

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2336 SCOMM 96: HOUSE SPEC. COMM. ON OIL & GAS, 1995-1996

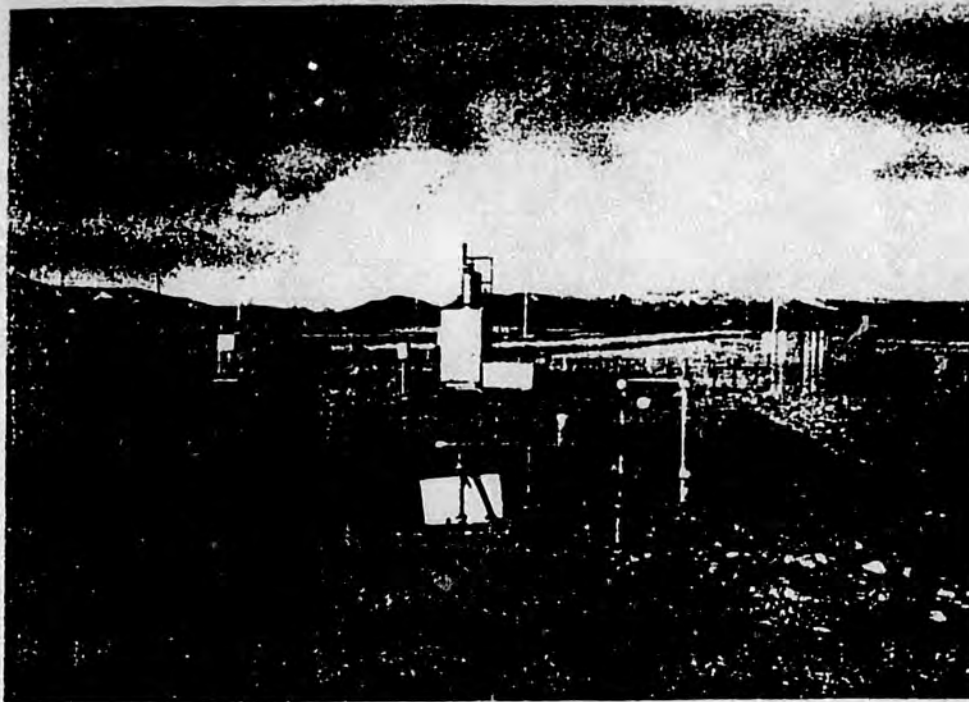


PHOTO #4

-At Left: Solar powered communications to report status.
 -At Center: Water/Gas separator with filters.
 -At Right: Metering system with separate communications system.
 -Well head in the foreground.
 Near Farmington, New Mexico



PHOTO #5

Coal Bed Methane well head.
 Near Farmington, New Mexico

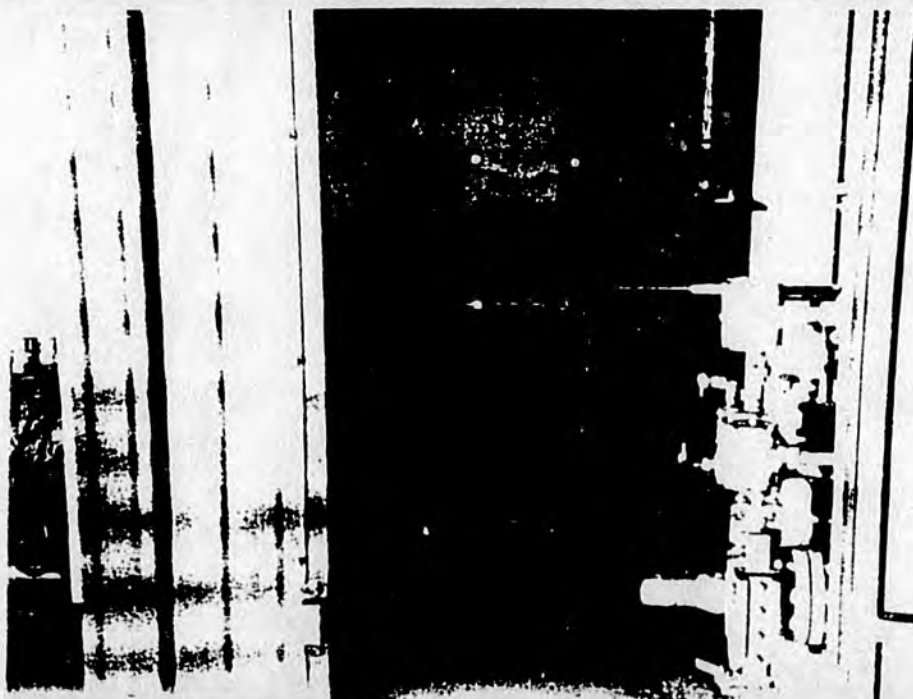


PHOTO #6

Meter Skid; Note the chart in the upper-center of photo, important for well operations.
 All equipment is gas or solar powered.
 Near Farmington, New Mexico

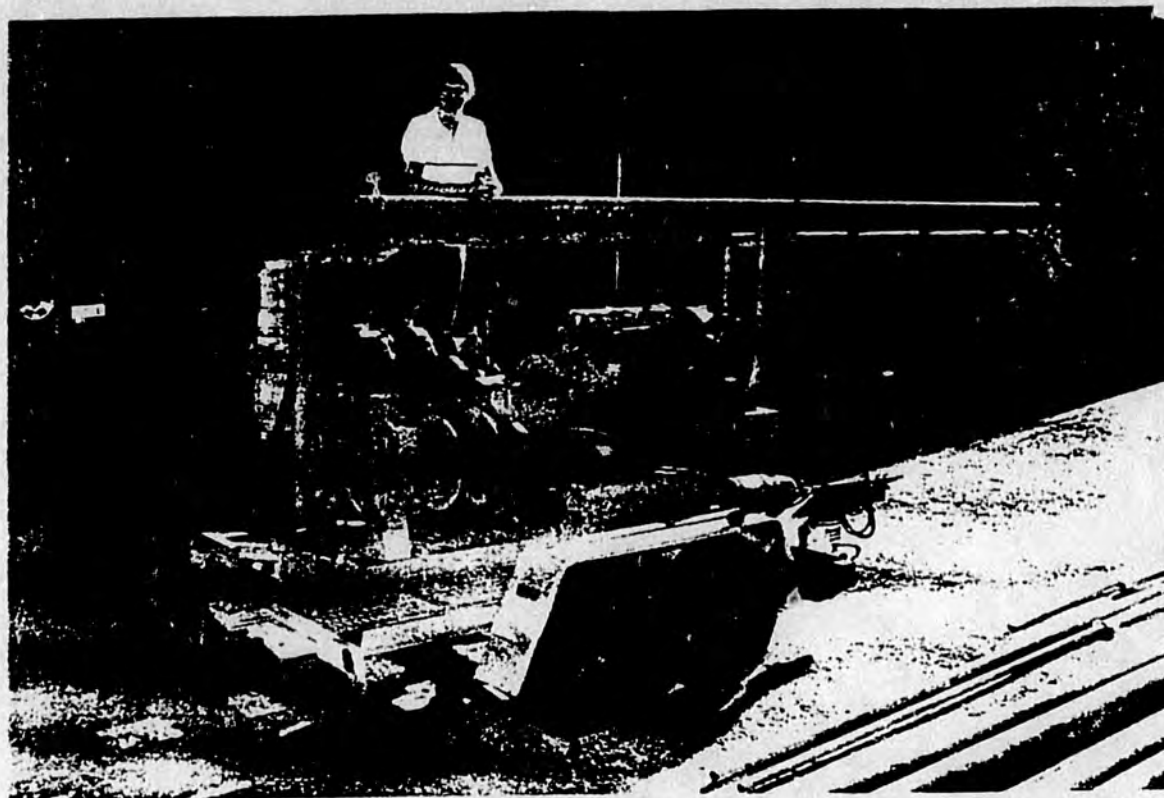


PHOTO #12

*Lapp Resources' portable drill rig, used for exploratory drilling for coal bed methane.
courtesy, Lapp Resources, Inc., 1995*

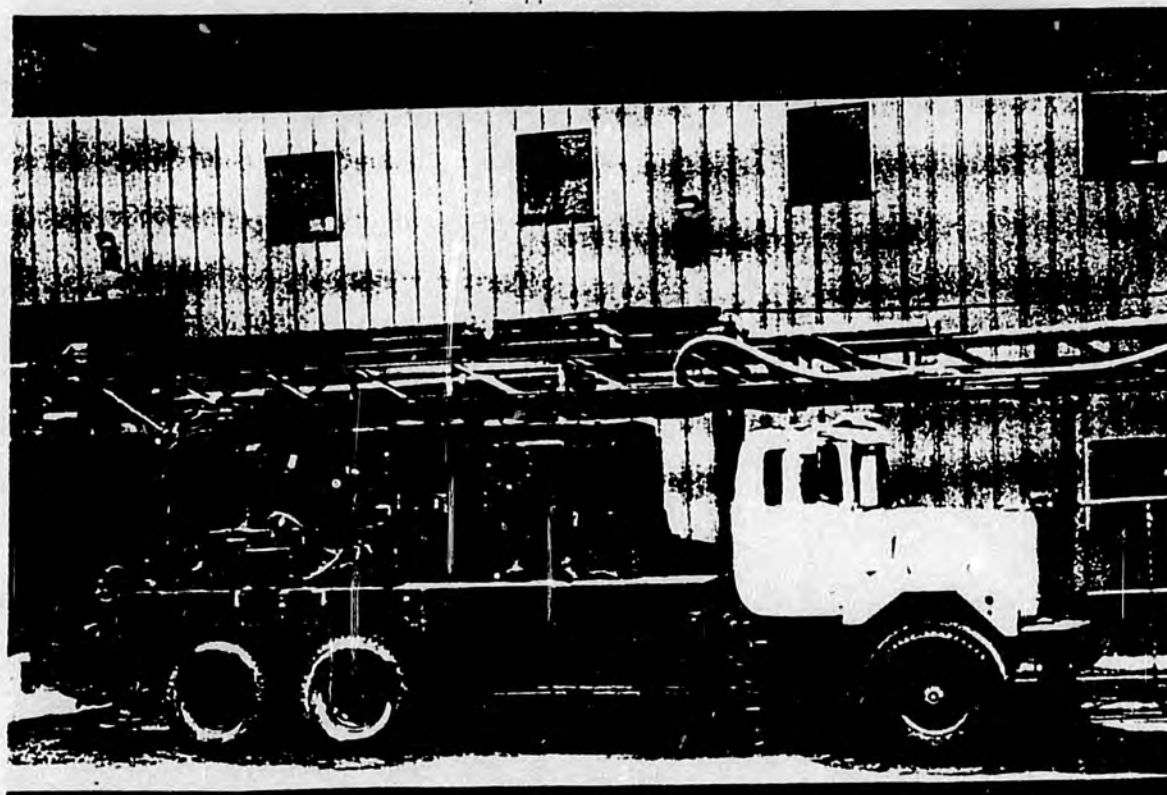


PHOTO #13

*Ambler Drilling's rotary-hammer drill rig.
courtesy, Ambler Drilling, 1995*

Alaska State Legislature

Resources, Vice Chair
State Affairs, Vice Chair
House Special Committee on Oil & Gas, Vice Chair
House Special Committee on Fisheries



State Capitol
Room 409
Juneau, Alaska 99801-1182
(907) 465-3878
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Representative Scott Ogan
House District 27

Sponsor Statement HB 394

The purpose of this bill is to encourage coal bed methane development for in state use. Currently, the state spends \$ 20 million a year on power cost equalization in rural Alaska. There is also significant economic and environmental liability associated with shipping and storing diesel fuel in rural areas.

HB 394 specifically addresses the problems that small independent gas well developers have with obtaining leases, bonding costs, and handling solid waste. The lease scenario would be over the counter for a two year period. The lease would be for in state use only. The lease area would be for 36 square miles. The bonding for possible environmental damage would be reduced due to the fact that there is very little possibility of an environmental accident. All of the proposed leases would be scrutinized by the Oil and Gas Conservation Commission to conclude with reasonable certainty that the well would not penetrate a formation containing oil.

There are tremendous coal reserves in Alaska. A typical coal bed well will produce gas at a much slower rate than a gas well associated with oil, and it will sustain this level of production for a longer period of time. Electrical generators could be converted to burn methane gas, and people could use the gas to heat their homes.

I ask for your support on this measure for the following reasons: Coal bed methane holds great potential for allowing both rural and urban Alaskan communities to become energy independent. Passage of this legislation would spur economic development by providing jobs, and by allowing small independent companies to enter into the gas market. This measure would help to lower state spending, as it would decrease the dependence upon power cost equalization.

LEGAL SERVICES

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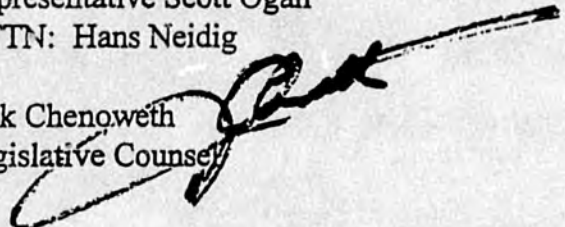
130 Seward Street, Suite 409
Juneau, Alaska 99801-2105

MEMORANDUM

January 22, 1996

SUBJECT: House Bill 394, relating to natural gas and coal bed methane development licensing and leasing -- sectional analysis (Work Order No. 9-LS1463\C)

TO: Representative Scott Ogan
ATTN: Hans Neidig

FROM: Jack Chenoweth
Legislative Counsel 

House Bill 394 concerns itself with natural gas and coal bed methane exploration and development.

