of Alaska, including separate breakdowns of the North Slope and the Cook Inlet area. ADNR is the official State of Alaska agency charged with making demand projections. The Department therefore concluded it was appropriate to consider ADNR's demand projections in its assessment of regional need, and has made ADNR's projections part of the record in this proceeding. The latest of these reports was published in April 1998 and, like the



demand forecasts submitted by the parties, takes into account ISER economic and demographic projections.[95/]

ADNR's 1998 annual report provides a 1997 market profile, illustrated above, for natural gas production from Cook Inlet.

95/ ADNR April 1998 Report.

Of the approximate 214 Bcf of gas consumed in 1997, 35 percent went to the Applicants' LNG plant for combined fuel use and product; 24 percent was utilized by Unocal's ammonia-urea plant for combined fuel use and feedstock; 18 percent went to power generation; 12 percent was sold to gas utilities; 8 percent was used in field operations (gas consumed in producing oil and gas from Cook Inlet); and 3 percent to other uses.[96/] The gas usage breakdown by customer class has remained relatively constant over the past twenty years, the biggest change a steady but modest increase in utility gas consumption (growing from 7 percent of total gas consumption in 1978 to 12 percent in 1997).[97/]

The usage breakdown is expected to remain constant through ADNR's forecast period (1998-2008), with the exception of the LNG exports, which drop to zero after the first quarter of 2004 when the Applicants' current export authorization expires.[98/] For purposes of its demand analysis in this docket, DOE adjusted the ADNR forecast to add gas consumed by the Applicants' LNG plant during the extension period. We also extended all uses through 2009, employing ADNR's same trend lines, so that its consumption forecast could be compared with the projections provided by the Applicants and ENSTAR.

The ADNR projections show only modest growth in natural gas demand from 1998 through 2009, an increase, as adjusted by DOE, of approximately 12 Bcf, or slightly over 5 percent. Gas consumption by the power generation and gas utility sectors is projected to experience slow steady growth during the forecast period, but the two largest users of Cook Inlet

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96/ *Id.*, Table 6 at 36. Annual export deliveries of 64.4 Bcf to Japan require approximately 78 Bcf for LNG plant feedstock and boil-off during shipping, *infra* at 41.

97/ *Id.*,Table 6 at 34-36.

98/ *Id.*, Table 7B at 43.

gas production, the LNG and the ammonia-urea fertilizer plants, are not expected to experience any growth. The only new use of gas in the ADNR forecast period is the LNG trucked to Fairbanks, a use expected to consume no more than 0.5 Bcf annually through the forecast period.

As adjusted and extended, the ADNR forecast of cumulative natural gas demand for the Cook Inlet area from 1998 through 2009 is **2,753 Bcf.**

e. Findings

As in our determination of total gas supply, DOE's determination on the issue of total gas demand over the course of the requested extension period is based on the totality of the extensive record compiled in this proceeding.

Table 2 on the next page shows, in ascending order, the cumulative demand projections for the Applicants' expected and pessimistic cases, ENSTAR'S base case, ADNR's forecast, and ENSTAR's high case. The last column in **Table 2** is DOE's demand estimate. DOE's estimate is based on ENSTAR's high case with certain modifications discussed below. In general, the Applicants assume no new uses for gas in either their expected or pessimistic cases; ADNR assumes negligible consumption of LNG trucked into Fairbanks; and ENSTAR assumes a more rapid penetration of the Fairbanks market by LNG in its base case and new LNG use in coastal areas and consumption in a proposed new iron ore reduction plant in its high demand case.

Table 2

CUMULATIVE NATURAL GAS DEMAND PROJECTIONS FOR SOUTHCENTRAL ALASKA FOR THE YEARS 1998 - 2009 (Bcf)						
	Applicants Expected Case	**Applicants Pessimistic Case**	**ENSTAR Base Case (As Adjusted by DOE)**	**ADNR (As Adjusted by DOE)**	**ENSTAR High Case**	**DOE****
Power Generation	433	484	457	469	522	522
Utility Gas*	344	386	385	395	442	442
LNG Manufacturing	922	978	945	936	978	978
Urea Manufacturing	648	648	656	660	656	656
Field Operations	78	116	125	224	176	176
New Uses	0	0	19	5	286	29
Unaccounted for	0	0	44	64	44	44
TOTAL	2,424	2,612	2,631	2,753	3,104	2,847

* In the Applicants' analyses, utility gas for military use has been shifted to power generation to be consistent with the ENSTAR categories.

** DOE is using ENSTAR's pessimistic case adjusted to exclude gas usage attributed to the iron ore reduction plant and LNG sales to coastal communities.

Regarding ENSTAR's high demand case, DOE agrees with the Applicants, and with ADNR, the iron ore reduction plant and the proposal to provide LNG to coastal communities are unlikely to materialize without long-term, low-priced contracts.[99/] In any case, they are highly speculative at this point and it is clearly not in the public interest for the Department to consider such speculative future uses of gas when making a decision on extending an authorization for an ongoing, long-established, actual use. After excluding the 259 Bcf attributable to the iron ore reduction plant and LNG use by coastal communities, the adjusted ENSTAR high demand case is **2,847 Bcf**.

99/ *See* the Applicants' May 9, 1997, Answer at 96; *see also* Zobrist, *supra* note 87, at 8.

The adjusted ENSTAR estimate is higher than either the Applicants' base or pessimistic cases, as well as ADNR's forecast, but still falls within a reasonable range when compared to the other demand estimates. Indeed, it is only 2.5 percent higher than ADNR's forecast. DOE found all of the demand forecasts reasonable, and their close correspondence is not surprising since they were all based on ISER demographic projections.

3. Additional Regional Need Issues

As discussed previously in this Order, DOE estimates the total natural gas resources available in the Cook Inlet area through the export extension period to be **4,545 Bcf** (**Table 1, Column I**). Furthermore, DOE estimates total demand for gas in Cook Inlet through 2009 to be **2,847 Bcf** (**Table 2, last column**). Therefore, there are more than adequate regional natural gas supplies to meet the anticipated local and export demand. However, the Protestors raised a number of issues which they claim will cause supply shortfalls regardless of the total volume of conventional gas resources available for production.

Some of these issues involve limitations on the physical ability of established Cook Inlet fields to produce gas from reserves in sufficient quantities to meet demand and of the existing gas infrastructure to deliver it. These are the so-called "deliverability" (as opposed to resource base) issues. In addition, the Protestors raised various economic/contractual issues which they claim need to be considered in a regional need analysis.

a. <u>Deliverability Constraints</u>

The Applicants, Unocal, and ENSTAR submitted deliverability forecasts which are included in the record and described in **Appendix D**.[100] These deliverability forecasts rely, consistent with widely accepted industry practice, on some combination of (1) calculated well production capacities, derived from various pressure measurements, (2) decline curve analysis, and (3) material balance methodologies, to estimate Cook Inlet natural gas deliverability.[101] The forecasted supply shortfalls in these deliverability studies are a function of (1) demand scenarios, (2) proved reserves estimates, (3) additional gas resources (beyond proved reserves) assumed to be available, and (4) the aggressiveness of the exploration and development programs on which the analyses rest. Gas demand projections and estimates of proved reserves are reasonably consistent between the parties. The big disparity in the deliverability forecasts arises primarily from the last two factors, *i.e.*, differences in estimates of the more speculative components of the gas resource mix (reserve growth and undiscovered gas fields), and in the parties' conclusions, implicit or explicit, regarding the industry's incentives and ability to bring the gas on line to meet demand.

In addition to the field production issues raised in the deliverability forecasts, the Protestors have asserted systems constraints (bottlenecks in gathering, processing, storage, or

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100/ DOE also considered the ADNR/Zobrist report, *supra* note 87.

101/ Unocal uses a system approach for its analysis. None of the parties' well capacity estimates take into account flow restrictions introduced by surface facilities.

transportation systems) "could constrain the capacity to fill demand," and should be considered in a regional need analysis.[102/]

As noted earlier, section 3 of the NGA creates a presumption in favor of approval of an export application.[103/] In evaluating an export application, DOE applies the principles described in the Secretary's natural gas import policy guidelines[104/] which presume the normal functioning of the competitive market will benefit the public.

Regarding the field development and other infrastructure constraints raised by the Protestors, we agree with the Applicants that deliverability from what DOE has determined is an "adequate reserve base is [ultimately] largely a function...of competitive market forces."[105/] DOE believes that as (and if) gas markets further develop in Alaska, and economics and technology support exploration and development, the Cook Inlet area's gas reserves and the corresponding infrastructure will increase.[106/] This is exactly what has occurred in the lower-48 States this decade when natural gas consumption increased by 17 percent and marketed production increased by six percent since 1990. In its May 1998 report, EIA noted

> [L]ower-48 gas reserves increased to 156 Tcf in 1996, making the third consecutive year of higher reserve levels although still slightly below the 1990 level of 160 Tcf. This recent trend is expected to continue. Various

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102/ Unocal's February 5, 1998, Comments at 46, and May 15, 1998, Comments at 18.

103/ *See supra* note 42.

104/ *See* 49 Fed. Reg. 6684, February 22, 1984.

105/ The Applicant's February 5, 1998, Reply Comments, note 152, at 90.

106/ The oil embargoes of the 1970's illustrate the ability of the domestic petroleum industry to respond to market conditions with accelerated exploration and production activity. The embargoes put pressure on domestic supplies and prices increased. The drilling rig count, as one measure of exploration and production activity, increased rapidly from a low of about one 1,000 active rigs in the early 1970's to about 4,500 rigs in the year 1981 (*see* Baker Hughes North American Rotary Rig Counts).