Bill section 5: The principal operative provision of the measure is its bill section 5, adding a new subsection, (dd), to AS 38.05.180, part of the Alaska Land Act. Under proposed subsection (dd), the division director would be able to exercise powers substantially the same as those provided under the state's oil and gas exploration licensing provisions added by ch. 35, SLA 1994 to license to explore for natural gas and coal bed methane. A principal difference between this provision and the exploration licensing program is that exploration would be limited to "gas deposits and coal bed methane within 3,000 feet of the surface at the drill site[.]" See proposed AS 38.05.180(dd)(3)(A), at page 6, line 4.

Bill section 2: The provision proposes an amendment to the enumerated powers of the director of the division of lands to permit the director to prescribe application procedures with respect to licenses and leases under the natural gas/coal bed methane licensing and leasing program.

Bill section 3: The bill section amends AS 38.05.035(e)(6) to exempt the natural gas/coal bed methane licensing and leasing program from the requirement of a prior written best interest finding.

Bill section 4: This amendment to AS 38.05.180(b) directs the commissioner of natural resources to notify the legislature of the availability of a proposed gas licensing and leasing and coal bed methane licensing and leasing program. (The obligation imposed on the Department of Natural Resources to prepare that program is set out in the lead-in language of AS 38.05.180(dd).)

Representative Scott Ogden

January 22, 1996

Page 2

Bill section 6: The bill section proposes to expand an existing exemption from obtaining a waste water discharge permit for discharges or disposals of waste material or water from activities associated with coal bed methane exploration drilling.

Bill sections 7 - 11: Collectively, the amendments made in these five bill sections to provisions of AS 46.04 are intended to relieve operators of onshore exploration facilities used to explore for natural gas or coal bed methane from providing proof of financial responsibility as a condition of operating. However, the exemption is dependent on the facility operator's obtaining a certificate from the Alaska Oil and Gas Conservation Commission that the operator's activities will, to a reasonable certainty, not penetrate a formation containing oil. If thereafter the facility operator's activities penetrate an oil formation, the operator must cease exploration activities and comply with the requirements relating to proof of financial liability.

Bill section 1: The provision amends AS 31.05 to add, as an additional duty of the Alaska Oil and Gas Conservation Commission, determination "with reasonable certainty" that a proposed gas or coal bed methane exploration well will not penetrate an oil formation, and the obligation to so certify.

As a drafting technique, usually when a statutory provision that contains materials saying "REPEALED," the provision(s) so marked should be renumbered or reformatted to eliminate those "REPEALED" references. However, to shorten this measure's length, it does not make all those drafting changes. (To have done so would be to set out all the various identified provisions that are affected by the repealed paragraphs, inserting appropriate corrected cross-references.) Instead, **bill section 12** directs the Revisor of Statutes to revise those references.

JBC:lmb:klb

96-026.lmb

WEST VIRGINIA CODE

ANNOTATED

VOLUME 8A

1994 Replacement Volume

*(Including Acts through the 1994 Regular and
First Extraordinary Sessions)*

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THE MICHIE COMPANY

Law Publishers

CHARLOTTESVILLE, VIRGINIA

1994

ARTICLE 21.

COALBED METHANE WELLS AND UNITS.

- Sec.
- 22-21-1. Declaration of public policy; legislative findings.
- 22-21-2. Definitions.
- 22-21-3. Application of article; exclusions; application of chapter twenty-two-b to coalbed methane wells.
- 22-21-4. Chief; powers and duties generally.
- 22-21-5. Duties of the coalbed methane review board; meetings; notice; powers and duties generally.
- 22-21-6. Permit required for coalbed methane well; permit fee; application; soil erosion control plan; penalties.
- 22-21-7. Consent and agreement of coal owner or operator.
- 22-21-8. Performance bonds; corporate surety or other security.
- 22-21-9. Notice to owners.
- 22-21-10. Procedure for filing comments.
- 22-21-11. Objections or comments to coalbed methane wells by coal owner or operator; hearings.
- 22-21-12. Review of application; issuance of permit in the absence of objections; copy of permits to county assessor.
- 22-21-13. Review board hearing; findings; order.
- 22-21-14. Protective devices required when a coalbed methane well penetrates workable coal bed; when

Sec.

- a coalbed methane well is drilled through horizon of coal bed from which coal has been removed; notice of stimulation; results of stimulation.
- 22-21-15. Drilling units and pooling of interests.
- 22-21-16. Notice to owners.
- 22-21-17. Review of application; hearing; pooling order; spacing; operator; elections; working interests; royalty interests, carried interests, escrow account for conflicting claims, division order.
- 22-21-18. Operation on drilling units.
- 22-21-19. Validity of unit agreements.
- 22-21-20. Spacing.
- 22-21-21. Dry or abandoned wells.
- 22-21-22. Notice of plugging and reclamation of well; right to take well; objection; plugging order; plugging for minethrough.
- 22-21-23. Method of plugging.
- 22-21-24. Existing mining rights.
- 22-21-25. Judicial review; appeal to supreme court of appeals; legal representation for review board.
- 22-21-26. Limitation on actions in trespass.
- 22-21-27. Injunctive relief.
- 22-21-28. Penalties.
- 22-21-29. Construction.

Editor's notes. — Acts 1994, c. 61, which amended and reenacted chapter 22, substituted articles one through twenty for former articles one through thirteen. Article 21, §§ 22-21-1 to

22-21-29, was enacted by Acts 1994, c. 24.

Effective dates. — Acts 1994, c. 24 provided that the act take effect from passage (March 12, 1994).

§ 22-21-1. Declaration of public policy; legislative findings.

(a) The Legislature hereby declares and finds that the venting of coalbed methane from mine areas and degasification of coal seams has been and continues to be approved by the state for the purpose of ensuring the safe recovery of coal; that the value of coal is far greater than the value of coalbed methane and any development of the coalbed methane should be undertaken in such a way as to protect and preserve coal for future safe mining and maximum recovery of the coal; that subject to the above declarations and findings, commercial recovery and marketing of coalbed methane should in

some cases be facilitated because the energy needs of this state and the United States indicate that the fullest practical recovery of both coal and coalbed methane should be encouraged; that the Energy Policy Act of 1992 was enacted in part to encourage coalbed methane development and the state of West Virginia should enact legislation which carries out the purposes of said act; that in order to encourage and ensure the fullest practical recovery of coal and coalbed methane in this state and to further ensure the safe recovery of both natural resources, it is in the public interest to enact this article authorizing coalbed methane well permits, regulating the design of coalbed methane wells and recovery techniques, authorizing coalbed methane well units and pooling of interests therein to provide all coalbed methane operators and coalbed methane owners with an opportunity to recover their just and equitable share of production.

(b) It is hereby declared to be the public policy of this state and in the public interest to:

(1) Preserve coal seams for future safe mining; facilitate the expeditious, safe evacuation of coalbed methane from the coalbeds of this state, and maintain the ability and absolute right of coal operators at all times to vent coalbed methane from mine areas;

(2) Foster, encourage and promote the commercial development of this state's coalbed methane by establishing procedures for issuing permits and forming drilling units for coalbed methane wells without adversely affecting the safety of mining or the mineability of coal seams;

(3) Safeguard, protect and enforce the correlative rights of coalbed methane well operators and coalbed methane owners in a pool of coalbed methane to the end that each such operator and owner may obtain his or her just and equitable share of production from coalbed methane recovered and marketed under this article;

(4) Safeguard and protect the mineability of coal during the removal of coalbed methane, as permitted under this article;

(5) Create a state permitting procedure and authority to provide for and facilitate coalbed methane development as encouraged by the Energy Policy Act of 1992; and

(6) Seek the deletion of the state of West Virginia from the list of affected states by the secretary of the United States department of the interior as provided for in the Energy Policy Act of 1992. (1994, c. 24.)

§ 22-21-2. Definitions.

Unless the context in which used clearly requires a different meaning, as used in this article:

(a) "Review board" means the West Virginia coalbed methane review board which shall be comprised of the members of the West Virginia shallow gas well review board provided for in article eight [§ 22C-8-1 et seq.], chapter twenty-two-c of this code, the state geologist, a representative of the United Mine Workers of America, an employee of the gas industry, and the director of the office of miners' health, safety and training, and the chairman of the review board shall be the chairman of the West Virginia shallow gas review board;

(b) "Coalbed" unworkable, and

(c) "Coalbed" the rock or other or a gob well;

(d) "Coalbed"

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(b) "Coalbed" or "coal seam" means a seam of coal, whether workable or unworkable, and the noncoal roof and floor of said seam of coal;

(c) "Coalbed methane" means gas which can be produced from a coal seam, the rock or other strata in communication with a coal seam, a mined-out area or a gob well;

(d) "Coalbed methane owner" means any owner of coalbed methane;

(e) "Coalbed methane well" means any hole or well sunk, drilled, bored or dug into the earth for the production of coalbed methane for consumption or sale, including a gob well. The term "well" shall mean a coalbed methane well unless the context indicates otherwise. The term "coalbed methane well" does not include any shaft, hole or well sunk, drilled, bored or dug into the earth for core drilling, production of coal or water, venting gas from a mine area, or degasification of a coal seam;

(f) "Coalbed methane well operator" or "well operator" means any person who has the right to operate or does operate a coalbed methane well;

(g) "Coal operator" means any person who proposes to or does operate a coal mine;

(h) "Coal owner" means any person who owns or leases a coal seam;

(i) "Chief" means the chief of the office of oil and gas of the division of environmental protection provided for in section eight [§ 22-1-8], article one of this chapter;

(j) "Director" means the director of the division of environmental protection;

(k) "Division" means the division of environmental protection;

(l) "Gob well" means a well drilled or vent hole converted to a well pursuant to this article which produces or is capable of producing coalbed methane or other natural gas from a distressed zone created above and below a mined-out coal seam by any prior full seam extraction of the coal;

(m) "Mine" or "mine areas," including the sub-definitions under "mine areas," shall have the same definitions as are provided in section two [§ 22A-1-2], article one, chapter twenty-two-a of this code;

(n) "Office" means office of oil and gas provided for in section seven [§ 22-1-7], article one of this chapter;

(o) "Person" means any natural person, corporation, firm, partnership, partnership association, venture, receiver, trustee, executor, administrator, guardian, fiduciary, other representative of any kind, any recognized legal entity, or political subdivision or agency thereof;

(p) "Stimulate" means any action taken to increase the natural flow of coalbed methane or the inherent productivity of a coalbed methane well, including, but not limited to, fracturing, shooting, acidizing or water flooding, but excluding cleaning out, bailing or workover operations;

(q) "Waste" means (i) physical waste as the term is generally understood in the gas industry and as provided for in article six [§ 22-6-1 et seq.] of this chapter, but giving special consideration to coal mining operations and the safe recovery of coal; (ii) the locating, drilling, equipping, operating, producing or transporting coalbed methane in a manner that causes or tends to cause a substantial reduction in the quantity of coalbed methane recoverable from a pool under prudent and proper operations, or that causes or tends to cause a

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substantial or unnecessary or excessive surface loss of coalbed methane; (iii) the drilling of more wells than are reasonably required to recover efficiently and economically the maximum amount of coalbed methane from a pool; or (iv) substantially inefficient, excessive or improper use, or the substantially unnecessary dissipation of reservoir pressure. Waste does not include coalbed methane vented or released from any mine area, the degasification of a coal seam for the purpose of mining coal, the plugging of coalbed methane wells for the purpose of mining coal, or the conversion of coalbed methane wells to vent holes for the purpose of mining coal;

(r) "Workable coalbed" or "workable coal seam" means any seam of coal twenty inches or more in thickness, or any seam of less thickness which is being commercially mined or can be shown to be capable of being commercially mined. (1994, c. 24.)

§ 22-21-3. Application of article; exclusions; application of chapter twenty-two-b to coalbed methane wells.

(a) The provisions of this article apply to (1) all lands in this state under which a coalbed is located, including any lands owned or administered by the state or any agency or subdivision thereof, and (2) any coalbed methane well.

(b) This article does not apply to or affect (1) any well otherwise permitted, approved or regulated under article six, seven, eight, nine or ten [§ 22-6-1 et seq., § 22-7-1 et seq., § 22-8-1 et seq., § 22-9-1 et seq., or § 22-10-1] of this chapter or article eight [§ 22C-8-1 et seq.], chapter twenty-two-c of this code, (2) any ventilation fan, vent hole, mining apparatus, or other facility utilized solely for the purpose of venting any mine or mine area, or (3) the ventilation of any mine or mine area or degasification of any coal seam for the mining of coal.

(c) This article does not apply to or affect subsurface boreholes drilled from the mine face of an underground mine, except that the provisions of sections fifteen, sixteen, seventeen, eighteen and nineteen [§§ 22-21-15, 22-21-16, 22-21-17, 22-21-18 and 22-21-19] shall apply.