> factors, such as improved well completions, advanced stimulation technology, and improved seismic technology, have allowed producers to maximize gas output from existing fields, resulting in a decline in the ratio of reserves to production since 1990.[107/]

The arguments advanced by the Protestors, based on current Cook Inlet market characteristics, to question the market's ability to deliver sufficient supplies to meet future demand in fact illustrate the efficient operation of that market. The Protestors point to the fact that "over the past 19 years, only 205 Bcf of reserves have been added through new pool and field discoveries and extensions."[108/] To DOE this does not demonstrate gas resources cannot be brought on-line in a timely manner to supply demand. Rather, it is an indication the market is operating efficiently. Demand for gas in Cook Inlet has been stable for many years with only limited incremental growth, and reserve production has met demand. Therefore, to date, there has been no reason for more extensive exploration and development activities. DOE's projections of cumulative demand for 1998-2009 (Table 2) anticipate the continuation of stable demand levels in Cook Inlet. Under these circumstances, and given the total resource base available, the normal working of a competitive market will ensure the timely development of both resources and infrastructure. Similarly, the argument that the thin margin between actual production and production capacity indicates a probability of a shortfall[109/] merely proves the point that in a stable demand situation, such as has existed in Cook Inlet, the market produces closely correlated actual production to delivery capacities to maximize efficiency.

107/ *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98), at 11.

108/ *Comments of Union Oil Company of California on Applicants' "Clarifications" to Deliverability Analysis,* filed May 15, 1998, at 14.

109/ Unocal's February 5, 1998, Comments at 47.

b. Economic/Contractual Issues

The Protestors raised economic or contractual issues which they claim should affect DOE's regional need analysis. Some of these issues, such as the price necessary to spur further exploration and development of Cook Inlet gas resources,[110/] and regional demand growth,[111/] have already been addressed in the supply and demand subsections of this section on regional need. We will discuss two others briefly here. The first is the possibility producers may shut in their gas supplies and not deliver them to meet market demand.[112/] As an example, Unocal notes, "although Phillips controls more than 30 percent of Cook Inlet reserves, they do not sell any gas to domestic consumers" and has made no commitment to release these reserves to Alaska's consumers.[113/]

DOE does not believe this is a valid concern. With respect generally to producer shut-ins, DOE assumes producers will act rationally in their own economic best interest and will produce and sell gas in response to a demand for gas at a reasonable price.

Regarding PANGC in particular, it has always used its reserves for its export customers. As long as there are adequate supplies to meet both domestic and export demand there is no sound policy reason for DOE to look at whose gas is going to which market. American short-story writer O. Henry would appreciate the irony of a natural gas producer unable to obtain authorization to export its gas unless it first committed to sell that gas to domestic consumers, in

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110/ *Id*. at 48.

111/ *Id*. at 50.

112/ *Id*. at 47. Unocal included this issue as one of its arguments regarding deliverability, but since it does not deal with physical limitations on gas deliveries, DOE thinks it is more properly addressed as an economic issue.

113/ *Id*.

which case it would have no gas to export. It is possible a supply-to-demand ratio so dire as to threaten vital domestic uses might compel DOE to conclude an export of gas is not in the public interest. But that situation does not exist here, and it is not in the public interest for DOE to interfere with the normal workings of a competitive market by requiring an exporter to give contract priority to domestic consumers.

The second issue involves contract priority. Unocal argues the long-term contracts most current users already have in place, which the Applicants claim will limit incremental demand for gas, do not provide sufficient protection to the buyers to ensure they will receive the contracted for supplies over the length of the contracts.[114/] To illustrate its point, Unocal cites a no warranty of reserves clause in the 1988 Marathon-Chugach Electric Association, Inc. (Chugach) supply contract which obligates Marathon to supply Chugach only to the extent Marathon's gas reserves are adequate to supply Chugach without impairing Marathon's ability to meet other supply commitments, including its LNG export volumes.[115/] In addition, Unocal cites another contract clause which allows Marathon to reduce its delivery of gas to Chugach upon five years advance notice.[116/]

Regarding the priority of delivery clause, the existence of this clause does not indicate a regional need for the exported gas and DOE does not believe it should interfere with the rights of market participants to negotiate and agree to contract terms. On the delivery reduction clause, DOE does not accept the contention a contract provision which allows the natural gas supplier to

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114/ *Id.* at 51.

115/ *Id*. at 52.

116/ *Id*.

reduce deliveries only after a five-year notice period constitutes an indication the supplier is not committed to the long-term delivery of gas. To the contrary, such a long notice period supports the Applicants' contention consumers have firm supply commitments.

4. <u>Conclusion</u>

DOE finds the export extension will not adversely affect domestic gas use in the Cook Inlet area and there is no domestic need for the gas to be exported. DOE estimates the total gas resources available for production over the course of the extension period to be **4,545 Bcf** (**Table 1, Column I**), and the total estimated demand to be **2,847 Bcf** (**Table 2, last column**). However, even using the supply and demand estimates of the Protestors, DOE nevertheless concludes supply is more than sufficient to meet demand. A review of the supply and demand estimates in Tables 1 and 2, respectively, illustrates this point. The lowest supply estimate is ENSTAR's at 3,003.9 Bcf, and the highest demand is ENSTAR's high case at 3,104 Bcf. Given the vagaries of supply and demand estimates, this 3 percent differential essentially shows a balanced supply and demand ratio. Moreover, as discussed earlier, DOE does not consider ENSTAR's water influx argument valid and therefore does not accept its supply estimate. The other supply estimate submitted by a Protestor is Unocal's, which, at 3,376 Bcf, exceeds ENSTAR's high demand case by 272 Bcf. In addition, DOE finds the arguments made by the Protestors regarding deliverability constraints and other economic and contractual issues do not alter the basic supply to demand balance which leads to the inevitable conclusion there are adequate supplies to meet both domestic and export demand during the extension period. DOE is at a loss to understand the Protestors' contention the export extension should be denied because of domestic need for the gas. Our analysis of supply and demand shows emphatically that this is not true.

DOE's conclusion there are more than adequate supplies to meet both domestic and export demand makes it unnecessary to address what strikes us as an underlying effort by the Protestors to assert the section 3 public interest standard to obtain, in effect, a private right of eminent domain to take natural gas from an exporting producer for their own use.

B. Other Public Interest Considerations

Domestic need is the only explicit public interest consideration identified by DOE Delegation Order No. 0204-111. However, as in the *Yukon Pacific Corporation* export authorization, the Department considered the potential effects of the PANGC/Marathon proposal on other aspects of the public interest.[117/] These other considerations include the effects on Alaskan interests, energy production, international relations, and the environment.

1. Alaskan Interests

An extension of PANGC and Marathon's export authority would continue tangible, economic benefits to the Cook Inlet area and the State of Alaska. Based on 1995 data, the Applicants assert their LNG operations accounted for over an estimated $20 million annually in State and local royalty and tax revenues and, either directly or indirectly, over 800 jobs generating over $40 million in personal income per year.[118/] The Applicants maintain the Department's denial of the requested extension would have, consistent with the asserted benefits, numerous adverse effects on the local economy and gas markets. These effects include the closure of the LNG plant and the related loss of jobs and personal income, the elimination of a possible, cost-effective peak

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117/ *See supra* note 2.

118/ *See* Appendix C to Application, *supra* note 36, at 6-5. The $20 million plus in revenues include $1.51 million in property taxes to Kenai Peninsula borough, $17.6 million in production tax and royalty payments to Alaska, and $1.7 million for State income taxes on plant and lease operations. In addition, DOE notes 1995 Federal income taxes associated with the LNG export totaled $23 million.

shaving arrangement at the plant, the shut-in of gas production for which there is no local market and associated job losses, and tax and royalty revenue losses.[119/]

The Protestors dispute these losses, arguing they would be outweighed by losses associated with the economic impacts of a shortage and price increases, including the closure of Unocal's fertilizer plant.[120/] However, this argument presumes the proposed export extension will cause a shortfall, a premise which DOE does not accept. In addition, we are not persuaded by the Protestors' allegations, which the Applicants dispute, that the LNG plant could continue to operate economically as a source of peak supplies, without LNG exports, or that local demand, even if projections were not overstated as the Applicants claim, could absorb all Cook Inlet production by 2005.[121/] Furthermore, the Protestors have not shown reasonable price increases in response to competition would be inconsistent with the public interest. Normal competition for gas supplies in southcentral Alaska, competition to which the LNG exports necessarily contribute, can only encourage additional exploration for that resource. This, in turn, can be expected to lead to increased economic activity beneficial to the State.

2. Energy Production

In *Yukon Pacific*, the Department emphasized the strong public interest in the "efficient production of the Nation's energy resources."[122/] We believe an extension of the Applicants' export

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119/ *Id.*

120/ Unocal's December 22, 1997, Initial Comments at 16; *see also* Attachment D to ENSTAR's December 22, 1997, Comments, *supra* note 25. The ISER(Goldsmith) "doomsday" memorandum on the costs to Cook Inlet consumers of a gas shortage is based on an unanticipated shortfall.

121/ *E.g.*, the Applicants' May 9, 1997, Answer at 99-100.

122/ 1 FE at ¶ 70,259 at 71,137.

will encourage the development of Alaska energy resources and similarly benefit both producers and consumers.

The Protestors claim the Cook Inlet is insensitive to market factors and the current market is not competitive.[123/] They argue DOE's extension of the export, and that factor alone, will determine whether gas shortages occur in southcentral Alaska, irrespective of which party's supply and demand forecasts are adopted, and they seek to preserve existing reserves to meet local demand.[124/]

The Department does not accept the factual accuracy of the Protestors' contentions or the manner in which they frame the issue. We agree with the Applicants the competitiveness of the local market (as well as sufficiency of supply) is evidenced by, among other things, the historically low wellhead prices of Cook Inlet gas compared to those in the lower 48 States (26 percent lower on average in 1996 despite higher average production costs),[125/] and to the cost of competing fuels to Cook Inlet end-users.[126/] As stated by the Applicants:

> Contrary to ENSTAR's assertion [], it is not necessary for the structure of the market to be perfect (perfect knowledge, numerous sellers, numerous purchasers) to obviate the need for [Government] intervention. Rather, it is sufficient to demonstrate that the market performs as competitive forces are in play. ... [T]here are ample energy supplies to support the domestic market. The very low domestic gas prices and emergence of new market players (both supply and demand) are an indication that the energy market structure is sufficiently competitive.

123/ *E.g.*, ENSTAR's December 22, 1997, Comments at 9; *see also* Aurora's April 3, 1997, Motion to Intervene at 17.

124/ *E.g.*, ENSTAR's December 22, 1997, Comments at 3.

125/ The Applicants' December 22, 1997, Initial Comments at 22.

126/ The Applicants' February 5, 1998, Reply at 62-63.

> Clearly the gas market in Southcentral Alaska can be characterized as one of few sellers and few buyers. ... However, the behavioral implications of producers having market power, as suggested by Aurora and ENSTAR would be that producers would act to drive up prices in the local market. There is no evidence that this has occurred. Indeed, burnertip prices in Southcentral Alaska are the lowest in the U.S. PANGC and Marathon have nothing to gain by denying gas to the local market.[127/]

Together with the relatively high reserves to production rate in the Cook Inlet (rates which climbed in the last two reported years), these lower wellhead prices and lack of demand have deterred exploration and development.[128/]

As a general proposition, moreover, we agree with the Applicants the continued export of LNG will promote competition in southcentral Alaska, in turn contributing to the efficient development of Alaska energy resources. The contrary position is counterintuitive and short-sighted. While a denial of the requested extension and the elimination of LNG exports to Japan might release gas to the local market at low prices in the near term, it also would diminish exploration and development incentives for all energy resources, including gas, and thus exacerbate, not mitigate, supply issues. The Protestors are concerned the continued export of LNG will bring about a premature shortage of gas for southcentral Alaska. We believe the opposite is more probable. DOE's approval of the requested extension will not obstruct market

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127/ The Applicants' May 9, 1997, Answer at 97-98 (footnotes omitted).

128/ The Applicants' February 5, 1998, Reply at 62-63. The ratio of reserves to annual production was approximately 14 as of January 1, 1997, compared to a 1996 estimate of 8.5 for the lower 48 States. *See* Zobrist, *supra* note 87, at 5.

signals, with salutary ramifications, not only for Cook Inlet development, but also for the efficient development of North Slope gas and other sources of energy.[129/]

3. International Effects

In considering the international effects of granting long-term export authority in *Yukon Pacific*, the Department reinforced its belief the public interest generally is best served by a free trade policy:

> Such a policy promotes energy interdependence among all nations, rather than energy dependence on a few nations. Competition in world energy markets promotes the efficient development and consumption of energy resources, as well as lower prices, whereas economic distortions can arise from artificial barriers to the free flow of energy resources. Accordingly, the DOE believes that the public interest in free trade generally supports approval of proposed exports.[130/]

Implicitly reaffirming this policy, the President emphasized the global economy in the January 19, 1999, State of the Union address and specifically acknowledged the serious financial crisis now affecting Asia and the need "to tear down barriers, open markets and expand trade."[131/]

We agree with the Applicants LNG exports should continue to reduce the trade deficit that is expected to persist with Japan during the extension period, a reduction estimated by the Applicants at $223 million (of a trade deficit then approaching $60 billion) in 1995.[132/] Principally because we find there are sufficient supplies to meet both local and export demand, we believe

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129/ The Zobrist analysis, as we have noted elsewhere in the Order, underscores the interrelationship of demand and development activities, finding "demand for ANS gas in Cook Inlet is directly related to the estimates of Cook Inlet gas reserves", the former difficult to estimate because of the latter's uncertainty.

130/ 1 FE ¶ 70,259 at 71,138.

131/ *Annual Report to Congress on the State of theUnion*, 145 CONG. REC. S330, S333 (daily ed. January 19, 1999).

132/ The Applicants' May 9, 1997, Answer at 23-24.

there is no basis for the Protestors' argument the balance of payment benefits from Unocal's fertilizer sales outweigh those from LNG exports.[133/] However, even if we were comparing the relative impacts on the balance of trade of the certain suspension of LNG exports with the possible closing of the fertilizer plant and suspension of related exports, Unocal's argument ignores the broader negative effects denying the extension would have on the public interest. Approval of the LNG export extends the intangible benefits of this long and stable trade relationship with Japan which, the Applicants note, strengthens existing ties, "sends a positive message to domestic and foreign investors" in Alaska, and "open[s] the doors for other potential Alaska export projects, most notably the North Slope LNG Project."[134/] Conversely, a denial of the requested extension would send negative signals, not in the best interests of the public, including the parties to this proceeding, by breeding uncertainty about the reliability of the United States as a trading partner.

4. The Environment

DOE has considered environmental concerns associated with the proposed export extension within the framework of NEPA, and determined the agency is not required to perform an analysis of the potential environmental effects of granting the application.

133/ *See* Unocal's April 3, 1997, Motion to Intervene at 15.

134/ The Applicants' May 9, 1997, Answer at 23-24. Japan's "perception" of the security of the Applicants' Kenai LNG export is considered a "critical factor" to the future of the North Slope project, estimated to be 10-14 times the size of the Kenai project, *infra* note 28.

NEPA mandates the preparation of an environmental impact statement (EIS) for proposed major Federal actions "significantly affecting the quality of the human environment."[135/] The Applicants assert approval of the requested export extension, which does not involve an increase in LNG volume, new construction, or other change to their existing export operations, will have no significant and measurable environmental effect and thus does not trigger NEPA.[136/] The agency is not required to prepare an EIS, they argue, if it concludes after a "hard look" at the relevant issues, the action will have an insignificant impact on the environment. Furthermore, the Applicants argue the agency is not required to examine the consequences of a projected natural gas shortfall and related fuel-switching, consequences which the Applicants describe as indirect effects, in the absence of new direct effects or where such projected indirect effects are highly speculative and remote.

Moreover, the Applicants assert NEPA, even if it were applicable, does not require the agency to undertake additional environmental review because the proposed extension "falls squarely" within a categorical exclusion adopted by DOE for "Import/Export Natural Gas, No New Construction":[137/]

135/ 42 U.S.C. § 4332(2)(C). The Department's NEPA decisions are guided by regulations promulgated by the Council on Environmental Quality (CEQ) and by supplemental DOE procedures. CEQ regulations permit an agency to conduct an environmental assessment (EA) to determine whether it must prepare an EIS, and if it is not, to issue a "finding of no significant impact" (FONSI). 40 C.F.R. §§ 1501.4 and 1508.9(a)(1). CEQ regulations also permit agencies to adopt "categorical exclusions" for actions which do not individually or cumulatively have a significant effect on the human environment. Neither an EA nor an EIS is normally required for categorical exclusions. 40 C.F.R. §§ 1507.3 and 1508.4.

136/ Application at 13.

137/ *Answer of Phillips Alaska Natural Gas Corporation and Marathon Oil Company to Comments of Union Oil Company of California and Opposing Motions of ENSTAR Natural Gas Company and Aurora Power Resources, Inc. for Further Procedures,* filed March 9, 1998, at 10-16.

> Approval of new authorization or amendment of existing authorization to import/export natural gas under section 3 of the Natural Gas Act that does not involve new construction and only requires operational changes, such as an increase in natural gas throughput, change in transportation, or change in storage operations.

Categorical Exclusion B5.7, 10 C.F.R. Part 1021, Subpart D, Appendix B. The Applicants emphasize NEPA is satisfied so long as the agency's application of the relevant categorical exclusion is not arbitrary and capricious. They note application of the categorical exclusion is consistent with past DOE practice and there are no "extraordinary circumstances"[138/] for which DOE NEPA regulations require preparation of an environmental assessment (EA) or EIS.

The Protestors argue the export extension falls within the exception to the categorical exclusion for "extraordinary circumstances" and DOE cannot meet its NEPA responsibilities without preparing an EA[139/] or an EIS.[140/] More specifically, ENSTAR and Unocal assert their deliverability studies show production shortfalls beginning as early as 2001 (ENSTAR). ENSTAR and Unocal argue the projected deliverability shortfalls, which they claim will result from an extension of the LNG export, constitute "extraordinary circumstances" thereby removing

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138/ CEQ regulations require agencies adopting categorical exclusions to "provide for extraordinary circumstances in which a normally excluded action may have a significant environmental effect." 40 C.F.R. § 1508.4. DOE procedures, at 10 C.F.R. § 1021.410(b)(2), require the agency to determine:

> There are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal. Extraordinary circumstances are unique situations presented by specific proposals, such as scientific controversy about environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; or unresolved conflicts concerning alternate uses of available resources within the meaning of section 102(2)(E) of NEPA; ....

139/ *Comments of Union Oil Company of California on the Need for Further Procedures*, filed February 20, 1998, at 17; *see* Unocal's April 3, 1997, Motion to Intervene at 17.