(d) To the extent that coalbed methane wells are similar to wells, as defined in section one [§ 22-6-1], article six of this chapter of this code, and the production of coalbed methane is similar to the production of natural gas, coalbed methane wells shall be treated as wells and coalbed methane treated as natural gas and subject to the following sections of article six of this chapter:

(1) The provisions of section three [§ 22-6-3] pertaining to the findings and orders of inspectors concerning violations, determination of reasonable time for abatement, extensions of time for abatement, special inspections, notice of findings and orders;

(2) The provisions of section four [§ 22-6-4] providing for the review of findings and orders by the chief, special inspection, annulment, revision of order and notice;

(3) The provisions of section five [§ 22-6-5] providing for the requirements of findings, orders and notices; posting of findings and orders; and judicial review of final orders of the chief;

albed methane; (iii) to recover efficiently from a pool; or (iv) the substantially not include coalbed gasification of a coal and methane wells for methane wells to vent

s any seam of coal thickness which is being commercially

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in this state under administered by the albed methane well. otherwise permitted, or ten [§ 22-6-1 et or § 22-10-1] of this ty-two-c of this code, other facility utilized or (3) the ventilation am for the mining of

oreholes drilled from provisions of sections 22-21-15, 22-21-16,

ar to wells, as defined of this code, and the action of natural gas, albed methane treated cle six of this chapter: ng to the findings and on of reasonable time inspections, notice of

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(4) The provisions of section twenty-one [§ 22-6-21] providing for protective devices—installation of freshwater casings;

(5) The provisions of section twenty-two [§ 22-6-22] providing for a well log to be filed, contents, and authority to promulgate regulations. In addition to the requirements of such section, the operator shall certify that the well was drilled and completed as shown on the well plat required for a coalbed methane well, or in the alternative, file a revised well plat showing the actual location of the well and the coal seams in which the well is completed for production. Such log and certificate shall be served on all coal owners and operators who must be named in the permit application under section six [§ 22-21-6] of this article;

(6) The provisions of section twenty-eight [§ 22-6-28] providing for supervision by the chief over drilling and reclamation operations, complaints, hearings and appeals;

(7) The provisions of section twenty-nine [§ 22-6-29] providing for special reclamation funds and fees;

(8) The provisions of section thirty [§ 22-6-30] providing for reclamation requirements;

(9) The provisions of section thirty-one [§ 22-6-31] providing for preventing waste of gas, plan of operation required for wasting gas in process of producing oil and rejection thereof;

(10) The provisions of section thirty-two [§ 22-6-32] providing for the right of adjacent owner or operator to prevent waste of gas and recovery of costs;

(11) The provisions of section thirty-three [§ 22-6-33] providing for restraining waste;

(12) The provisions of section thirty-four [§ 22-6-34] providing for offenses and penalties;

(13) The provisions of section thirty-five [§ 22-6-35] providing for civil action for contamination or deprivation of freshwater source or supply and presumption;

(14) The provisions of section thirty-six [§ 22-6-36] providing for declaration of notice by owners and lessees of coal seams and setting out the form of such declaration; and

(15) The provisions of section thirty-nine [§ 22-6-39] providing for injunctive relief.

In addition to the foregoing and subject to the same qualifications, the provisions of article ten [§ 22-10-1 et seq.] of this chapter shall apply to coalbed methane wells. Any well which is abandoned or presumed to be abandoned under the provisions of this article shall be treated as an abandoned well under said article ten. (1994, c. 24.)

§ 22-21-4. Chief; powers and duties generally.

(a) The chief of the office of oil and gas shall have the duty of issuing permits and otherwise supervising the execution and enforcement of the provisions of this article, all subject to the review and approval of the director.

(b) The chief of the office of oil and gas is authorized to enact rules necessary to effectuate the purposes of this article, subject to the review and approval by the director.

§ 22-21-5

ENVIRONMENTAL RESOURCES

(c) In addition to all other powers and duties conferred upon the chief, the chief shall have the power and duty to:

(1) Perform all duties which are expressly imposed upon him by the provisions of this article, as well as duties assigned to him or her by the director;

(2) Perform all duties as the permit issuing authority for the state in all matters pertaining to the exploration, development, production and recovery of coalbed methane in accordance with the provisions of this article;

(3) Perform such acts as may be necessary or appropriate to secure to this state the benefits of federal legislation by establishing programs relating to the exploration, development, production and recovery of coalbed methane, which programs are assumable by the state;

(4) Visit and inspect any coalbed methane well or well site and call for the assistance of any oil and gas inspectors or other employees of the office of oil and gas in the enforcement of the provisions of this article;

(5) Collect the permit application fee for the drilling of a coalbed methane well;

(6) Collect the permit application fee for a drilling unit. (1994, c. 24.)

§ 22-21-5. Duties of the coalbed methane review board; meetings; notice, powers and duties generally.

(a) The board shall meet and hold conferences and hearings at such times and places as are designated by the chairman. The chairman may call a meeting of the board at any time. The chairman shall call a meeting of the board (1) upon receipt from the chief of a completed application for a permit to establish one or more coalbed methane gas drilling units pursuant to this article, (2) upon receipt from the chief of a request pursuant to section seven [§ 22-21-7] of this article or comments or objections pursuant to sections ten and eleven [§§ 22-21-10 and 22-21-11] of this article, or (3) within twenty days upon the written request by another member of the board. Notice of all meetings shall be given to each member of the board by the chairman at least ten days in advance thereof, unless otherwise agreed by the members.

(b) At least ten days prior to every meeting of the board called pursuant to the provisions of this section, the chairman shall also notify the applicant, all persons to whom copies of the application were required to be mailed pursuant to the provisions of section nine of this article and all persons who filed written protests or objections with the board in accordance with the provisions of section ten or eleven [§ 22-21-10 or § 22-21-11] of this article.

(c) A majority of the members of the board constitute a quorum for the transaction of any business. A majority of the members of the board is required to determine any issue brought before it.

(d) The board shall execute and carry out, administer and enforce the provisions of this article in the manner provided herein. Subject to the provisions of section three [§ 22-21-3] of this article, the board has jurisdiction and authority over all persons and property necessary therefor: Provided, That the provisions of this article do not grant to the board authority or power to fix prices of coalbed methane gas.

(e) Within eighteen months of the effective date of this article, the board shall initiate rule-making proceedings to investigate the feasibility of establishing blanket bonds for financial security in addition to the provisions for bonds for financial security under section thirteen [§ 22-21-13] of this article.

(f) The board may:

(1) Take evidence and issue orders concerning applications for drilling permits and coalbed methane gas drilling units in accordance with the provisions of this article;

(2) Promulgate, pursuant to the provisions of chapter twenty-nine-a [§ 29A-1-1 et seq.] of this code, and enforce reasonable rules necessary to govern the practice and procedure before the board;

(3) Make such relevant investigations of records and facilities as it deems proper; and

(4) Issue subpoenas for the attendance of and sworn testimony by witnesses and subpoenas duces tecum for the production of any books, records, maps, charts, diagrams and other pertinent documents in its own name or at the request of any party pursuant to article five [§ 29A-5-1 et seq.], chapter twenty-nine-a. (1994, c. 24.)

Editor's notes. — Concerning the effective date of this section, Acts 1994, the reference in (e) to c. 24, which enacted this section, provided

that the act take effect from passage (March 12, 1994).

§ 22-21-6. Permit required for coalbed methane well; permit fee; application; soil erosion control plan; penalties.

(a) It is unlawful for any person to commence, operate, deepen or stimulate any coalbed methane well, to conduct any horizontal drilling of a well commenced from the surface for the purpose of commercial production of coalbed methane, or to convert any existing well, vent hole or other hole to a coalbed methane well, including in any case site preparation work which involves any disturbance of land, without first securing from the chief a permit pursuant to this article.

(b) Every permit application filed under this section shall be verified and shall contain the following:

(1) The names and addresses of (i) the well operator, (ii) the agent required to be designated under subsection (e) of this section, and (iii) every person or entity whom the applicant must notify under any section of this article;

(2) The name and address of each coal operator and each coal owner of record or providing a record declaration of notice pursuant to section thirty-six [§ 22-6-36], article six of this chapter of any coal seam which is (i) to be penetrated by a proposed well, (ii) within seven hundred fifty horizontal feet of any portion of the proposed well bore; or (iii) within one hundred vertical feet of the designated completion coal seams of the proposed well, except that in the case of an application to convert a ventilation hole to a gob well, the name and address only of such owner or operator of the seams to be penetrated by a proposed well shall be necessary;

- (3) The well name or such other identification as the chief may require;
 - (4) The approximate depth to which the well is to be drilled, deepened or converted, the coal seams (stating the depth and thickness of each seam) in which the well will be completed for production, and any other coal seams (including the depth and thickness of each seam) which will be penetrated by the well;
 - (5) A description of any means to be used to stimulate the well;
 - (6) If the proposed well will require casing or tubing to be set, the entire casing program for the well, including the size of each string of pipe, the starting point and depth to which each string is to be set, and the extent to which each such string is to be cemented;
 - (7) If the proposed operation is to convert an existing well, as defined in section one [§ 22-6-1], article six of this chapter, or to convert a vertical ventilation hole to a coalbed methane well, all information required by this section, all formations from which production is anticipated, and any plans to plug any portion of the well;
 - (8) Except for a gob well or vent hole proposed to be converted to a well, if the proposed coalbed methane well will be completed in some but not all coal seams for production, a plan and design for the well which will protect all workable coal seams which will be penetrated by the well;
 - (9) If the proposed operations will include horizontal drilling of a well commenced on the surface, a description of such operations, including both the vertical and horizontal alignment and extent of the well from the surface to total depth;
 - (10) Any other relevant information which the chief may require by rule.
- (c) Each application for a coalbed methane well permit shall be accompanied by the following:
- (1) The applicable bond prescribed by section eight [§ 22-21-8] of this article;
 - (2) A permit application fee of two hundred fifty dollars;
 - (3) The erosion and sediment control plan required under subsection (d) of this section;
 - (4) The consent and agreement of the coal owner as required by section seven [§ 22-21-7] and, if applicable, section twenty [§ 22-21-20] of this article;
 - (5) A plat prepared by a licensed land surveyor or registered engineer showing the district and county in which the drill site is located, the name of the surface owner of the drill site tract, the acreage of the same, the names of the surface owners of adjacent tracts, the names of all coal owners underlying the drill site tract, the proposed or actual location of the well determined by a survey, the courses and distances of such location from two permanent points or landmarks on said tract, the location of any other existing or permitted coalbed methane well or any oil or gas well located within two thousand five hundred feet of the drill site, the number to be given the coalbed methane well, the proposed date for completion of drilling, the proposed date for any stimulation of the well, and if horizontal drilling of a well commenced on the surface is proposed, the vertical and horizontal alignment and extent of the well;

(6) A certificate by the applicant that the notice requirements of section nine [§ 22-21-9] of this article have been satisfied by the applicant. Such certification may be by affidavit of personal service, or the return receipt card, or other postal receipt, for certified mailing.

(d) An erosion and sediment control plan shall accompany each application for a permit. Such plan shall contain methods of stabilization and drainage, including a map of the project area indicating the amount of acreage disturbed. The erosion and sediment control plan shall meet the minimum requirements of the West Virginia erosion and sediment control manual as adopted and from time to time amended by the office of oil and gas in consultation with the several soil conservation districts pursuant to the control program established in this state through section 208 of the federal Water Pollution Control Act Amendments of 1972. The erosion and sediment control plan shall become part of the terms and conditions of a permit and the provisions of the plan shall be carried out where applicable in operations under the permit. The erosion and sediment control plan shall set out the proposed method of reclamation which shall comply with the requirements of section thirty [§ 22-6-30], article six of this chapter.

(e) The well operator named in such application shall designate the name and address of an agent for such operator who shall be the attorney-in-fact for the operator and who shall be a resident of the state of West Virginia, upon whom notices, orders or other communications issued pursuant to this article may be served, and upon whom process may be served. Every well operator required to designate an agent under this section shall within five days after the termination of such designation notify the office of such termination and designate a new agent.

(f) The well owner or operator shall install the permit number as issued by the chief in a legible and permanent manner to the well upon completion of any permitted work. The dimensions, specifications and manner of installation shall be in accordance with the rules of the chief.

(g) The chief shall deny the issuance of a permit if he or she determines that the applicant has committed a substantial violation of a previously issued permit, including the erosion and sediment control plan, or a substantial violation of one or more of the rules promulgated hereunder, and has failed to abate or seek review of the violation. In the event that the chief finds that a substantial violation has occurred with respect to existing operations and that the operator has failed to abate or seek review of the violation in the time prescribed, he or she may suspend the permit on which said violation exists, after which suspension the operator shall forthwith cease all work being conducted under the permit until the chief reinstates the permit, at which time the work may be continued. The chief shall make written findings of any such determination made by him or her and may enforce the same in the circuit courts of this state and the operator may appeal such suspension pursuant to the provisions of section twenty-five [§ 22-21-25] of this article. The chief shall make a written finding of any such determination.

(h) Any person who violates any provision of this section shall be guilty of a misdemeanor, and, upon conviction thereof, shall be fined not more than five

thousand dollars, or be imprisoned in the county jail not more than twelve months, or both fined and imprisoned. (1994, c. 24.)

Editor's notes. — The federal Water Pollution Control Act Amendments of 1972 are codified as 33 U.S.C. 1288 et seq.

§ 22-21-7. Consent and agreement of coal owner or operator.

(a) No permit shall be issued for a coalbed methane well unless and until the applicant has obtained and filed with the chief a consent and agreement from each owner and each operator of any workable coal seam twenty-eight inches or more in thickness which is within seven hundred fifty horizontal feet of the proposed well bore and (i) which coal seam the applicant proposes to stimulate or (ii) which coal seam is within one hundred vertical feet above or below a coal seam which the applicant proposes to stimulate. The requirement for consent and agreement contained in this section shall not be considered to impair, abridge or affect any contractual rights or objections arising out of a contract or lease which provides for the development of coalbed methane and stimulation of wells between the applicant and any coal owner or operator and the existence of any such contract or lease shall constitute a waiver of the requirement to file an additional signed consent and agreement. Such consent and agreement must provide: (i) That such coal owner or operator has been provided with a copy of the application for permit as required by section six [§ 22-21-6] of this article and with a copy of all plats and documents which must accompany the application and (ii) that such coal owner or operator consents and agrees to the stimulation of the coal seam as described in such application.