140/ *Motion of ENSTAR Natural Gas Company Regarding Further Procedures*, filed February 20, 1998, at 8; *see Motion to Intervene and Protest of ENSTAR Natural Gas Company,* filed April 3, 1997, at 59-60.

the application from the categorical exclusion,[141/] and requiring DOE to assess the environmental impacts resulting "from inevitable widespread switching to dirtier fuels."[142/]

After careful consideration of their arguments, DOE rejects the Protestors' insistence compliance with NEPA demands preparation of an EA or an EIS. Approval of an export or import application not involving new construction does not generally constitute a major Federal action significantly affecting the quality of the human environment. It is for this reason such activity has been categorically excluded from the requirement to perform an EIS. The Department is approving here the simple extension of a long-standing export, not a proposal involving the construction and operation of new LNG or alternative energy facilities. The requested five-year extension to export LNG manufactured at an existing facility, "without need for any new construction, and using the same operational methods"[143/] clearly fits within this excluded category. There is nothing unique about this export and no extraordinary circumstances setting it apart from other categorically excluded exports and imports which would require preparation of an EA or EIS. Contrary to the Protestors' claims, we have determined, based on credible supply and demand forecasts, the Cook Inlet has sufficient gas supplies to meet anticipated local and export demand through the extension period. The fuel-switching which the Protestors argue will result from projected shortfalls is thus not "inevitable." Rather, as the Applicants emphasize, fuel-switching would be an indirect, moreover speculative and remote,

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141/ *Id.*

142/ Unocal's February 20, 1998, Comments at 17.

143/ The Applicants' May 9, 1997, Answer at 122.

impact,[144/] one that would take into account factors other than this gas supply even if southcentral Alaska were faced with a shortfall, and neither "extraordinary" nor "significant" for purposes of NEPA. Furthermore, the Department could not at this time conduct a meaningful environmental review of the indirect impacts identified by the Protestors, involving, as the review would, "spinning out multiple hypothetical development forecasts, with multiple options" for alternative fuel generating facilities.[145/]

The Protestors have presented no evidence which persuades us the requested extension poses identifiable environmental consequences requiring preparation of an EA or an EIS. We do not believe the public interest is served by encumbering the decision-making process with additional and, under these circumstances, unnecessary documentation.

C. Other Matters

The Department's November 6, 1997, procedural order requested the submission of additional information and invited reply comments to further develop the record on issues raised in earlier filings. We denied in the November 6 Order the then pending requests for additional procedures, but indicated we would consider, after submission of initial and reply comments, and upon request, whether further procedures were necessary or appropriate. In motions filed on February 20, 1998, the Protestors renewed requests for certain additional procedures (*see* section II.D. of the Order), but failed to show these procedures were necessary or otherwise appropriate,

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144/ *Id.* at 112-123.

145/ *Northeast Utilities Service Co. v. FERC*, 993 F.2d 937, 959 (1st Cir. 1993) (upholding FERC's decision that neither an EA nor an EIS was required before approving the merger of public utility holding and electric companies); *see* the Applicants' March 9, 1998, Answer, at 13-14.

as required by DOE's administrative regulations in 10 C.F.R. Part 590, and in light of the voluminous record already assembled in this proceeding.

D. Conclusion

After taking into consideration all of the information in the record of this proceeding, we find a five-year extension of the authority of PANGC and Marathon to export LNG to Japan has not been shown to be inconsistent with the public interest. In particular, the record shows there is a sufficient regional supply of natural gas to satisfy local and export demand through the extension period. Furthermore, we believe the extension will continue benefits provided by the export to the Alaskan economy, energy production, and international trade.

ORDER

Pursuant to section 3(a) of the Natural Gas Act, it is ordered that:

A. Phillips Alaska Natural Gas Corporation and Marathon Oil Company are authorized to export liquefied natural gas (LNG) from the State of Alaska to Japan for an additional five years, from April 1, 2004, through March 31, 2009.

B. All other terms and conditions contained in Order 261 and its amendments shall remain in full force and effect.

C. All contracts and other documents underlying the sale of the LNG export authorized herein shall be filed with DOE within 30 days of their execution.

D. All motions or requests for additional procedures in this proceeding, not denied by earlier order, are hereby denied.

Issued in Washington, D.C., on April 2, 1999.

John W. Glynn
Manager, Natural Gas Regulation
Office of Natural Gas and Petroleum
Import and Export Activities
Office of Fossil Energy

APPENDIX A

Natural Gas Reserves and Resources Assessments
Categorization and Terminology

This appendix provides a brief, alphabetical description of natural gas supply categories and terminology, and is intended to assist the reader in understanding the natural gas supply discussion in section IV.A of the Order and the related Table 1 ("Gas Reserves and Resource Assessment of Cook Inlet, Alaska"). Table 1 consolidates for comparison the various resource estimates, categorizing them generally as discovered or undiscovered.

Estimation of the supply of any natural resource is a dynamic process subject to recalculation and revision over time. The process involves estimating the location and magnitude of a resource and the accuracy of any such estimation is necessarily limited by (1) the perception and understanding of the origin and occurrence of the resources, (2) the quality and amount of available data from which to project estimates, and (3) the analytical tools available to form the estimates. The effects and relative importance of these limitations change over time, particularly as knowledge of the resource improves.

Associated Gas. Natural gas that overlies (gas cap) or is dissolved in (solution gas) crude oil in a reservoir.

Conventional (or Traditional) Gas Resources. Gas present in relatively high-porosity and high-permeability rocks.

Discovered Natural Gas Resources. The quantity of natural gas produced historically from existing wells plus that proved by drilling and engineering tests. Discovered gas also includes the gas remaining in known fields that will be recovered through extension and complete development of known pools and reservoirs.

Economically Recoverable Resources. Resources, both discovered and undiscovered, that are economically extractable under a given set of price-to-cost relationships and technological assumptions. The Colorado School of Mines Potential Gas Committee's

(PGC) estimates include assumptions of adequate but reasonable prices and normal improvements in technology as part of its definition of potential gas resources.

Natural Gas Reserves. Estimates of natural gas reserves are the key element in, and generally constitute the bulk of gas resource assessments. Reserves are defined by the Society of Petroleum Engineers/World Petroleum Congress (SPE/WPC) as quantities of petroleum that are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty, which depends primarily on the amount and interpretation of reliable geologic and engineering data available at the time of the estimate. The degree of uncertainty can be reflected with two principle reserve classifications: proved and unproved.

Non-associated Gas. Natural gas not in contact, nor dissolved in, crude oil in a reservoir.

Potential Gas Resources. The gas resources potentially recoverable under assumed technological and/or economic conditions. For the purpose of the supply analysis in this Order and in Table 1, proved gas reserves and cumulative production are not included in this definition. Three categories of potential resources are recognized and reported by the PGC - Probable, Possible, and Speculative. Probable and possible resources are analogous to the unproved probable and possible reserve categories. This terminology is a direct expression of the quantity of geologic and engineering data upon which the estimates are based.

- Probable Resources. Probable resources are those associated with further development of fields that have already been discovered. Probable resources bridge the boundary between discovered and undiscovered resources. They include potential extensions of existing pools and new pool discoveries within existing fields.

- Possible Resources. Possible resources are those postulated to exist in new field discoveries associated with already established trends in producing fields.

- Speculative Resources. Speculative resources are postulated to exist in new field discoveries associated with formations (often deeper formations) not previously proved to be productive in provinces that are productive from other formations or in provinces that have not yet been proved to be productive.

Potential Gas Resources Associated with Existing Fields. This resource category is the most assured of potential gas supplies. (The PGC's probable resource category described above is essentially equivalent to this definition.) A relatively large amount of geologic and engineering information is available to aid in the estimation of these resources. This category consists of both extensions to existing pools (reservoirs) and new pool discoveries within existing fields. Hence, the concept of reserve appreciation is incorporated, whereby an increase in ultimate recovery from known, producing fields is inferred from the historical experience that additions to reserves continue to accrue through post discovery increases in the estimates of the sizes of known fields, even though the fields may be decades old. These increases can be derived from the extension of known reservoirs in known fields or from revisions to estimates of the fraction of gas in place that may ultimately be recovered.

Potential Gas Resources Associated with Undiscovered Fields. These are a less assured supply because they are postulated to exist outside of known fields. They include possible and speculative resource categories, the sum of which nearly equates to undiscovered conventional resources defined by the Minerals Management Service (MMS) and the United States Geological Survey (USGS) of the Department of the Interior.

Proved Reserves. Proved reserves, which can be categorized as developed or undeveloped, are petroleum quantities that, by analyzing geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under current economic conditions, operating methods and government regulations.

- Proved Developed Reserves. Proved developed reserves, including behind pipe reserves, are gas resources expected to be recovered from existing wells. Gas obtained by enhanced recovery techniques are considered developed once the necessary equipment is installed, or when the cost to do so is relatively minor. Developed reserves can be categorized as producing or non-producing.

    - Producing. Producing reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Enhanced recovery reserves are considered producing after the project is in operation.

    - Non-producing. Non-producing reserves include shut-in and behind the pipe reserves. Shut-in reserves are expected to be recovered from open completion intervals that have not begun producing or wells shut in due to market conditions, pipeline connections or mechanical problems. Behind pipe reserves are expected to be recovered from zones in existing wells that require additional completion work or a recompletion prior to production.

- Proved Undeveloped Reserves. Proved undeveloped reserves are gas resources expected to be recovered from new wells on undrilled acreage or from deepening existing wells to a different reservoir. Undeveloped reserves are also expected to be recovered when a significant expenditure is required to recomplete an existing well or install production or transportation facilities for primary or enhanced recovery projects.

Recoverable Natural Gas Resources. The amount of gas that is recoverable as a function of technology and/or economics. The recoverable resources consists of both discovered and undiscovered components.

Technically Recoverable Resources. Resources, both in existing fields and in undiscovered accumulations analogous to those in existing fields, that are producible with current or foreseeable technology. Normally, these resources are assessed without consideration of their economic viability. Also, substantial differences exist among the estimating organizations concerning the likely success and impact of foreseeable technologies.

Unconventional (Nonconventional or Less Conventional) Gas Resources. Gas present in low-permeability (tight) reservoirs with matrix permeabilities generally less than 0.1 md. The gas may be present in sandstones, siltstones, carbonates, coalbeds, or shales. This category is essentially equivalent to the United States Geological Survey's (USGS) continuous-type deposits except that no permeability limitation is specified by the USGS.

Undiscovered Natural Gas Resources. The potential gas supply that could become productive with further exploration and development. It includes (1) gas remaining in undiscovered pools and reservoirs within known fields, (2) gas that may be discovered in new fields and reservoirs within provinces that are presently productive, and (3) gas within as yet unproductive provinces.

Unproved Reserves. Unproved natural gas reserves, which can be classified as probable or possible reserves, are calculated with similar geologic and engineering data to that used when estimating proved reserves. However, technical, contractual, economic or regulatory uncertainties preclude such reserves from being classified as proved. Future economic conditions that are different from current conditions can be assumed when calculating unproved reserves, including economic conditions more likely to induce resource development than those conditions existing at the time the estimate is performed. The probability of these economic conditions occurring, along with possible technology enhancements, is reflected in reserve estimations by appropriate probable and possible designations.

- Unproved Probable Reserves. Based on geologic and engineering data, probable reserves are those unproved reserves that are more likely (than unproved possible reserves) to be recovered. There should be at least a 50 percent probability that the reserves actually recovered will equal or exceed the sum of estimated proved and probable reserves. Situations that deem unproved reserves to be classified as probable are specified in the SPE/WPC definition.

- Unproved Possible Reserves. Also based on geologic and engineering data, possible reserves are unproved reserves that are less likely to be recovered. There should be at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of estimated proved, probable and possible reserves. Situations in which unproved reserves will have the possible classification are specified in the SPE/WPC definition.

APPENDIX B

Natural Gas Reserves and Resources
Cook Inlet Estimates

This appendix describes a variety of reports containing resource estimates which have been prepared by Federal, State, and other organizations, and are relied upon or referred to in the Order.

Alaska Department of Natural Resources (ADNR)

The ADNR annually publishes an estimate of reserves, by field, for the State in a report entitled *Historical and Projected Oil and Gas Consumption*. According to the April 1998 ADNR report, which is prepared by the ADNR's Division of Oil and Gas (DO&G), each of the three State agencies that regulate oil and gas production, DO&G, Alaska Oil and Gas Conservation Commission (AOGCC), and the Department of Revenue (DOR), calculate reserves by different methods for their different requirements. The ADNR report, which limits its estimates to proved reserves only, relies on estimates provided by the DO&G and the AOGCC which are based on geologic and engineering factors.

Reserves of each of the Cook Inlet fields were estimated by whichever method was most appropriate for that particular field. Neither details of the estimates nor the methodology employed are included in the ADNR report. The report acknowledges that Cook Inlet gas estimates took into consideration the Applicants' recent comprehensive analysis of Cook Inlet reserves prepared in support of their LNG export extension authorization.

While the intervenors, particularly ENSTAR, question the independence of the ADNR published estimates, the DO&G indicated that it is its standard practice to compile reserve estimates from several sources - AOGCC, operators, and other working interest owners, as it did for the 1998 report, and determine reserves based on that information. Although independent calculations of reserves for all Cook Inlet fields were not performed, estimates were confirmed and verified using all data available to ADNR, with modifications made as warranted. This process resulted in a proved reserve estimate of 3,066 Bcf for the Cook Inlet as of January 1, 1998.

As noted above, the ADNR report only provides proved reserves estimates. There are no estimates in the report for potential resources. However, in a report dated October 1, 1997, Daniel H. Zobrist of the ADNR (DO&G) considered reserve appreciation for Cook Inlet fields. The Zobrist report estimated that between 100 Bcf and 600 Bcf of reserve growth would be available by 2009.

DOE's Energy Information Administration (EIA)

EIA does not publish reserve information that separates Cook Inlet from the remainder of Alaska. However, Unocal's familiarity with reserves data State-wide allowed it to develop an estimate of what EIA would report for Cook Inlet proved reserves from EIA's State-wide data. This is the value DOE is using for EIA's estimate in this analysis (*see* Table 1). The published Alaska State-wide EIA estimate of non-associated gas was 3,216 Bcf, as of January 1, 1997.[1/] Unocal does not address associated gas in this analysis, although Unocal does include a small volume of associated gas it its own proved reserves estimate. EIA determines this value for non-associated reserves by summing each operator's confidential estimates of proved reserves, which are required to be filed by law. Unocal estimated the EIA values for Cook Inlet non-associated

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1/ Revised in *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1997 Annual Report* (December 1998), DOE/EIA-0216(97), Table 10 at 32.

gas by backing out 36 Bcf of non-associated gas, which Unocal claims were included in the published numbers, from the only three other fields not located in the Cook Inlet area. Unocal used ADNR estimates for determining the 36 Bcf of non-Cook Inlet reserves. Since EIA only provides proved reserve estimates, that is the only value that was estimated by Unocal. Unocal then adjusted proved reserves as of January 1, 1997, for estimated 1997 production, to establish an EIA estimate of 2,966 Bcf as of January 1, 1998.

Potential Gas Committee (PGC)

The PGC consists of 180 members from all segments of the oil and gas industry, Government, and academia. The committee has published biennial estimates of the potential supply of natural gas for the United States since 1964, except 1974. The committee functions independently but with the guidance and assistance of the Potential Gas Agency (PGA) of the Colorado School of Mines. The report utilized by DOE was the *Potential Supply of Natural Gas in the United States* (December 31, 1996), published in March 1997.

The PGC's estimates are of natural gas that, in the judgment of its members, can be recovered by conventional means given adequate economic incentives in terms of price-to-cost relationships and utilization of current or foreseeable technology. No consideration is given to whether or not this resource will be developed; rather, the estimates are of resources that could be developed if the need and economic incentives existed.

The PGC estimates do not include proved reserves. Estimates by the PGC are expressed in terms of three resource categories - probable, possible and speculative. The basic technique for estimation of potential gas resources is to compare the factors that control known occurrences of natural gas with factors present in prospective areas. This attribution technique is applied to each of the categories adopted by the PGC. In each case, what is known about the prospective area is evaluated relative to what is known about natural gas accumulations that have been discovered in other areas of the same geologic province or in similar provinces. Natural gas occurrences are related to conditions favoring their formation and accumulation, such as the existence of source rocks, sufficient maturation of organic material, and the presence of reservoir rocks and traps. Studies of producing areas provide information on the productive capacity of particular formations and the average size of accumulations. Where data permit, trend- or play-analysis techniques are used.

Estimates of the minimum, most likely, and maximum resource potential are reported for each of the three resource categories. For the Cook Inlet area, combined onshore and offshore, the PGC reports that as of December 31, 1996, the most likely probable, possible, and speculative resources are 1,050 Bcf, 2,100 Bcf, and 3,400 Bcf, respectively. To update the estimates to January 1, 1998, DOE assumed no reserve growth took place during 1997. Thus, the probable resources as of January 1, 1998, are 1,050 Bcf.

United States Geological Survey (USGS)

At DOE's request, the USGS prepared an administrative report which considers three categories of natural gas resources as potential future additions to natural gas reserves in the Cook Inlet. (*See* Appendix C, David W. Houseknecht, *Alaska Cook Inlet Natural Gas Resources, Potential Sources of Future Additions to Reserves* (November 4, 1997) USGS.) These categories include (1) future growth of reserves in existing fields, (2) undiscovered resources of conventional natural gas, and (3) coalbed methane. Regarding the first two categories, future reserve growth and undiscovered resources, the administrative report summarized estimates made by the USGS in published reports, in particular the agency's 1995 *National Assessment of Oil and Gas Resources of the United States*. The report's projection regarding coalbed methane was based on USGS expertise but did not make any volumetric projections.

Using production data, as well as statistical projections of operator reported field level reserve estimates contained in the proprietary EIA Oil and Gas Integrated Field File as a basis, the USGS determined the estimated total reserve growth during the time interval 1994-2015 is 1,858 Bcf (468 Bcf of associated gas and 1,390 Bcf of non-associated gas).[2/] To facilitate the use of the reserve growth estimates in this Order, the USGS subsequently adjusted the time interval of total reserve growth to 1994-2009. Using the identical methodology employed in determining reserve growth to 2015, the USGS determined the estimated total reserve growth is 1,369 Bcf (353 Bcf of associated gas and 1,016 Bcf of non-associated gas) for this shorter time interval. An analysis of the EIA data indicates that the EIA has booked 331 Bcf of non-associated gas as proved reserves during the years 1994-1996 which was previously categorized as reserve growth by the USGS.[3/] DOE assumed none of the estimated reserve growth was booked as proved reserves for 1997. Thus, assuming the 331 Bcf of the non-associated gas reserve growth has already taken place, the adjusted reserve growth from 1998 through 2009 is 1,038 Bcf (353 Bcf of associated gas and 685 Bcf of non-associated gas) (Table 1, Column I).[4/]

2/ *See* Unocal's February 5, 1998, Comments at 18, and Appendix C to the Order at 2.

3/ *Id.*

4/ The 1,038 Bcf does not reflect the upward revision associated with EIA's adjustment to proved reserves, *see supra* note 1.

Estimates of undiscovered resources of conventional natural gas are made at the hydrocarbon play level. The technically recoverable mean volume of these resources, which result from new field discoveries associated with established trends, is estimated to be 1,385 Bcf. For the Cook Inlet play containing non-associated gas, the estimated mean volume of technically recoverable natural gas is 738 Bcf. For the Cook Inlet play containing associated gas, the estimated mean value of technically recoverable natural gas is 647 Bcf.