(b) In the absence of the applicant submitting the consent described in subsection (a) above, the applicant may submit a request for hearing before the board accompanied by an affidavit which shall include the following:

(1) A statement that a coal owner or operator as described in subsection (a) of this section has refused to provide written authorization to stimulate the well;

(2) A statement detailing the efforts undertaken to obtain such authorization;

(3) A statement setting out any known reasons for the authorization not being provided;

(4) A statement or other information in addition to that provided pursuant to subdivision (5), subsection (b), section six [§ 22-21-6(b)(5)] of this article necessary to provide prima facie evidence that the proposed method of stimulation will not render the coal seam unworkable, or considering all factors, impair mine safety.

(c) Upon receipt of a request and affidavit as set forth in subsection (b) of this section, the chief shall forward the application to the board to consider the proposed stimulation, or if other objections or notices are filed requiring a hearing before the board, the request hereunder may be included for consideration by the board along with other matters related to the application.

(d) If the authorization of a coal owner or operator has been withheld based upon reasons related to safety, the chief shall, concurrent with submission of the request and affidavit to the board, submit a copy of the application to the director of the office of miners' health, safety and training who shall review the application as to issues of mine safety and within thirty days submit recommendations to the board. (1994, c. 24.)

§ 22-21-8. Performance bonds; corporate surety or other security.

(a) No permit shall be issued pursuant to this article unless a bond is or has been furnished as provided in this section.

(b) A separate bond may be furnished for a particular coalbed methane well in the sum of ten thousand dollars, payable to the state of West Virginia, conditioned on full compliance with all laws and rules relating to the drilling, operation and stimulation of such wells, to the plugging, abandonment and reclamation thereof, and for furnishing such reports and information as may be required by the chief.

(c) When an operator makes or has made application for permits to drill, operate or stimulate more than one coalbed methane well or a combination of coalbed methane wells and wells regulated under article one [§ 22B-1-1 et seq.], chapter twenty-two-b of this code, the operator may in lieu of furnishing a separate bond furnish a blanket bond in the sum of fifty thousand dollars, payable to the state of West Virginia, and conditioned as stated in subsection (b) of this section.

(d) All bonds submitted hereunder shall have a corporate bonding or surety company authorized to do business in the state of West Virginia as surety thereon, or in lieu of a corporate surety, the operator may elect to deposit with the chief cash, collateral securities or any combination thereof as provided for in subsection (d), section twenty-six [§ 22-6-26(d)], article six of this chapter.

(e) For purposes of bonding requirements, a coalbed methane well shall be treated as a well, as defined and regulated in article one [§ 22B-1-1 et seq.], chapter twenty-two-b of this code, and the provisions of subsections (e), (g), (h), (i) and (j) of section twenty-six [§§ 22B-1-26(e), 22B-1-26(g), 22B-1-26(h), 22B-1-26(i) and 22B-1-26(j)] thereof shall apply. (1994, c. 24.)

Editor's notes. — Section 22B-1-26, referred to in (e) above, was repealed by Acts 1944, c. 61. A similar provision is now codified at § 22-6-26.

§ 22-21-9. Notice to owners.

(a) Prior to filing an application for a permit for a coalbed methane well under this article, the applicant shall deliver by personal service or by certified mail, return receipt requested, copies of the application, well plat and erosion and sediment control plan to the following:

(1) The owners of record of the surface of the tract on which the coalbed methane well is to be located;

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(2) The owners of record of the surface of any tract which is to be utilized for roads or other land disturbance;

(3) Each coal owner and each coal operator (i) from whom a consent and agreement provided for in section seven [§ 22-21-7] of this article is required, or (ii) whose coal seam will be penetrated by the proposed coalbed methane well or is within seven hundred fifty feet of any portion of the well bore; and

(4) Each owner and lessee of record and each operator of natural gas surrounding the well bore and existing in formations above the top of the uppermost member of the "Onondaga Group" or at a depth less than six thousand feet, whichever is shallower. Notices to gas operators shall be sufficient if served upon the agent of record with the office of oil and gas.

(b) If more than three tenants in common or other co-owners of interests described in subsection (a) of this section hold interests in such lands, the applicant may serve the documents required upon the person described in the records of the sheriff required to be maintained pursuant to section eight [§ 11A-1-8], article one, chapter eleven-a of this code; provided, that all owners and operators occupying or operating on the tracts where the well work is proposed to be located at the filing date of the permit application shall receive actual service of the documents required by subsection (a) of this section.

(c) Prior to filing an application for a permit for a coalbed methane well under this article, the applicant shall cause to be published in the county in which the well is located or to be located a Class II legal advertisement as described in section two [§ 59-3-2], article three, chapter fifty-nine of this code, containing such notice and information as the chief shall prescribe by rule, with the first publication date being no more than ten days after the filing of the permit application.

(d) Materials served upon persons described in subsections (a) and (b) of this section shall contain a statement of the methods and time limits for filing comment and objection, who may file comment and objection, the name and address of the chief with whom the comment and objection must be filed, the ability to obtain additional information from the chief, the fact that such persons may request notice of the permit decision, and a list of persons qualified to test water as provided in this section.

(e) Any person entitled to submit comment or objection shall also be entitled to receive a copy of the permit as issued or a copy of the order denying the permit if such person requests the receipt thereof as a part of the comment or objection concerning said permit application.

(f) Persons entitled to notice may contact the district office of the office of oil and gas to ascertain the names and location of water testing laboratories in the area capable and qualified to test water supplies in accordance with standard accepted methods. In compiling such list of names the office of oil and gas shall consult with the state and local health departments. (1994, c. 24.)

§ 22-21-10. Procedure for filing comments.

All persons described in subsection (a), section nine [§ 22-21-9(a)] of this article may file comments with the chief as to the location or construction of the

applicant's proposed well within fifteen days after the application is filed with the chief. (1994, c. 24.)

§ 22-21-11. Objections or comments to coalbed methane wells by coal owner or operator; hearings.

The owner or operator of any coal seam whose interests may be adversely affected by a coalbed methane well may, within fifteen days from the receipt of notice required by section nine [§ 22-21-9] of this article, file objections in writing to such proposed drilling with the chief, setting out the grounds on which such objections are based. (1994, c. 24.)

§ 22-21-12. Review of application; issuance of permit in the absence of objections; copy of permits to county assessor.

The chief shall review each application for a permit and shall determine whether or not a permit shall be issued.

No permit shall be issued less than fifteen days after the filing date of the application for any well work except plugging or replugging; and no permit for plugging or replugging shall be issued less than five days after the filing date of the application except a permit for plugging or replugging a dry hole: Provided, That if the applicant certifies that all persons entitled to notice of the application under the provisions of this article have been served in person or by certified mail, return receipt requested, with a copy of the permit application, including the erosion and sediment control plan, if required, and the plat required by section six [§ 22-21-6] of this article, and further files written statements of no objection by all such persons, the chief may issue the permit at any time.

The chief may cause such inspections to be made of the proposed location as to assure adequate review of the application. The permit shall not be issued, or shall be conditioned, including conditions with respect to the location of the well and access roads, prior to issuance if the chief determines that:

- (1) The proposed well work will constitute a hazard to the safety of persons; or
- (2) The plan for soil erosion and sediment control is not adequate or effective; or
- (3) Damage would occur to publicly owned lands or resources; or
- (4) The proposed well work fails to protect fresh water sources or supplies.

Upon the issuance of any permit pursuant to the provisions of this article, the chief shall transmit a copy of such permit to the office of the assessor for the county in which the well is located. (1994, c. 24.)

§ 22-21-13. Review board hearing; findings; order.

- (a) If comment or objection is filed under section ten or eleven [§ 22-21-10 or § 22-21-11] of this article, the chief shall forthwith provide to the chairman of

the coalbed methane review board a copy of any such objection or comment, together with the application for a permit for the coalbed methane well in question, the plat filed therewith and such other information accompanying the permit as may relate to the comment or grounds for the objection.

(b) The review board shall forthwith schedule a hearing for the purpose of considering such objection or comment. Notice shall be given fifteen days in advance of the hearing to any person filing comment or objection, and to any person to whom notice of the application required, and to any applicant, and the review board shall hold such hearing within thirty days after the deadline for filing objection or comment. At such hearing the review board shall consider the matters raised in any objection or comment, including surface topography and use, and with respect to the ability to mine any affected coal seam safely and the protection of any such seam for future mining shall consider the following:

(1) Whether the drilling location is above or in close proximity to any mine opening, shaft, entry, travelway, airway, haulageway, drainageway or passageway, or to any proposed extension thereof, any abandoned, operating coal mine or any coal mine already surveyed and platted but not yet being operated;

(2) Whether the proposed drilling can reasonably be done through an existing or planned pillar of coal, or in close proximity to an existing or planned pillar of coal, taking into consideration the surface topography;

(3) Whether the proposed well can be drilled safely, taking into consideration the dangers from creeps, squeezes or other disturbances due to the extraction of coal;

(4) The extent to which the proposed drilling location unreasonably interferes with the safe recovery of coal or coalbed methane;

(5) The extent to which the proposed drilling location will unreasonably interfere with present or future coal mining operations on the surface including, but not limited to, operations subject to the provisions of article three [§ 22-3-1 et seq.] of this chapter;

(6) The feasibility of moving the proposed drilling location to a mined-out area, below the coal outcrop, or to some other location;

(7) The feasibility of a drilling moratorium for not more than one year in order to permit the completion of imminent coal mining operations;

(8) The methods proposed for the recovery of coal and coalbed methane;

(9) The practicality of locating the well on a uniform pattern with other wells;

(10) The surface topography and use;

(11) Whether any stimulation of the coal seam will render such seam or any other workable coal seams unmineable or unsafe for mining; and

(12) Whether the director of the office of miners' health, safety and training has submitted recommendations as to the safety of any proposed stimulation. In considering any recommendations made by the director of the office of miners' health, safety and training, the board shall incorporate such recommendations in its findings, conclusions and order unless the board determines that there is clear and convincing evidence on the record supporting a finding, conclusion or order inconsistent with such recommendations.

(c) In weighing the evidence presented to the board the applicant shall have the burden of proving by clear and convincing evidence that stimulation of a workable coal seam of twenty-eight inches or more in thickness will not render such seam or any other workable coal seam of twenty-eight inches or more in thickness unmineable or unsafe for mining.

(d) Upon consideration of the matters raised at the hearing, the review board shall render a decision based upon the ability to mine any affected coal seam safely and the protection of any coal seam for safe future mining, shall enter a written order containing findings of fact and conclusions which address any relevant considerations in subsection (b) of this section and based thereon shall issue and file with the chief a written order directing him to:

- (1) Refuse a drilling permit; or
- (2) Issue a drilling permit for the proposed drilling location; or
- (3) Issue a drilling permit for an alternate drilling location different from that requested by the applicant; or
- (4) Issue a drilling permit either for the proposed drilling location or for an alternative drilling location different from that requested by the applicant, provided such alternate location is covered by the agreement and consent required by section seven [§ 22-21-7] of this article, but not allow the drilling of the well for a period of not more than one year from the date of issuance of such permit; or

(5) Issue a permit authorizing the applicant to stimulate the well in the absence of consent of the affected coal operators or owners of workable coal seams of twenty-eight inches or more in thickness as described in subsection (a) of section seven [§ 22-21-7(a)] of this article, as proposed or as modified by the order of the board. Such order shall further provide for the applicant to furnish evidence of financial security in one of the following forms: (a) A corporate surety bond having on it a company authorized to do business in this state as surety; (b) bonds of the United States or agency thereof, or those guaranteed by, or for which the credit of the United States or agency therefor is pledged for the payment of the principal and interest thereof; (c) direct general obligation bonds of this state, or any other state, or territory of the United States, or the District of Columbia if such other state, territory or the District of Columbia has the power to levy taxes for the payment of the principal and interest of such securities, and if at the time of the deposit such other state, territory or the District of Columbia is not in default in the payment of any part of the principal or interest owing by it upon any part of its funded indebtedness; (d) direct general obligation bonds of any county, district, city, town, village, school district or other political subdivision of this state issued pursuant to law and payable from ad valorem taxes levied on all taxable property located herein, that the total indebtedness after deducting sinking funds and all debts incurred for self-sustaining public works does not exceed five percent of the assessed value of all taxable property therein at the time of the last assessment made before the date of such deposit, and that the issuer has not, within five years prior to the making thereof, been in default for more than ninety days in the payment of any part of the principal or interest on any debt, evidenced by its bonds; (e) revenue bonds issued by this state or any

agency of this state when such bonds are payable from revenues or earnings specifically pledged for the payment of principal and interest, and a lawful sinking fund or reserve fund has been established and is being maintained for the payment of such bonds; (f) revenue bonds issued by a municipality in this state for the acquisition, construction, improvement or extension of a waterworks system, or a sewerage system, or a combined waterworks and sewerage system, when such bonds are payable from revenue or earnings specifically pledged for the payment of principal and interest, and a lawful sinking fund or reserve fund has been established and is being maintained for the payment of such bonds; (g) revenue bonds issued by a public service board of a public service district in this state for the acquisition, construction, improvement or extension of any public service properties, or for the reimbursement of payment of the costs and expenses of creating the district, when such bonds are payable from revenue or earnings specifically pledged for the payment of principal and interest, and a lawful sinking fund or reserve fund has been established and is being maintained for the payment of such bonds; (h) revenue bonds issued by a board of trustees of a sanitary district in this state for the corporate purposes of such district, when such bonds are payable from revenue or earnings specifically pledged for the payment of principal and interest, and a lawful sinking fund or reserve fund has been established and is being maintained for the payment of such bonds; and (i) bonds issued by a federal land bank or home owners' loan corporation; (j) cash; or (k) any combination of the above. The operator of the well shall be entitled to all interest and income earned on the collateral securities provided pursuant to the order. Such security given shall be placed in an escrow account. The operator providing security shall be entitled from time to time to receive, upon written order of the board, the whole or any portion of such securities upon depositing in lieu thereof cash equal to the approved securities of the classes herein specified.