The volumes of natural gas that may be economically recoverable from the Cook Inlet are price sensitive and thus reported under different gas price scenarios. The basis for the estimates of recoverable undiscovered hydrocarbons as a function of price is that exploration, development, and production efforts will not take place unless the revenues expected to be received from the eventual production will cover costs, including a normal return on investment. For the combined onshore and offshore State waters in the Cook Inlet area, the USGS estimates that at $18 per barrel for oil or $2 per Mcf for gas, 321 million barrels of oil or 48 percent of the oil, 321 Bcf or 48 percent of the associated gas, and 120 Bcf or 13 percent of the non-associated gas can be produced economically. Thus at $2.00 per Mcf, the USGS estimates that 441 Bcf of gas will be economically recoverable from new field discoveries. At $30 per barrel for oil or $3.34 per Mcf for gas, the highest cost utilized by the USGS analysis, 496 million barrels of oil or 74 percent of the oil, 496 Bcf or 74 percent of the associated gas, and 283 Bcf or 31 percent of the non-associated gas can be produced economically.

A specific assessment of Cook Inlet coalbed methane resources has not been conducted by the USGS. Although the results of other studies suggest there is significant coalbed methane potential in the Cook Inlet Basin, a reasonable estimate of economically recoverable volumes has not been made because of insufficient information. Nevertheless, the USGS asserts that coalbed methane is a resource that could add at least a few hundred Bcf to the reserve base under favorable economic conditions.

Minerals Management Service (MMS)

MMS published their January 1, 1995, resource estimate in *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034. Their mean value for conventionally recoverable undiscovered gas resources for offshore Cook Inlet is 900 Bcf, utilizing a modified probabilistic play analysis model, known as "GRASP", the Geological Resource Assessment Program. This model uses both publicly available and proprietary data. However, none of the MMS resources are considered to be economically recoverable during the LNG export authorization extension period. Offshore reserves were not included in the USGS estimates. Therefore, the MMS estimated reserves are in addition to those calculated by USGS.

TABLE B-1
Proved Gas Reserve Assessments of Cook Inlet, Alaska
Effective January 1, 1996
Billions of Cubic Feet (BCF)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Phillips/Marathon (GeoQuest)					*Alaska Department of Natural Resources*					*ENSTAR (Malkewicz Hueni Associates)* [3]				
		Proved Undeveloped					Proved Undeveloped					Proved Undeveloped			
Field Name	Proved Developed	Behind Pipe	Compression Incremental	Total Proved Undeveloped	Total Proved	Proved Developed	Behind Pipe	Compression Incremental	Total Proved Undeveloped	Total Proved	Proved Developed	Behind Pipe	Compression Incremental	Total Proved Undeveloped	Total Proved
Beaver Creek	20.0	133.4	0.0	133.4	153.4	122.0	0.0	0.0	0.0	122.0	20.0	133.4	0.0	133.4	153.4
Beluga River	625.0	0.0	165.0	165.0	790.0	488.0	0.0	0.0	0.0	488.0	574.0	0.0	0.0	0.0	574.0
Birch Hill [2]	0.0	11.0	0.0	11.0	11.0	0.0	11.0	0.0	11.0	11.0	0.0	11.0	0.0	11.0	11.0
Cannery Loop	34.5	0.0	6.7	6.7	41.2	50.0	0.0	0.0	0.0	50.0	34.5	6.7	0.0	6.7	41.2
Falls Creek [2]	0.0	13.0	0.0	13.0	13.0	0.0	13.0	0.0	13.0	13.0	0.0	13.0	0.0	13.0	13.0
Granite Point [2]	29.0	0.0	0.0	0.0	29.0	29.0	0.0	0.0	0.0	29.0	29.0	0.0	0.0	0.0	29.0
Ivan River [1]	84.2	0.0	0.0	0.0	84.2	75.0	0.0	0.0	0.0	75.0	84.2	0.0	0.0	0.0	84.2
Kenai	144.5	90.1	143.6	233.7	378.2	174.0	0.0	0.0	0.0	174.0	144.5	30.0	0.0	30.0	174.5
McArthur River	591.0	64.7	0.0	64.7	655.7	600.0	0.0	0.0	0.0	600.0	591.0	64.7	0.0	64.7	655.7
Middle Ground Shoal [2]	14.0	0.0	0.0	0.0	14.0	15.0	0.0	0.0	0.0	15.0	14.0	0.0	0.0	0.0	14.0
Nicolai Creek [2]	0.0	2.0	0.0	2.0	2.0	0.0	2.0	0.0	2.0	2.0	0.0	2.0	0.0	2.0	2.0
North Cook Inlet Unit	1,049.0	0.0	115.0	115.0	1,164.0	1,000.0	0.0	0.0	0.0	1,000.0	552.0	0.0	0.0	0.0	552.0
North Fork [2]	0.0	12.0	0.0	12.0	12.0	0.0	12.0	0.0	12.0	12.0	0.0	12.0	0.0	12.0	12.0
North Trading Bay [2]	20.0	0.0	0.0	0.0	20.0	20.0	0.0	0.0	0.0	20.0	20.0	0.0	0.0	0.0	20.0
Sterling [2]	23.0	0.0	0.0	0.0	23.0	23.0	0.0	0.0	0.0	23.0	23.0	0.0	0.0	0.0	23.0
Sunfish	0.0	32.4	0.0	32.4	32.4	0.0	0.0	0.0	0.0	0.0	0.0	32.4	0.0	32.4	32.4
Swanson River Gas	22.0	50.0	0.0	50.0	72.0	155.0	0.0	0.0	0.0	155.0	22.0	50.0	0.0	50.0	72.0
Swanson River Hemlock	240.0	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	240.0	0.0	0.0	0.0	240.0
Trading Bay [2]	28.0	0.0	0.0	0.0	28.0	29.0	0.0	0.0	0.0	29.0	28.0	0.0	0.0	0.0	28.0
West Foreland [2]	0.0	20.0	0.0	20.0	20.0	0.0	20.0	0.0	20.0	20.0	0.0	20.0	0.0	20.0	20.0
West Fork [2]	3.0	0.0	0.0	0.0	3.0	3.0	0.0	0.0	0.0	3.0	3.0	0.0	0.0	0.0	3.0
West McArthur River [2]	1.0	0.0	0.0	0.0	1.0	1.0	0.0	0.0	0.0	1.0	1.0	0.0	0.0	0.0	1.0
Total	**2,928.2**	**428.6**	**430.3**	**858.9**	**3,787.1**	**2,784.0**	**58.0**	**0.0**	**58.0**	**2,842.0**	**2,380.2**	**375.2**	**0.0**	**375.2**	**2,755.4**

1 Ivan River includes: Ivan River, Lewis River, Pretty Creek, and Stump Lake fields.
2 For GeoQuest and Malkewicz Hueni Associates (MHA), this denotes Alaska Oil and Gas Conservation Commission (AOGCC) - assigned gas reserves.
3 MHA's work relied entirely upon publicly available data and has been confined to the four fields that account for the majority of reserves: North Cook Inlet, Beluga River, McArthur River, and Kenai. MHA accepted GeoQuest's reserve estimates for the fields in which MHA has not completed analysis work.

TABLE B-2
Proved Gas Reserve Assessments of Cook Inlet, Alaska
Effective January 1, 1998
Billions of Cubic Feet (BCF)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
			Phillips/Marathon (GeoQuest)			*ADNR [4]*			*EIA,*	*Unocal [5]*			*ENSTAR (Malkewicz Hueni Assoc.) [6]*		
	ADNR [3]	ADNR [3]	(1996 est.- '96 -'97 production)						as reported by Unocal	1/1/98 Estimated Proved Reserves			1/1/98 Estimated Proved Reserves		
Field Name	**1996 Production**	**1997 Production**	**Proved Developed**	**Total Proved Undeveloped**	**Total Proved**	**Proved Developed**	**Total Proved Undeveloped**	**1/1/98 Total Proved**	**Total Proved**	**Proved Developed**	**Proved Undeveloped**	**Total Proved**	**Proved Developed**	**Proved Undeveloped**	**Total Proved**
Beaver Creek	3.0	4.6	12.4	133.4	145.8	104.0		104.0		21.0	42.0	63.0	32.0	0.0	**32.0**
Beluga River	36.9	35.0	553.1	165.0	718.1	669.0		669.0		552.0	81.0	633.0	500.7	0.0	**500.7**
Birch Hill	0.0	0.0	0.0	11.0	11.0		11.0	11.0		0.0	0.0	0.0	0.0	11.0	**11.0**
Cannery Loop	2.1	3.1	29.3	6.7	36.0		33.0	33.0		32.0	24.0	56.0	18.2	6.7	**24.9**
Falls Creek	0.0	0.0	0.0	13.0	13.0		13.0	13.0		0.0	0.0	0.0	0.0	13.0	**13.0**
Granite Point	2.3	2.6	24.2	0.0	24.2	24.0		24.0		8.0	0.0	8.0	43.7	0.0	**43.7**
Ivan River [1]	7.2	5.9	71.1	0.0	71.1	48.0		48.0		22.0	28.0	50.0	48.1	0.0	**48.1**
Kenai	13.3	12.7	118.5	233.7	352.2	283.0		283.0		242.0	30.0	272.0	102.2	76.1	**178.3**
McArthur River	67.3	66.8	456.9	64.7	521.6	525.0		525.0		343.0	221.0	564.0	529.3	64.7	**594.0**
Middle Ground Shoal	0.9	1.1	12.1	0.0	12.1	13.0		13.0		1.0	18.0	19.0	13.8	0.0	**13.8**
Nicolai Creek	0.0	0.0	0.0	2.0	2.0	2.0		2.0		0.0	0.0	0.0	0.0	0.0	**0.0**
North Cook Inlet Unit	56.0	52.5	940.6	115.0	1,055.6	1,023.0		1,023.0		922.0	0.0	922.0	617.8	0.0	**617.8**
North Fork	0.0	0.0	0.0	12.0	12.0		12.0	12.0		0.0	0.0	0.0	0.0	12.0	**12.0**
North Trading Bay	0.0	0.5	19.5	0.0	19.5	20.0		20.0		5.0	15.0	20.0	0.0	0.0	**0.0**
Sterling	0.0	0.0	23.0	0.0	23.0	23.0		23.0		0.0	0.0	0.0	0.2	0.0	**0.2**
Sunfish	0.0	0.0	0.0	32.4	32.4			0.0		0.0	0.0	0.0	0.0	32.4	**32.0**
Swanson River [2]	33.3	28.7	199.9	50.0	250.5	182.0		182.0		125.0	69.0	194.0	186.4	50.0	**236.4**
Trading Bay	0.4	1.1	26.5	0.0	26.5	28.0		28.0		0.0	0.0	0.0	57.7	0.0	**57.7**
Tyanok Deep	0.0	0.0					30.0	30.0							
West Foreland	0.0	0.0	0.0	20.0	20.0		20.0	20.0		0.0	0.0	0.0	0.0	20.0	**20.0**
West Fork	0.0	0.0	3.0	0.0	3.0	3.0		3.0		3.0	0.0	3.0	0.0	0.0	**0.0**
West McArthur River	0.3	0.2	0.5	0.0	0.5					0.0	0.0	0.0	0.1	0.0	**0.1**
Total	**223.0**	**214.7**	**2,490.5**	**858.9**	**3,349.4**	**2,947.0**	**119.0**	**3,066.0**	**2,966.0**	**2,276.0**	**528.0**	**2,804.0**	**2,150.2**	**285.9**	**2,436.1**

1 Ivan River includes: Ivan River, Lewis River, Pretty Creek, and Stump Lake fields.
2 Swanson River includes Swanson river Gas and Swanson River Hemlock
3 Reported in ADNR report: "Historical and Projected Oil and Gas Consumption," April 1998, Table 4.
4 Estimated as of January 1, 1998, by the ADNR in: "Historical and Projected Oil and Gas Consumption," April 1998, Table 1.
5 Unocal's Initial Comments, 12/22/97, Exhibit A1, page 15 & Table 3.
6 From "Analysis of Cook Inlet Alaska Gas Reserves and Deliverability", 12/19/97.

APPENDIX C

Alaska Cook Inlet Natural Gas Resources, Potential Sources of Future Additions to Reserves

Administrative Report

David W. Houseknecht
U.S. Geological Survey

November 4, 1997

This report summarizes the potential for future additions to natural gas reserves in the Cook Inlet of Alaska. It has been prepared at the request of the Department of Energy (DOE) as background for a pending decision on an application filed with the Office of Fossil Energy of DOE for a five year extension of an authorization to export liquefied natural gas from Alaska.

Three categories of natural gas resources are considered, including (1) future growth of reserves in existing fields, (2) undiscovered resources of conventional natural gas, and (3) coalbed methane. The following summary incorporates the most recent information available to the U.S. Geological Survey (USGS). More specific information regarding each category of natural gas resources can be found in the publications cited at the end of the report.

Reserve Growth

As part of the USGS 1995 National Assessment of Oil and Gas Resources of the United States, estimates were made of reserve growth in existing fields. These estimates were made on the basis of statistical projections of series of data contained in the proprietary EIA Oil and Gas Integrated Field File (OGIFF). The OGIFF contains field-level reserve estimates reported annually to EIA by field operators. When the sum of cumulative production plus reported reserves is plotted over the interval of time represented by the OGIFF (1977 to present), a growth trend is present in most petroleum provinces of the Nation .

The 1995 USGS statistical projection of reserve growth was based on OGIFF data through 1992 and yielded the following results for natural gas in the Cook Inlet. These estimates assume the economic viability of additions to reserves in existing fields.

Reserve Growth During the Time Interval:	1994-2015	1994-2080
Associated Gas (Bcf):	468	1,135
Non-Associated Gas (Bcf):	1,390	3,207
Total Natural Gas (Bcf):	1,858	4,342

Based on this analysis and considering that part of the 1994-2015 reserve growth estimate has already taken place, it is reasonable to assume that **more than 1,000 billion cubic feet (Bcf) of gas will be added to reserves of existing fields in the Cook Inlet before 2015.**

Undiscovered Conventional Resources

As part of the USGS 1995 National Assessment of Oil and Gas Resources of the United States, estimates were made of undiscovered oil and gas resources at the hydrocarbon play level in each petroleum province of the Nation. For the Cook Inlet, one play containing non-associated gas potential and one containing associated gas potential were assessed. Estimates of *technically recoverable* natural gas in each play are summarized below.

Probability that play contains more than amount of gas indicated:	F95	F50	F05	Mean	s.d.
Play 0303 Beluga-Sterling Gas Play (non-associated gas, Bcf)	42	432	1,923	738	649
Play 0304 Hemlock-Tyonek Oil Play (associated gas, Bcf)	43	446	1,337	647	423

Although estimates of *technically recoverable* resources are useful indicators of the petroleum potential of a petroleum province, they must be recast into estimates of *economically recoverable* resources for purposes of forecasting how much natural gas may be added to reserves in the foreseeable future. The USGS in 1997 released estimates of economically recoverable oil and gas based on the mean estimate of technically recoverable resources reported in the 1995 National Assessment.

Estimates of economically recoverable gas resources for the Cook Inlet were calculated and reported under the category of the "southern Alaska province." Results are reported for two incremental cost scenarios. **The USGS estimates that 441 Bcf gas would be economically recoverable at a cost of $2.00 per thousand cubic feet (mcf), and that 779 Bcf gas would be economically recoverable at a cost of $3.34 per mcf.** These estimates include both non-associated and associated gas from the two plays mentioned above.

Naturally, these estimates represent volumes of natural gas that may be economically recoverable based on USGS mean estimates of undiscovered resources, and do not take into consideration the presence or absence of incentives for operators to explore for, or develop, natural gas resources that may be present in the Cook Inlet.

Coalbed Methane

Although the USGS has not conducted a specific assessment of coalbed methane resources of the Cook Inlet, evidence suggests that large volumes may be present. This evidence includes:

(1) Existing production and potential undiscovered resources of conventional, non-associated gas within the Beluga-Sterling gas play are thought to have been sourced mostly from coalbeds and coaly organic material dispersed in associated strata. The presence of these conventional natural gas resource, therefore, indicate good potential for gas to occur within the coalbeds themselves.

(2) Based on information from numerous oil and gas exploration and development wells and from studies of outcrops along the margins of the Cook Inlet basin, the sedimentary strata of the Cook Met are known to contain a large number of coalbeds that are of sufficient thickness to provide adequate reservoirs of coalbed methane.

(3) A recent study of coalbed methane potential conducted by the Alaska Division of Oil and Gas included the drilling in 1994 of a borehole to measure and sample coalbeds and associated strata. Desorption tests conducted on samples from that borehole indicate the coals contain substantial amounts of methane. The results of this study suggest significant coalbed methane potential in the Cook Inlet basin, although no estimates of total recoverable or economically recoverable coalbed methane resources were made.

Although the information cited above suggests there may be significant coalbed methane potential in the Cook Inlet basin, no analysis has been conducted regarding the economic viability of this resource. Therefore, it remains a largely unknown commodity at this time. We have learned recently that one natural gas producer plans to drill five coalbed methane evaluation wells this year in the Cook Inlet, and will embark on an ambitious development program if results are positive. This suggests that coalbed methane may start to contribute to Cook Inlet gas production in the near future.

Summary

Future additions to Cook Inlet natural gas reserves may come from three sources: (1) growth of reserves in existing fields, (2) undiscovered conventional resources, and (3) coalbed methane.

(1) Reserve growth is the most certain of these additions to reserves, and likely will result in the addition of more than 1,000 Bcf before 2015.

(2) The discovery of undiscovered, conventional natural gas resources is less certain and is dependent on economic conditions viewed by industry as favorable for Cook Inlet gas exploration. The USGS estimates that between 400 and 800 Bcf gas could be added to reserves through discovery of new fields at assumed costs between $2.00 and $3.34 per mcf.

(3) The presence of coalbed methane resources is confirmed, although insufficient information exists to make reasonable estimates of economically recoverable volumes. At this time, coalbed methane can be viewed as a resource that could add at least a few hundred Bcf to reserves if economic conditions are favorable for the private sector to make a commitment to exploration and development.

Although estimates of potential natural gas that may be added to Cook Inlet natural gas reserves vary among the three categories of resources summarized above, it is likely that at least one trillion cubic feet of gas will be added before 2015 and it is possible for that number to double if economic conditions stimulate industry activity.

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APPENDIX D

Natural Gas Deliverability Forecasts

This appendix describes the deliverability analyses submitted by the parties as well as an independent forecast by the Alaska Department of Natural Resources (ADNR). These analyses forecast Cook Inlet natural gas production for periods generally coinciding with the 2004-2009 export extension period.

The Applicants

Schlumberger GeoQuest Reservoir Technologies (GeoQuest) performed the underlying analysis for the Applicants' initial deliverability forecasts.[1/] This analysis, criticized by the Protestors as lacking sufficient detail to permit an assessment of its validity, was later expanded by Sproule Associates Inc. (Sproule).[2/] The Sproule analysis retained the GeoQuest proved reserve estimate (3,349 Bcf on January 1, 1998), and the addition after 2005 of the Potential Gas Committee's (PGC) estimate of "probable resources" (volumes corresponding to the minimum (600 Bcf) and most likely (1,050 Bcf)).[3/] No reserve growth was explicitly assumed in either the original GeoQuest work or the Sproule analysis but both adopt "probable" resource numbers corresponding to reserve growth.

The Sproule analysis used a forecast methodology described as an integration of material balance and decline curve techniques. For the four largest Cook Inlet fields (North Cook Inlet Unit, Beluga River, Kenai, and McArthur River), maximum gas flow rates (well capacities) were

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1/ Exhibit L to the Applicants' December 22, 1997, Comments.