The amount of such financial security shall be set by order of the board but shall in no event exceed an amount of fifty thousand dollars. In setting the amount of financial security, the board shall consider the total amount of coal which could be at risk of economic harm, demonstrated experience in the locale and seams of the proposed stimulation, the probability of damages to the seam and the likelihood of commercial recovery within thirty years of the date of stimulation.

Such financial security shall remain in force until two years after the affected coal is mined or for a period of thirty years after stimulation of the coal seam or until final resolution of any action timely instituted to collect the bond proceeds, whichever first occurs.

Any coal owner or operator may assert a claim to the posted financial security by instituting an action therefor in the circuit court of the county where the well is located or where the damages occurred.

Upon receipt of such review board order, the chief shall promptly undertake the action directed by the review board, provided that all other provisions of this article have been complied with. All permits issued by the chief pursuant to this section shall be effective ten days after issuance unless the review board orders the chief to stay the effectiveness of a permit for a period not to exceed thirty days from the date of issuance.

If a permit is issued, the chief shall indicate the approved drilling location on the plat filed with the application for a permit and shall number and keep an index of and docket each plat, the name of the well operator, the names and addresses of all persons notified, the dates of conferences, hearings and all other actions taken by the chief and the review board. The chief shall also prepare a record of the proceedings, which record shall include all applications, plats and other documents filed with the chief, all notices given and proof of service thereof, all orders issued, all permits issued and a transcript of the hearing. The record prepared by the chief shall be open to inspection by the public.

(e) Notwithstanding any finding or determination made by the board, in the event a workable coal seam twenty-eight inches or more in thickness is stimulated absent the consent of the coal owner or operator, the applicant and well operator shall be liable in tort without proof of negligence for any damage to such coal seam stimulated or any other workable coal seam twenty-eight inches or more in thickness within seven hundred fifty horizontal feet or one hundred vertical feet of the stimulation and for damages to any mining equipment proximately caused by such stimulation. Such applicant and well operator shall indemnify and hold the coal owner and coal operator harmless against any liability for injury, death or damage to property proximately caused by the stimulation. (1994, c. 24.)

§ 22-21-14. Protective devices required when a coalbed methane well penetrates workable coal bed; when a coalbed methane well is drilled through horizon of coal bed from which coal has been removed; notice of stimulation; results of stimulation.

(a) Except for those coalbeds which the coalbed methane operator proposes to complete for production of coalbed methane or where a ventilation hole is being converted to a well, when a well penetrates one or more workable coal beds, the well operator shall run and cement a string of casing in the hole through the workable coalbed or beds in such a manner as will exclude all oil, gas or gas pressure as may be found in such coalbed or beds. Such string of casing shall be circulated and cemented in such a manner as provided for in reasonable rules promulgated by the chief in accordance with the provisions of chapter twenty-nine-a [§ 29A-1-1 et seq.]. After any such string of casing has been so run and cemented to the surface, drilling may proceed to the permitted depth.

(b) When a coalbed methane well is drilled through the horizon of a coalbed from which the coal has been removed, the hole shall be drilled at least thirty feet below the coalbed, of a size sufficient to permit the placing of a liner which shall start not less than twenty feet above it. Within this liner, which may be welded to the casing to be used, shall be centrally placed the largest sized casing to be used in the well, and the space between the liner and casing shall

be filed with cement as they are lowered into the hole. Cement shall be placed in the bottom of the hole to a depth of twenty feet to form a sealed seat for both liner and casing. Following the setting of the liner, drilling shall proceed in the manner provided above. Should it be found necessary to drill through the horizon of two or more workable coalbeds from which the coal has been removed, such liner shall be started not less than twenty feet below the lowest such horizon penetrated and shall extend to a point not less than twenty feet above the highest such horizon.

(c) At least five days prior to the stimulation of any coal seam the well operator shall give the coal owner and operator notice of the date and time of stimulation and shall allow the coal owner or operator to have an observer present at the site at the coal owner or operator's risk and cost. Within thirty days after stimulation is completed, the well operator shall certify the actual stimulation procedure used including, but not limited to, the fluid injection rate, the injection pressure, the volume and components of fluid injected and the amount and components of the propping agent, if any.

(d) The chief may grant variances to the requirements of this section where such variance would promote the extraction of coalbed methane without affecting mine safety. (1994, c. 24.)

§ 22-21-15. Drilling units and pooling of interests.

(a) In the absence of a voluntary agreement, an operator, owner or other party claiming an ownership interest in the coalbed methane may file an application with the chief to pool (i) separately owned interests in a single tract, (ii) separately owned tracts, (iii) separately owned interests in any tract, and (iv) any combination of (i), (ii) and (iii) to form a drilling unit for the production of coalbed methane from one or more coalbed methane wells.

(b) The application for a drilling unit may accompany the application for a permit for a coalbed methane well or be filed as a supplement to the permit application. Such application shall be verified by the applicant and contain the following information for the proposed unit:

(1) The identity of each well and operator as set out in the well permit application;

(2) Each well number, if one has been assigned;

(3) The acreage of the proposed unit, the identity and acreage of each separate tract to be included in the proposed unit, and, where parts of tracts are included, the acreage of such parts;

(4) The district and county in which the unit is located;

(5) The names and addresses of the owners of the coal and coalbed methane underlying each separate tract, or the portion thereof which is to be included in the unit, any lessees or operators thereof, any coalbed methane owners not otherwise named, and any other claimants thereto known to the applicant. When any coal seam is separately owned, the list of names shall identify such separate ownership giving the names of the separately owned seams;

(6) A statement describing the actions taken by the applicant to obtain a voluntary agreement from each interest owner or claimant named in the application from which agreement has not been obtained;

(7) Other rules.

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(7) Other pertinent and relevant information as the chief may prescribe by rules.

(c) The application for a drilling unit shall be accompanied with the following:

(1) A plat prepared by a licensed land surveyor or registered professional engineer showing the location of the coalbed methane well or wells, or proposed well or wells, the boundary and acreage of the proposed drilling unit, the boundary and acreage of each tract contained in the unit and, where parts of tracts are included, the boundary and acreage of such parts, a name identification of each tract, and the district and county in which the unit is located. All boundaries must be shown with courses and distances;

(2) A permit application fee of two hundred fifty dollars;

(3) A certificate by the applicant that the notice requirements of section sixteen [§ 22-21-16] of this article were satisfied by the applicant. Such certification may be by affidavit of personal service, or the return receipt card, or other postal receipt, for certified mailing;

(4) An estimate of the cost, or the actual cost if known, of drilling, completing, equipping, operating, plugging and abandoning any well or wells in the proposed unit. (1994, c. 24.)

§ 22-21-16. Notice to owners.

(a) At least thirty days prior to the date set for hearing under section seventeen [§ 22-21-17] of this article, the applicant shall deliver by personal service or by certified mail, return receipt requested, notice to the following:

(1) Each coal owner and coal operator of any coal seam underlying any tract or portion thereof which is proposed to be included in the unit;

(2) Each owner and lessee of record and each operator of natural gas surrounding the well bore and existing in formations above the top of the uppermost member of the "Onondaga Group" or at a depth less than six thousand feet, whichever is shallower. Notices to gas operators shall be sufficient if served upon the agent of record with the office of oil and gas;

(3) Any coalbed methane owner to the extent not otherwise named; and

(4) Any other person or entity known to the operator to have an interest in the coal or coalbed methane.

(b) The notice required by subsection (a) of this section shall specify a time and place for a conference and a hearing on this application, shall advise the persons notified that the applicant has filed an application for a drilling unit for the production of coalbed methane, that they may be present and object or offer comments to the formation of the proposed unit, and shall be accompanied with copies of (i) the permit application for the coalbed methane well, (ii) the permit application for the drilling unit, and (iii) the plat of the drilling unit. (1994, c. 24.)

§ 22-21-17. Review of application; hearing; pooling order; spacing; operator; elections; working interests, royalty interests, carried interests, es-crow account for conflicting claims, division order.

(a) Prior to the time fixed for a hearing under subsection (b) of this section, the board shall also set a time and place for a conference between the proposed applicant to operate a coalbed methane drilling unit and all persons identified in the application as having an interest in the coalbed methane or being a claimant if such interests are disputed, who have not entered into a voluntary agreement. At such conference the applicant and such other persons present or represented having an interest in the proposed unit shall be given an opportunity to enter into voluntary agreements for the development of the unit upon reasonable terms and conditions.

No order may be issued by the board as to any unit unless the applicant submits at the hearing a verified statement setting forth the results of the conference. If agreement is reached with all parties to the conference, the board shall find the unit is a voluntary unit and issue an order consistent with such finding.

(b) The review board shall, upon request of a proposed applicant for a drilling unit or upon request of a coal owner or operator, provide a convenient date and time for a hearing on the application for a drilling unit, which hearing date shall be no sooner than thirty-five days nor more than sixty days of the date the request for hearing is made. The review board shall review the application and on the date specified for a hearing shall conduct a public hearing. The review board shall take evidence, making a record thereof, and consider:

(1) The area which may be drained efficiently and economically by the proposed coalbed methane well or wells;

(2) The plan of development of the coal and the need for proper ventilation of any mines or degasification of any affected coal seams;

(3) The nature and character of any coal seam or seams which will be affected by the coalbed methane well or wells;

(4) The surface topography and property lines of the lands underlaid by the coal seams to be included in the unit;

(5) Evidence relevant to the proper boundary of the drilling unit;

(6) The nature and extent of ownership of each coalbed methane owner or claimant and whether conflicting claims exist;

(7) Whether the applicant for the drilling unit proposes to be the operator of the coalbed methane well or wells within the unit; and if so, whether such applicant has a lease or other agreement from the owners or claimants of a majority interest in the proposed drilling unit;

(8) Whether a disagreement exists among the coalbed methane owners or claimants over the designation of the operator for any coalbed methane wells within the unit, and if so, relevant evidence to determine which operator can properly and efficiently develop the coalbed methane within the unit for the benefit of the majority of the coalbed methane owners;

(9) If more than one person is interested in operating a well within the unit, the estimated cost submitted by each such person for drilling, completing, operating and marketing the coalbed methane from any proposed well or wells; and

(10) Any other available geological or scientific data pertaining to the pool which is proposed to be developed.

(c) The review board shall take into account the evidence introduced, comments received and any objections at the hearing, and if satisfied that a drilling unit should not be established, shall enter an order denying the application. If the review board is satisfied that a drilling unit should be established, it shall enter a pooling order establishing a drilling unit. Such pooling order shall:

(1) Establish the boundary of the proposed unit, making such adjustment in the boundary as is just;

(2) Authorize the drilling and operation of a coalbed methane well or wells for production of coalbed methane from the pooled acreage;

(3) Establish minimum distances for any wells in the unit and for other wells which would drain the pooled acreage;

(4) Designate the operator who will be authorized to drill, complete and operate any well or wells in the unit;

(5) Establish a reasonable fee for the operator for operating costs, which shall include routine maintenance of the well and all accounting necessary to pay all expenses, royalties and amounts due working interest owners;

(6) Such other findings and provisions as are appropriate for each order.

(d) The operator designated in such order shall be responsible for drilling, completing, equipping, operating, plugging and abandoning the well, shall market all production therefrom, shall collect all proceeds therefor, and shall distribute such proceeds in accordance with the division order issued by the review board.

(e) Upon issuance of the pooling order, the coalbed methane owners or any lessee of any such owners or any claimants thereto may make one of the following elections within thirty days after issuance of the order:

(1) An election to sell or lease its interest to the operator on such terms as the parties may agree, or if unable to agree, upon such terms as are set forth by the board in its order;

(2) An election to become a working interest owner by participating in the risk and cost of the well; or

(3) An election to participate in the operation of the well as a carried interest owner.

Any entity which does not make an election within said thirty days prescribed herein shall be deemed to have elected to sell or lease under election (1) above.

(f) The working interest in the well shall include (i) the right to participate in decisions regarding expenditures in excess of operating costs, taxes, any royalties in excess of one eighth, and other costs and expenses allowed in the pooling order and (ii) the obligation to pay for all expenditures. The working interest shall exist in (i) all owners who participate in the risk and cost of

drilling and completing the well and (ii) carried interest owners after recoupment provided in subsection (h) of this section. The working interest owners' net revenue share shall be seven eighths of the proceeds of sales of coalbed methane at the wellhead after deduction of operating costs, taxes, any royalties in excess of one eighth, and other costs and expenses allowed in a pooling order. Unless the working interest owners otherwise agree, the working interest owners shall share in all costs and decisions in proportion to their ownership interest in the unit. If any working interest owner deposits or contributes amounts in the escrow account which exceed actual costs, such owner shall be entitled to a refund; and if amounts deposited or contributed are less than actual costs, such owner shall make a deposit or contribution for the deficiency.

(g) The royalty interest in a well shall include the right to receive one eighth of the gross proceeds resulting from the sale of methane at the wellhead and such interest shall exist in the coalbed methane owners: Provided, That any coalbed methane owner who in good faith has entered a lease or other contract prior to receiving notice of an application to form the drilling unit as provided herein, shall be entitled to such owner's fractional interest in the royalty calculated at a rate provided for in such contract. Each such owner shall be entitled to share in the royalty in proportion to his or her fractional interest in the unit.

(h) Where a coalbed methane owner elects to become a carried interest owner, such owner shall be entitled to his or her proportionate share of the working interest after the other working interest owners have recouped three hundred percent of the reasonable capital costs of the well or wells, including drilling, completing, equipping, plugging and abandoning and any further costs of reworking or other improvements of a capital nature.

(i) Each pooling order issued shall provide for the establishment of an escrow account into which the payment of costs and proceeds attributable to any conflicting interests shall be deposited and held for the interest of the claimants as follows:

(1) Each participating working interest owner, except for the operator, shall deposit in the escrow account its proportionate share of the costs allocable to the ownership interest claimed by such working interest owner.

(2) The operator shall deposit in the escrow account all proceeds attributable to the conflicting interests of any coalbed methane owners who lease, or are deemed to have leased, their interest, plus all proceeds in excess of operational expenses, as allowed in the pooling order, attributable to the conflicting working and carried interest owners.

(j) After each coalbed methane owner has made, or has been deemed to have made, an election under subsection (e) of this section, the review board shall enter a division order which shall set out the net revenue interest of each working interest owner, including each carried interest owner and the royalty interest of each coalbed methane owner. Thereafter payments shall be made to working interest owners, carried interest owners and royalty interest owners in accordance with the division order, except that payments attributable to conflicting claims shall be deposited in the escrow account. The fractional

interest of place.

(k) Upon the parties revised division order and all amendments.

(1) Each owner's share.

(2) Each owner's share after recoupment.

(3) Each owner's share of methane proceeds conflicting with the operator's interest.

(4) The operator's share of each legal interest.

(l) The operator's share of funds.

(m) No interest in the coalbed methane permit area.

§ 22-2

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interest of each owner shall be expressed as a decimal carried to the sixth place.

(k) Upon resolution of conflicting claims either by voluntary agreement of the parties or a final judicial determination, the review board shall enter a revised division order in accordance with such agreement or determination and all amounts in escrow shall be distributed as follows:

(1) Each legally entitled working interest owner shall receive its proportionate share of the proceeds attributable to the conflicting ownership interests;

(2) Each legally entitled carried interest owner shall receive its proportionate share of the proceeds attributable to the conflicting ownership interests, after recoupment of amounts provided in subsection (h) of this section;

(3) Each legally entitled entity leasing, or deemed to have leased, its coalbed methane shall receive a share of the royalty proceeds attributable to the conflicting interests; and

(4) The operator shall receive the costs contributed to the escrow account by each legally entitled participating working interest owner.

(l) The review board shall enact rules for the administration and protection of funds delivered to escrow accounts.

(m) No provision of this section or article shall obviate the requirement that the coal owner's consent and agreement be obtained prior to the issuance of a permit as required under section seven [§ 22-21-7] of this article. (1994, c. 24.)

§ 22-21-18. Operation on drilling units.

All operations including, but not limited to, the commencement, drilling or operation of a well upon a drilling unit for which a pooling order has been entered, are hereby deemed to be operations on each separately owned tract in the drilling unit by the several owners. That portion of the production allocated to a separately owned tract included in a drilling unit is hereby deemed to be produced from that tract. (1994, c. 24.)

§ 22-21-19. Validity of unit agreements.

No agreement between or among coalbed methane operators or owners entered into for the development of coalbed methane or forming drilling units therefor may be held to violate the statutory or common law of this state prohibiting monopolies or acts, arrangements, contracts, combinations or conspiracies in restraint of trade or commerce. (1994, c. 24.)

§ 22-21-20. Spacing.

No coalbed methane well may be drilled closer than one hundred feet of the outside boundary of the coal tract from which coalbed methane is or will be produced or within one thousand six hundred linear feet of the location of an existing well for which a permit application is on file, unless all owners and operators of any affected workable coal seams agree in writing. Affected workable coal seams for purposes of this section shall be those which will be penetrated or those seams more than twenty-eight inches in thickness from

which production is targeted. Spacing shall otherwise be as provided in a pooling order issued by the chief, an order establishing special field rules or an order issued by the review board. (1994, c. 24.)

§ 22-21-21. Dry or abandoned wells.

Any coalbed methane well which is completed as a dry hole or which has not produced coalbed methane in paying quantities for a period of twelve consecutive months shall be presumed to have been abandoned and the operator shall promptly plug the well and reclaim all surface land affected by the well in accordance with the provisions of this article, unless the operator furnishes satisfactory proof to the chief that there is a bona fide future use for such well in accordance with the rules promulgated under article six [§ 22-6-1 et seq.] of this chapter. (1994, c. 24.)

§ 22-21-22. Notice of plugging and reclamation of well; right to take well; objection; plugging order; plugging for minethrough.

(a) Prior to the commencement of plugging operations the operator shall give thirty days' advance notice to the chief and to all coal owners and operators whose names and addresses would be required for a permit application under subdivision (2), subsection (b), section six [§ 22-21-6(b)(2)] of this article as of the date of the notice. Such notice shall set out the number and other identification of the well, a copy of the well plat, the date plugging will commence, and the manner and method of plugging.

(b) Any coal owner or operator whose coal seam is affected by such well shall have the following rights:

(1) To convert the well to a vent hole or otherwise take the well. In such event the chief, upon determination that the coal owner or operator has placed the well under a mining permit, shall release the well operator's bond and the well operator shall be relieved of further responsibility for the well; and

(2) To file comment or objection with the chief, within fifteen days after receipt of notice of intent to plug, with respect to the proposed manner or method of plugging. The chief shall consider any such comment or objection and issue an order specifying the manner and method of plugging and reclamation.

(c) Whenever any coalbed methane well is located in that portion of a coal seam which will be mined within six months, the well operator shall, within sixty days after notice from the coal owner or coal operator that the well is to be mined through, plug the well in such manner that the well can be safely mined through. (1994, c. 24.)

§ 22-21-23. Method of plugging.

All coalbed methane wells shall be plugged in such a manner that any workable coal seam surrounding the well can be safely mined and that the well can be mined through. The chief shall promulgate rules specifying the manner

and method of plugging coalbed methane wells and in doing so, or in entering any order for such plugging and reclamation, shall give special consideration to the ability to mine any affected coal seam safely and the protection of any affected coal seam for future mining. (1994, c. 24.)

§ 22-21-24. Existing mining rights.

Nothing in this article shall be construed to affect the mining and other property rights of any coal owner nor shall any provision of this article be construed to preclude a coal operator from removing support of the surface and any structure or facilities thereon and other strata as such rights may exist in any severance deed or other contract. (1994, c. 24.)

§ 22-21-25. Judicial review; appeal to supreme court of appeals; legal representation for review board.

(a) Any person adversely affected by an order of the chief or review board is entitled to judicial review. All of the pertinent provisions of section four [§ 29A-5-4], article five, chapter twenty-nine-a of this code apply to and govern the judicial review.

(b) The judgment of the circuit court is final unless reversed, vacated or modified on appeal to the supreme court of appeals in accordance with the provisions of section one [§ 29A-6-1], article six, chapter twenty-nine-a of this code.

(c) Legal counsel and services for the chief or review board in all appeal proceedings in any circuit court and the supreme court of appeals shall be provided by the attorney general or his or her assistants and in any circuit court by the prosecuting attorney of the county, all without additional compensation. The chief or review board, with the written approval of the attorney general, may employ special counsel to represent the chief or review board at any appeal proceedings. (1994, c. 24.)

§ 22-21-26. Limitation on actions in trespass.

In any case where title to subsurface minerals has been severed in such a way that title to natural gas underlying such tract and title to coal underlying such tract are in different persons, it shall be an affirmative defense to any action for willful trespass arising from the drilling and commercial production of methane from any coal seam underlying such tract, that the operator of such well permitted, drilled and completed such well under color of title of any instrument, deed, or lease for oil and gas purposes from the gas owner, or an instrument, deed or lease for coal mining purposes from the coal owner. (1994, c. 24.)

§ 22-21-27. Injunctive relief.

(a) Whenever it appears to the chief or review board that any person has been or is violating or is about to violate any provision of this article, any rule

promulgated by the chief or review board, any order or any final decision of the chief or review board, the chief or review board may apply, in the name of the state, to the circuit court of the county in which the violation occurred, is occurring or is about to occur, or to the judge thereof in vacation, for injunctive relief against the person and any other persons who have been, are or are about to be, involved in any practices, acts or omissions, in violation, enjoining the violation or violations. The application may be made and prosecuted to conclusion whether any violation or violations have resulted or may result in prosecution or conviction under the provisions of section six or twenty-eight [§ 22-21-6 or § 22-21-28] of this article.

(b) Upon application by the chief or review board, the circuit courts of this state may by mandatory or prohibitory injunction compel compliance with the provisions of this article, the rules promulgated by the chief or review board and all orders of the chief or review board. The court may issue a temporary injunction in any case pending a decision on the merits of any application filed. Any other section of this code to the contrary notwithstanding, the state may not be required to furnish bond or other undertaking as a prerequisite to obtaining mandatory, prohibitory or temporary injunctive relief under the provisions of this article.

(c) The judgment of the circuit court upon any application permitted by the provisions of this section is final unless reversed, vacated or modified on appeal to the supreme court of appeals.

(d) The chief or review board shall be represented in all such proceedings by the attorney general or his or her assistants and in proceedings in the circuit courts by the prosecuting attorneys of the several counties as well, all without additional compensation. The chief or review board, with the written approval of the attorney general, may employ special counsel to represent the chief or review board in any proceedings.

(e) If the chief or review board refuses or fails to apply for an injunctive relief to enjoin a violation or threatened violation of any provision of this article, any rule promulgated by the chief or review board hereunder or any order or final decision of the chief or review board, within ten days after receipt of a written request to do so by any person who is or will be adversely affected by such violation or threatened violation, the person making such request may apply in his or her own behalf for an injunction to enjoin the violation or threatened violation in any court in which the chief or review board might have brought suit. The chief or review board shall be made a party defendant in the application in addition to the person or persons violating or threatening to violate any provision of this article, any rule promulgated by the chief or review board hereunder or any order of the chief or review board. The application shall proceed and injunctive relief may be granted without bond or other undertaking in the same manner as if the application had been made by the chief or review board. (1994, c. 24.)

§ 22-21-28. Penalties.

(a) Any person who violates any term or condition of a permit issued under this article, and the violation is found by the chief or review board to have

rendered unmineable all or a portion of a workable coal seam, is subject to civil penalties, to be imposed and collected by the chief or review board in an amount not to exceed the reasonably expected net profit lost to the coal owner as a result. All penalties collected shall be transferred to the special reclamation fund as provided by section twenty-nine [§ 22-6-29], article six of this chapter.

(b) Any person who violates any provision of this article, any of the rules promulgated by the chief or review board or any order of the chief or review board other than a violation governed by the provisions of subsection (c) of this section, is guilty of a misdemeanor, and, upon conviction thereof, shall be fined not more than one thousand dollars.

(c) Any person who, with the intention of evading any provision of this article, any of the rules promulgated by the chief or any order of the chief or review board, who makes or causes to be made any false entry or statement in any application or other document permitted or required to be filed under the provisions of this article, shall be guilty of a misdemeanor, and, upon conviction thereof, shall be fined not more than five thousand dollars, or imprisoned in the county jail not more than six months, or both fined and imprisoned.

(d) Any person who knowingly aids or abets any other person in the violation of any provision of this article, any of the rules promulgated hereunder or any order or final decision of the chief or review board or director, shall be subject to the same penalty as that prescribed in this article for the violation by such other person. (1994, c. 24.)

§ 22-21-29. Construction.

This article shall be liberally construed so as to effectuate the declaration of public policy set forth in section one [§ 22-21-1] of this article. (1994, c. 24.)

SCOMM

96:18

MEMORANDUM

State of Alaska

Department of Revenue

TO: Bob Baratko
Director Admin. Services

DATE: Jan 26, 1995

FILE NO:

TELEPHONE NO: (907) 277-5627 ext.265

THRU: John Pilkinton
Director Oil and Gas Audit

SUBJECT: ANS EXPORT BAN FISCAL NOTE

FROM: Chuck Logsdon
Petroleum Economist

Apparently there is some confusion over my response to a question about the value of the ANS Export Ban during my testimony before the Senate Finance committee. As I recall I gave a several part response in which I mentioned that one, albeit very rough, way of making the estimate would be to look at the price difference between ANS at the West and ANS at the Gulf. Currently this spread is about \$.50/bbl or using the rule of thumb of \$130 million in general fund unrestricted revenue for every \$1.00/bbl, this would be \$65 million.

The other thing I stated was that even if the price on the West and Gulf were the same, the transportation cost savings alone would account for \$20 million in additional revenues.

The fiscal note I prepared for SJR 3 estimates benefits of \$80 million and uses current prices and transportation costs. The estimate was arrived at as follows:

ANS Price Before Export Ban Lifted
less Tanker Cost

	Gulf	West
	16.90	16.40
	<u>-3.30</u>	<u>-1.20</u>
Net	13.60	15.20

ANS Price After Export Ban Lifted
less Tanker Cost

	Japan	West
	16.65	16.90
	<u>-1.70</u>	<u>-1.20</u>
	14.95	15.70

Weighted Average Net = 14.96
(85% West, 15% Gulf)

Weighted Average Net = 15.59
(85% West, 15% Japan)

Impact on Wellhead = $15.69 - 14.96 = \$0.63/\text{bbl}$ or Revenue = $130 * .63 = \mathbf{\$81.575 \text{ million}}$

The analysis on the following page breaks the total of \$81.575 million down into the amount accounted for by transportation cost savings component and the amount accounted for by higher sales price.