2/ *See Clarifications to PANGC and Marathon's Deliverability Forecast, Cook Inlet, Alaska* (April 8, 1998), filed by the Applicants on April 15, 1998.

3/ Potential Gas Committee, *Potential Supply of Natural Gas in the United States* (March 1997), Table 55 at 104-105. The report's estimates were current as of December 31, 1996.

calculated for each well and aggregated for each field. As long as projected well capacities exceeded actual average (1996, 1997) production rates, production forecasts were maintained at essentially current levels. When projected well capacities fell below historic production levels, a hyperbolic decline rate was assumed. For the remaining fields, the maximum capacity was assumed to equal recent production rates. It was also assumed compression would be added "as needed."

When production capacity above that available from proved reserves was needed to meet assumed demand levels, the Sproule analysis triggered production of probable resources. For the Resource Decisions and Northern Economics (Resource Decisions) "Expected" demand case, the PGC "Most Likely" estimate of 1,050 Bcf was assumed between the years 2007 and 2019 based on the discovery of 14 fields of 75 Bcf each. The estimated year of first deliverability shortfall for this case is 2019. The same approach was used for the Resource Decisions "High" demand case, except the assumed availability of probable resources was limited to the 600 Bcf corresponding to the PGC "Minimum" resource case for the Cook Inlet. These resources were represented by eight new discoveries of 75 Bcf each, brought into production between 2006 and 2009. The estimated year of first shortfall for this case is 2013.

The Protestors claimed the Sproule analysis overstated the projected availability of Cook Inlet reserves.[4/] Using the Sproule production capacity versus time relationship and the Resource Decisions (the Applicants) high demand case, Union Oil Company of California (Unocal) estimated eleven of the 75 Bcf discoveries must be brought on-line in a six-year period beginning

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4/ *See, e.g.*, *Comments of Union Oil Company of California on Applicants' "Clarifications" to Deliverability Analysis*, filed May 15, 1998, at 9.

in 2004 to avoid a shortfall before 2009.[5/] Unocal argued this is an unreasonable expectation based upon recent success rates in exploratory drilling.

ENSTAR

Malkewicz Hueni Associates (MHA) prepared two gas deliverability forecasts for ENSTAR Natural Gas Company (ENSTAR), one limited to proved reserves and the other for total gas resources, which include unrisked, unproved reserves.[6/] The unrisked, unproved reserves set out in Table 1 incorporate 351.8 Bcf of probable reserves from the MHA reserves report and 216 Bcf of possible reserves (120 Bcf of dry gas and 96 Bcf of associated gas) from new oil field discoveries reported by the James E. Eason assessment (Eason).[7/]

MHA used three techniques to forecast production of the Cook Inlet fields. The first is the well potential technique which GeoQuest also employed to calculate the maximum flow potential of a well from flow rate and backpressure measurements. The second MHA methodology used a decline curve analysis to forecast production of 22 fields, including the Kenai Field, that have been in production decline for a time sufficiently long to allow application of the methodology. In addition to these fields, two small fields, the Falls Creek Field and the North Fork Field, which are not yet producing but had reserves assigned by GeoQuest, were included in this section of the analysis. The third methodology applied to those fields which are not yet declining in production, including the McArthur River Field, the Swanson River Field Hemlock Formation, and a group of six fields for which GeoQuest assigned reserves but MHA did no

5/ *Id*. at 12.

6/ Attachment C to ENSTAR's December 22, 1997, Comments.

7/ Attachment B to ENSTAR's December 22, 1997, Comments. The Eason assessment was commissioned by ENSTAR to identify the magnitude and timing of possible new oil and gas fields in the Cook Inlet area.

technical review. The deliverability of these reserves was scheduled by assuming these fields would continue "plateau" production for an assumed period of time before starting to decline.

Results

Scenario 1: Proved reserves with base case demand: the first annual deliverability shortfall occurs in 2001. By 2009, the annual deliverability shortfall reaches 131 Bcf and the total cumulative shortfall reaches 473 Bcf.

Scenario 2: Proved, plus unrisked probable and possible reserves with base case demand: the first annual deliverability shortfall occurs in 2004. By 2009, the deliverability shortfall reaches 93 Bcf and the total cumulative shortfall reaches 236 Bcf.

According to the Applicants, the MHA deliverability forecast understated the production capacity of Cook Inlet, primarily, the Applicants claimed, because MHA relied on an inaccurate reserve base.[8/] In addition, the Applicants stated MHA used the actual field delivery rate, limited by customer take rates, instead of the higher, potential flow rates, to forecast the deliverability of the Kenai field, and erroneously assumed daily production rates for the McArthur River Field that are lower than the field data indicate. The Applicants believe these errors also contributed to projections lower than actual productive capacity.

Unocal

The Unocal deliverability model is based on a comprehensive system analysis and consists of three basic components: a demand module, a supply module, and a supply/demand

8/ *See* the Applicants' February 5, 1998, Reply Comments.

interface.[9/] The model reports any daily or annual deliverability shortfalls through the first quarter of 2009.

Unocal's demand module relied on estimates for the Cook Inlet region prepared for ENSTAR by the Institute of Social and Economic Research, University of Alaska.[10/] The supply module analysis calculated the relationship between the maximum gas production capacity of each field, using the same backpressure equation as in the previous two deliverability analyses, and cumulative production.[11/]

Two methods were used to forecast future field production capacity: decline curve analysis and full system analysis. Decline curve analysis consists of extrapolating the observed field production decline trends into the future. This approach was used by Unocal for half of the Cook Inlet fields. Full system analysis is based upon a model that includes estimates of the effects of gas flow rates on all components of the delivery system, beginning with reservoir pressure and ending at the point of delivery. This approach was used in the remaining half of the cases.[12/]

The production capacity calculated from Unocal's model was based on estimated January 1, 1998, reserve levels (*see* Table 1) for two specified scenarios: (1) proved and unproved reserves, and (2) proved, unproved, and new resources. The model calculated production rates at the beginning of each year, by determining the cumulative production for each field since January 1, 1998, and then, after deducting field requirements, calculating the gas flow rate at which that

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9/ *See* Unocal's December 22, 1997, Initial Comments.

10/ *See* ENSTAR's April 3, 1997, Motion to Intervene, Exhibit 7. Total demand for the period from 1997 to 2009 declined from 2,853 Bcf in ENSTAR's April 1997 estimate, *infra*, to 2,719 Bcf in its December 1997 comments.

11/ The details of this process are contained in Appendix 2 to Unocal's December 22, 1997, Initial Comments.

12/ *Id.*

field can produce its next year's unit of gas. That rate was assumed to be the daily production rate for the next year. Unocal assumed capital projects, such as compression, are implemented as necessary to maintain gas flow rates.

Once demand and production capacity were determined, the deliverability model matched demand with supply. For each day beginning January 1, 1998, priority contract demand was satisfied before any released excess was used to meet any uncontracted demand. The model progressed through each day until December 31, 1998. Once the 1998 run was completed, the cumulative production volumes were updated, a new maximum production rate was calculated for 1999, and the deliverability model advanced to the next annual run. This process is repeated until the model has calculated deliverability for every year until 2017.

Unocal's model showed daily and annual deliverability shortfalls. A daily deliverability shortfall occurs when demand grows faster or declines slower than productive capacity. However, because average annual demand is less than average daily productive capacity, storage can be used to eliminate peak shortfalls. Annual shortfalls occur when the annual average daily production is less than annual average daily demand.

The model produced results for six scenarios, summarized below:

Scenario 1: Proved and unproved reserves with low demand - the first annual shortfall occurs in 2007, reaching an annual-equivalent shortfall of 101 Bcf during the first quarter of 2009.

Scenario 2: Proved and unproved reserves with base demand - the first annual shortfall occurs in 2006, with an annual-equivalent shortfall of 128 Bcf during the first quarter of 2009.

Scenario 3: Proved and unproved reserves with high demand - the first annual shortfall occurs in 2004, with an annual-equivalent shortfall of 209 Bcf during the first quarter of 2009.

Scenario 4: Proved, unproved, and new resources with low demand - the first annual shortfall occurs in 2008, with an annual-equivalent shortfall of 83 Bcf during the first quarter of 2009.

Scenario 5: Proved, unproved, and new resources with base demand - the first annual shortfall occurs in 2007, with an annual-equivalent shortfall of 114 Bcf during the first quarter of 2009.

Scenario 6: Proved, unproved, and new resources with high demand - the first annual shortfall occurs in 2004, with an annual-equivalent shortfall of 198 Bcf during the first quarter of 2009.

The Applicants asserted the Unocal model predicts an early deliverability shortfall because, like the MHA model, the underlying reserve numbers are too low.

ADNR

Daniel Zobrist, a petroleum economist with ADNR, produced an independent estimate of Cook Inlet gas deliverability in the context of a October 1, 1997, report entitled *The Potential In-State Demand for Alaska North Slope Gas.* The Zobrist analysis assumes each field will maintain 1996 production rates until depletion reaches 70 percent. Production is reduced by five percent per year thereafter. Production rates for several small fields are increased above 1996 rates reflecting workover plans which would be expected to result in improved production.

Two reserve scenarios were considered: a low-level case which assumed 58 Bcf of additional gas will be found and produced by 2009 (beginning in 2004) and an additional 252 Bcf by 2022; and a high-level case which assumed the increase will be 281 Bcf by 2009 with an additional 570 Bcf by 2019.

The Zobrist analysis did not detail its depletion and reserve growth rates, but the total volume of gas in the proved category appear to be consistent with the estimate in the 1998 ADNR report and, furthermore, reserve growth assumptions, although not unrealistic, appear to be on the low side compared to estimates of the United States Geological Survey.