Transportation Effect

	\$3.30	
less	<u>1.70</u>	
	1.60	gross transport savings /bbl
less	<u>.25</u>	(lower price in Japan than U.S. Gulf since Middle East closer to Japan)
	1.35	net transport savings /bbl
*	<u>.15</u>	
	0.2025	net impact on ANS wellhead (15% shipped to Japan)

Total Transport benefit by the rule of thumb = $130 * .2025 = \$26.325$ million

Price Effect

	\$16.90	after export price
less	<u>16.40</u>	before export price
	0.50	gross increase in sales price
*	<u>.85</u>	
	.425	net impact of higher price on ANS wellhead (85% shipped to West)

Total Price Effect benefit by the rule of thumb = $130 * .425 = \$55.25$ million

Total Price and Transportation Effect = $\$26.325 + \$55.25 = \$81.575$ million

The fiscal note prepared for SJR 3 goes to zero at that point at which our forecast of ANS production declines to the point that there is no longer a surplus of ANS for sale on the West Coast in the second half of FY 1997.

Finally please note that at a minimum, regardless of the price of oil we would achieve a \$26.325 million increase in revenues if the ban were lifted in FY 1996.

FISCAL NOTE**STATE OF ALASKA
1995 LEGISLATIVE SESSION**BILL NO. SJR 3Revision Date: 1/23/95

Dept. Affected: _____

Title: A resolution urging the lifting of the ANS
export ban

BRU: _____

Sponsor: Ellis, Duncan, Kelly, et.al.

Component: _____

Requester: Ellis

COMPONENT SERIAL NO. _____

Expenditures/Revenues

(Thousands of Dollars)

OPERATING EXPENDITURES	FY 96	FY 97	FY 98	FY 99	FY 00	FY 01
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES						
-----------------------------	--	--	--	--	--	--

CHANGE IN REVENUES ()	80,000.0	40,000.0	0.0	0.0	0.0	0.0
-------------------------------	-----------------	-----------------	------------	------------	------------	------------

FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY95) cost: \$ _____

POSITIONS

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

If the export ban were lifted, Alaska North Slope oil (ANS) in excess of U.S. West Coast needs could be shipped to the Far East instead of making the long and costly trip via Panama to the U.S. Gulf Coast. Assuming current prices and transportation costs mandating use of Jones Act tankers, lifting the ban would increase the wellhead value of ANS by over \$.50/bbl and thus increase State taxes and royalties. The window of opportunity to enhance State revenues by lifting the export ban is closing. ANS production is projected to continue to decrease so that the West Coast surplus of ANS is projected to disappear by FY 1997. When the West Coast ANS surplus disappears so will the direct benefit to the state treasury from lifting the export ban.

Prepared by: _____

Division: Oil and Gas Audit DivisionPhone: 277-5627Date: 1/25/95

Approved by Commissioner: _____

Date: _____

Agency: _____

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FISCAL NOTE

STATE OF ALASKA

BILL NO. _____

HJR7

1995 LEGISLATIVE SESSION

Revision Date: Original Dept Affected: Natural Resources
 Title: Opposing the ban on the export of Alaska North BRU: Resource Development
 Slope crude oil; . . . Component: Oil & Gas Development
 Sponsor: Reps. Finkelstein, Navarre, Grussendorf, Brown, B. Davis, Porter
 Requestor: _____ Component Serial No. 439

Expenditures/Revenues		(Thousands of Dollars)				
OPERATING EXPENDITURES	FY96	FY97	FY98	FY99	FY00	FY01
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES ()	0.0	0.0	0.0	0.0	0.0	0.0

FUND SOURCE		(Thousands of Dollars)				
1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY95) cost: \$ None

POSITIONS						
FULL-TIME	0	0	0	0	0	0
PART-TIME	0	0	0	0	0	0
TEMPORARY	0	0	0	0	0	0

ANALYSIS: (Attach a separate page if necessary)

There is no fiscal impact associated with implementation of this resolution.

Prepared by: Jim Eason, Director Phone: 762-2547
 Division: Oil & Gas Date: 20-Jan-95
 Approved by Commissioner: M. Rutherford, Nat. Comm. Date: 1/30/95
 Agency: Natural Resources

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FISCAL NOTE

STATE OF ALASKA
1995 LEGISLATIVE SESSION

BILL NO. HJR7

Revision Date: 1/27/95	Dept. Affected: Revenue
Title: resolution urging the lifting of the ANS export ban	BRU: Revenue Operations
	Component: Oil and Gas Audit
Sponsor: Finkelstein, Grussendorf, Navarre	
Requester: Finkelstein	COMPONENT SERIAL NO. 115

Expenditures/Revenues

(Thousands of Dollars)

OPERATING EXPENDITURES	FY 96	FY 97	FY 98	FY 99	FY 00	FY 01
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES						
-----------------------------	--	--	--	--	--	--

CHANGE IN REVENUES ()	80,000.0	40,000.0	0.0	0.0	0.0	0.0
-------------------------------	-----------------	-----------------	------------	------------	------------	------------

FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

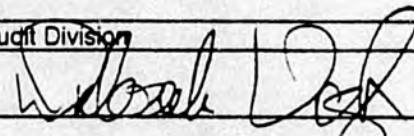
Estimate of any current year (FY95) cost: \$ _____

POSITIONS

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

If the export ban were lifted, Alaska North Slope oil (ANS) in excess of U.S. West Coast needs could be shipped to the Far East instead of making the long and costly trip via Panama to the U.S. Gulf Coast. Assuming current prices and transportation costs mandating use of Jones Act tankers, lifting the ban would increase the wellhead value of ANS by over \$.50/bbl and thus increase State taxes and royalties. The window of opportunity to enhance State revenues by lifting the export ban is closing. ANS production is projected to continue to decrease so that the West Coast surplus of ANS is projected to disappear by FY 1997. When the West Coast ANS surplus disappears so will the direct benefit to the state treasury from lifting the export ban.

Prepared by: John Pilkinton	Phone: 277-5627
Division: Oil and Gas Audit Division	Date: 1/27/95
Approved by: 	Date: 1/27/95
Commissioner: Deborah Vogt	
Agency: Revenue	

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FISCAL NOTE

STATE OF ALASKA

BILL NO. HJR7

1995 LEGISLATIVE SESSION

Revision Date: Original

Dept Affected: Natural Resources

Title: Opposing the ban on the export of Alaska North

BRU: Resource Development

Slope crude oil; . . .

Component: Oil & Gas Development

Sponsor: Reps. Finkelstein, Navarre, Grussendorf, Brown, B. Davis,

Porter

Requestor: _____

Component Serial No. _____

439

Expenditures/Revenues

(Thousands of Dollars)

OPERATING EXPENDITURES	FY96	FY97	FY98	FY99	FY00	FY01
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES ()	0.0	0.0	0.0	0.0	0.0	0.0

FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY95) cost: \$

None

POSITIONS

FULL-TIME	0	0	0	0	0	0
PART-TIME	0	0	0	0	0	0
TEMPORARY	0	0	0	0	0	0

ANALYSIS:

(Attach a separate page if necessary)

There is no fiscal impact associated with implementation of this resolution.

Prepared by: Jim Eason, Director

Division: Oil & Gas

Approved by Commissioner: _____

Agency: _____

Natural Resources

Phone: _____

762-2547

Date: _____

20-Jan-95

Date: _____

1/30/95

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B

HOUSE COMMITTEE REPORT

2/1/95

(7)

Date Referred: January 16, 1995

FURTHER REFERRALS:

Resources
Finance

Date of Committee Action: _____

The HOUSE SPECIAL COMMITTEE ON OIL AND GAS Committee considered:HJR 7

HOUSE JOINT RESOLUTION NO. 7

EXPORT OF ALASKA OIL

Opposing the ban on the export of Alaska North Slope crude oil; endorsing federal legislation to remove restraints on the export of Alaska North Slope oil; requesting the Congress of the United States to pass legislation to permit the export of Alaska North Slope crude oil; and urging the President of the United States to support the legislation to lift the ban on the export of Alaska North Slope crude oil.

recommends it be replaced

with the following committee substitute

CSHJR 7 (O+G)
☐ the same title
☒ a new title
☐ additional referral to _____ Committee☐ attached amendment(s)

ADOPTS: _____ Letter of Intent

ATTACHES NEW FISCAL NOTE(S):

(Dept)

APPROVES PREVIOUS:

(Dept/Date)

☒ fiscal note(s)REV☐ fiscal note(s)☒ zero fiscal note(s)DNR☐ zero fiscal note(s)

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
<u>Don Brice</u> Brice	☒			
<u>W. Williams</u> Williams	☒			
<u>Rokeberg</u> Rokeberg	☒			
<u>Ogan</u> Ogan	☒			
<u>Finkelstein</u> Finkelstein	☒			
<u>B. Davis</u> B. Davis	☒			
<u>G. Davis</u> G. Davis	☒			
	(7)			

CHAIR'S SIGNATURE

Rokeberg

**House Special Committee on Oil & Gas
HJR 7/HJR 19**

Testimony of Beverly Ward
Government Relations, ARCO Alaska, Inc.
January 31, 1995

Mr. Chairman, members of the House Oil and Gas Committee. My name is Beverly Ward. Thank you for the opportunity today to add ARCO's voice to the chorus of those asking that the oil export ban be lifted. We pledge our support to work with the state to win passage of federal legislation eliminating the ban on the export of North Slope oil.

Prior to the 1994 election, we judged passage of legislation lifting the export ban as very unlikely. It now appears passage is possible.

ARCO will not benefit from elimination of the export ban. But because of the potential benefit to the state -- and at the request of the Knowles Administration -- we re-evaluated our long standing neutral position on this issue and decided the time had come to join the state in working to open Pacific Rim markets to Alaska oil.

We will make clear to members of Congress our support for legislation eliminating the export ban. We will also work closely with the Alaska Congressional Delegation, the Legislature and the Knowles Administration on this issue in whatever way is appropriate.

We applaud your efforts through HJR 7 and HJR 19 to lift the oil export ban.

BP Testimony on the Lifting of the
Export Ban on Alaska North Slope Crude
Presented to the House Oil & Gas Committee
January 31, 1995

DRAFT

Good morning, Mr. Chairman and members of the House Oil & Gas Committee. My name is Linda Adamany and on behalf of BP, I am pleased to provide the following testimony to the Alaska State Legislature. This testimony discusses the future of oil production on Alaska's North Slope, and how artificial federal constraints, such as the ban on its export, effect our ability to market it efficiently.

The history of Alaska North Slope oil production is one of remarkable achievement. In the past two decades, the oil industry has invested more than \$50 billion (in today's money terms) in realizing the Alaska North Slope's hydrocarbon potential.

We've nearly doubled the volume of oil we expect to recover from the region through a combination of technological advances and massive capital investment. In 1977, we expected to recover less than 10 billion barrels of oil from a single Alaska North Slope field. Today we're producing oil from a number of fields surrounding Prudhoe Bay. The industry has just produced our 10 billionth barrel of oil, yet we have a similar amount in booked and likely reserves. We postponed Prudhoe's inevitable decline by nearly four years, and today based on the State of Alaska's own forecasts, the North Slope is producing some 600,000 barrels more per day than were projected less than a decade ago.

These achievements are particularly remarkable given the competitive disadvantages of Alaska's North Slope -- disadvantages stemming primarily from harsh climatic conditions, remoteness, and federal restrictions on access to world crude oil markets imposed by the ANS export ban.

But today, the future of this critical domestic resource is in double jeopardy. Production is in decline, and margins that are the lifeblood of the ongoing investments that sustain production are being squeezed as never before by upward pressure on Alaska North Slope costs.

BP, along with our industry partners, have been at the forefront of the industry in doing everything we can to enable Alaska North Slope oil to compete effectively for investment capital in a fiercely competitive world oil market. We've left no stone unturned in searching for new ways to do more for less, and we've stemmed the tide of soaring costs in the late '80s and early '90s.

We've completely retooled our relationships with contractors and field partners. We've reduced our staff levels and overhauled the way we do business within BP. These efforts have reduced our operating costs and enabled us to actually reduce per-barrel operating costs in an atmosphere of declining production without sacrificing safety or our environmental performance.

Because of Alaska's high field development costs, as well as restricted access to world crude oil markets, netbacks on Alaska North Slope production are disproportionately low vis-a-vis those of lower-cost hydrocarbon areas of the world that have unrestricted access to crude oil markets.

Much of the Alaska North Slope production we currently project for the year 2000 depends on investments yet to be made.

More than ever before, the environment dictates that investments be directed to areas offering the highest margins at the lowest risks. With the end of the Cold War and so much of the world now competing for energy investment, returns on those investments have become the prime consideration as companies allocate increasingly scarce capital resources.

The competitiveness of these investments is crucial not only to BP and the Alaskan oil industry, but to the federal government and to the State of Alaska.

The federal government has a significant economic stake in the health of the domestic oil industry.

Many of the individual states also hold large stakes in the health of the domestic industry. Those with significant oil production, like Alaska and California, realize substantial tax and royalty revenues. They also benefit from a significant number of jobs both directly and indirectly linked to oil industry investment.

Much has been said and written about the hydrocarbon potential of Alaska's North Slope. There's a general consensus that the potential significantly exceeds reserves already produced on the company books. This potential comes from existing discoveries, additions and extensions that would be economic, given the availability of investment resources. We at BP concur with this assessment.

It is important to understand that noncompetitive margins have two effects. First, they reduce production of both existing and potential resources and remove cash from the system, making investments more difficult even in potentially profitable opportunities.

It's no longer enough that BP and the rest of the industry, through hard work and innovation, are reducing our costs. In order to maintain the competitiveness of Alaskan investments, it's critical that everyone with a stake in the future of the Alaskan oil industry does his and her part to help ensure its long-term health.

Federal restrictions on our ability to market Alaska North Slope oil where it will generate the highest possible returns hurt producers and the State of Alaska by reducing netbacks on North Slope oil. These restrictions are costly and an unnecessary burden on our ability to compete. Lifting these restrictions will help to restore Alaska's competitiveness for future investment by boosting the wellhead value of ANS crude.

The world has changed dramatically from the days when export restrictions on ANS crude were first imposed ... days of real and perceived supply shortages and an energy crisis mentality. Today, with open markets, improved trade flows, access to new oil and gas provinces and significant discoveries throughout the world, the supply-demand balance has reversed itself.

Restrictions on ANS exports that were based on fears of supply shortages are no longer appropriate. But failure to maintain investment because of loss of competitiveness will not help. Removing the restrictions and providing incentives will maximize domestic production if supply crises should occur in the future.

BP and the Alaskan oil industry will continue to do our part by doing all we can to make Alaska North Slope investments competitive. But we can no longer do it alone.

By directly or indirectly relieving the burden of unnecessary restrictions on our ability to compete, the federal government will not only demonstrate its commitment to do its part to enhance the competitiveness of Alaska North Slope oil, but also to help ensure the long-term health of this critical domestic resource.

BP strongly encourages the State of Alaska to support lifting the ANS export ban.

Thank you for this opportunity to address these important issues.

01/31/95

LEGISLATIVE TELECONFERENCE NETWORK SYSTEM

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PARTICIPANT LIST (ALL PARTICIPANTS)

BY:ANC

TCN:50119

SCHEDULED FOR:01/31/95 10:00 TO 12:00

FOR:ANC

PUBLIC HEARING

HOUSE SPECIAL COMMITTEE ON OIL AND GAS

LOCATION: [REDACTED]

HIP 7

KRITH

BURKE

THE ALLIANCE

TESTIFY

HIP 7

CHICK

LOESON

TESTIFY

Jim Palmer is on-line

& Valdez is also on-line - no testifiers

CS
Amendment to HJR 7

Representative Finkelstein

Page 2, Line 12

Delete "reinvested"

Insert "will be available for reinvestment"

Amendment

P 2, line 16

Delete "reserve additions in Alaska alone could be as large as"

Insert "the additional capital ~~available~~ available could lead to the ~~discovery~~ of up to an additional" *development*

P 2 line 17 After "barrels"

insert "in Alaska"

HOUSE SPECIAL COMMITTEE ON OIL & GAS

VOTING RECORD

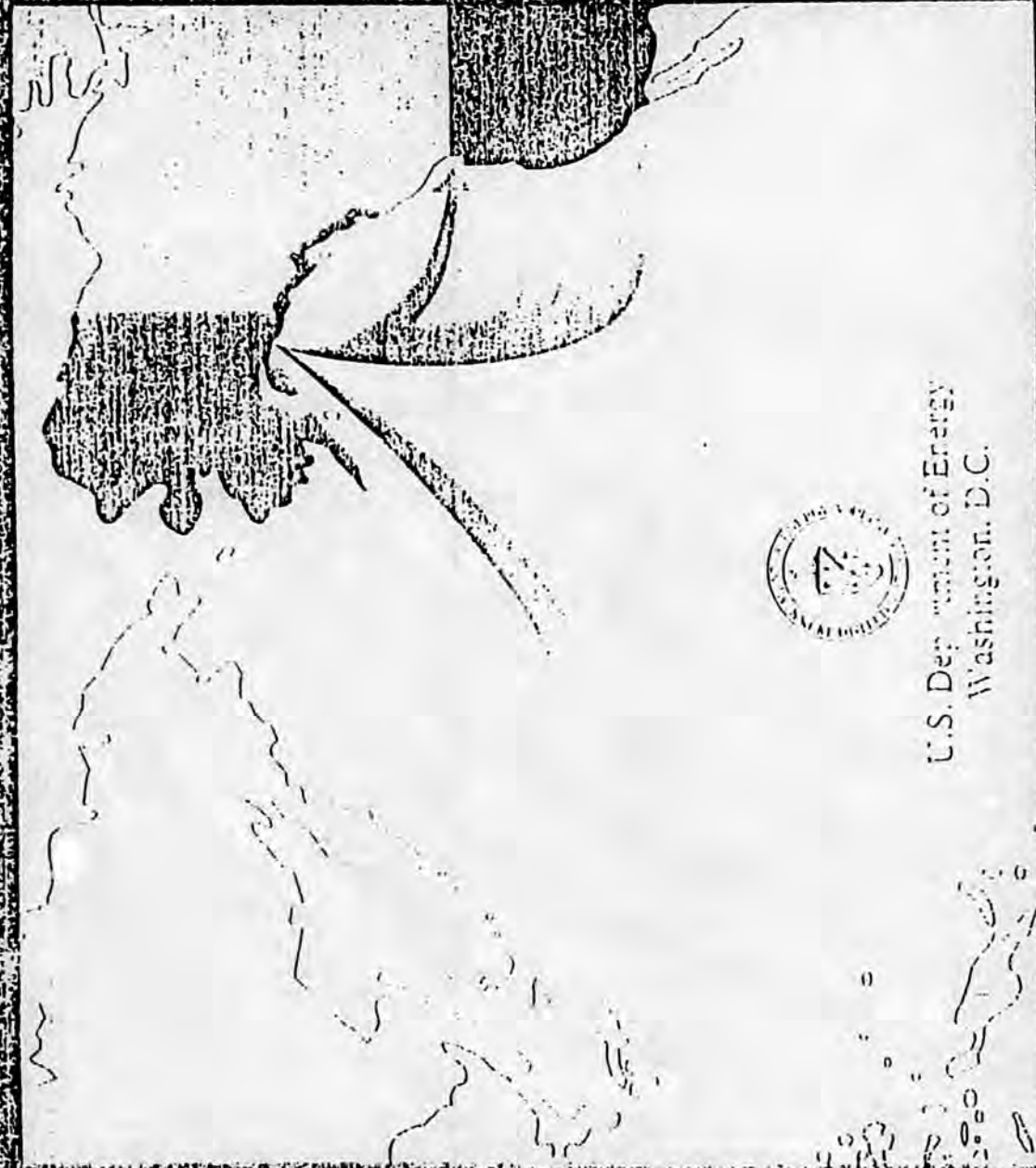
VOTE # 1 2nd Amend.

DATE 1/31/95

	YES	NO	Abstain
Rep. Rokeberg		✓	
Rep. Brice	✓		
Rep. B. Davis	✓		
Rep. G. Davis		✓	
Rep. Finkelstein	✓		
Rep. Ogan		✓	
Rep. Williams		✓	

EXPORTING ALASKAN NORTH SLOPE CRUDE OIL

Benefits and Costs



June 1994

EXPORTING ALASKAN NORTH SLOPE CRUDE OIL

Benefits and Costs



U.S. Department of Energy
Washington, D.C.

June 1994

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PREFACE

The Department of Energy study examines the effects of lifting the current prohibitions against the export of Alaskan North Slope (ANS) crude. The study concludes that permitting exports would benefit the U.S. economy. First, lifting the ban would expand the markets in which ANS oil can be sold, thereby increasing its value. ANS oil producers, the States of California and Alaska, and some of their local governments all would benefit from increased revenues. Permitting exports also would generate new economic activity and employment in California and Alaska. The study concludes that these economic benefits would be achieved without increasing gasoline prices (either in California or in the nation as a whole).

Lifting the export ban could have important implications for U.S. maritime interests. The Merchant Marine Act of 1970 (known as the Jones Act) requires all inter-coastal shipments to be carried on vessels that are U.S.-owned, U.S.-crewed, and U.S.-built. By limiting the shipment of ANS crude to U.S. ports only, the export ban creates jobs for the seafarers and the builders of Jones Act vessels. Because the Jones Act does not apply to exports, however, lifting the ban without also changing U.S. maritime law would jeopardize the jobs associated with the current fleet of Jones Act tankers. Therefore the report analyzes selected economic impacts of several maritime policy alternatives, including:

- o Maintaining current law, which allows foreign tankers to carry oil where export is allowed;
- o Requiring exports of ANS crude to be carried on Jones Act vessels; and
- o Requiring exports of ANS crude to be carried on vessels that are U.S.-owned and U.S.-crewed, but not necessarily U.S.-built.

Under each of these options, lifting the export ban would generate economic benefits.

This report does not fully address the implications of changing U.S. maritime law. For example, the report does not examine whether limiting exports of ANS crude to Jones Act vessels would be consistent with existing U.S. international trade policies and commitments. Because this report does not address these trade-related issues, it makes no attempt to weigh the benefits of lifting the ban against any costs that might result from changes in U.S. maritime law.

Based on a limited review of environmental issues this report finds no plausible evidence of any direct negative environmental impacts from lifting the ban. Further, the Administration is committed to maintaining its current policy against the development of Arctic National Wildlife Refuge (ANWR) and environmentally-sensitive areas of the Outer Continental Shelf (OCS).

EXECUTIVE SUMMARY

OVERVIEW OF FINDINGS

Our examination of the Alaskan North Slope (ANS) crude oil export issue found that there would be a significant number of benefits to the United States from allowing the export of ANS crude. The principal conclusions of this study are:

- o Exporting ANS crude oil would partially relieve the downward pressure on West Coast prices of both ANS and California crude oils. Little, if any, increase in consumer petroleum prices would be likely.
- o Higher crude oil prices would lead to better oil producer profitability, which in turn, would raise investment in domestic oil production.
 - Incremental production in Alaska and California could be as high as 100 to 110 thousand barrels per day (mb/d) by the end of the decade.
 - ⑧ - Reserve additions in Alaska alone could be as large as 200 to 400 million barrels--a size that roughly equates to the known reserves in major North Slope fields such as Point McIntyre, or ~~Endicott~~.
- o Improving conditions for West Coast oil producers would raise royalty revenue for the Federal Government and tax and royalty revenues for the States of Alaska and California. During the years 1994 to 2000:
 - Federal receipts related to royalties and sales of Elk Hills oil production would total between \$99 and \$180 million (1992 \$).
 - Alaska would gain \$700 million to \$1.6 billion in State severance taxes, income taxes, and royalties.
 - California returns from the State share of Federal royalties and State and local taxes would be \$180 to \$230 million.
 - Under the low oil price scenario three-fourths of these benefits accrue between 1994 and 1996.
- o Exporting ANS crude oil would result in a substantial net increase in U.S. employment. In all cases examined, gains related to increases in oil industry investment and State and Federal revenues would be much larger than job losses in the U.S. maritime sector.
 - ⑪ - By 1995, the net increase in U.S. employment would be from 11,000 to 16,000 jobs. By the end of the decade, exporting ANS crude could generate from 10,000 to 25,000 jobs. The range of estimates grows over time due to uncertainty in future oil prices.

- The estimate of the level of net job generation is relatively insensitive to whether ANS oil is exported on foreign-flag, U.S.-flag, or Jones Act tankers (U.S.-constructed and -crewed). Exporting oil in foreign-flag vessels would be the least expensive option, thereby generating higher returns for producers and the State of Alaska. This would lead to the highest level of overall job creation, but also would produce the highest level of job losses in the maritime sector. Exporting ANS crude on Jones Act vessels would lower corporate returns, oil production, and revenues for Alaska, but job losses in the maritime sector would be small. These differences offset each other, thereby eliminating the sensitivity to the method of exportation.¹
- Direct, indirect, and induced employment losses related to the maritime sector could be as high as 3,300 jobs if foreign-flag tankers are employed for exports of ANS crude oil.
- o No significantly negative environmental implications were found.
 - Lifting the ANS export ban would decrease the incentive for opening the Arctic National Wildlife Refuge (ANWR), and would not affect California production from Outer Continental Shelf (OCS) areas.
 - No modifications to the Trans-Alaskan Pipeline System (TAPS) would be required, although incremental production arising from ANS crude exports would extend the economically viable lifetime of the system a few years.
 - Exporting ANS crude probably would decrease crude oil tanker movement in U.S. waters.
 - Greenhouse gas emissions from generating steam to produce additional heavy oil would increase slightly, but this increase would be insignificant.

This report does not fully address the implications of changing U.S. maritime law. For example, the report does not examine whether limiting exports of ANS crude to Jones Act vessels would be consistent with existing U.S. international trade policies and commitments. Because this report does not address these trade-related issues, it makes no attempt to weigh the benefits of lifting the ban against any costs that might result from changes in U.S. maritime law.

The aspects of the study that lead to these findings and the study methodology are summarized in the sections that follow. The body of the report and its appendices provide details.

THE CURRENT SITUATION

The inability to export excess ANS crude oil depresses the open market price of ANS crude on the West Coast. This accounts for part, but not all, of the large differential between the refined value of West Coast crude oil and the low prices refiners offer producers for indigenous crude

¹ If an export restriction only required U.S.-flag ships to be used (i.e., thereby allowing foreign-built vessels into the ANS trade), then the negative employment effects could be greater. This would be the case if the financial attractiveness of ANS exports drew U.S.-flag ships from other international trade that foreign-flag ships then assumed.

oils. The result is that the West Coast generates the largest gross refiner margins in the world. Our preliminary analysis of West Coast petroleum markets concluded that:

- o California refiners today purchase the State's indigenous crude for prices that are between \$0.90 and \$2.50 per barrel lower than its refined value relative to ANS crude oil. This market bias probably would remain even if exporting ANS crude raised the price of all West Coast crudes.
- o The low cost of acquiring West Coast crude oil is not shared with consumers of refined products. West Coast petroleum product prices are, and always have been, at parity with those in other parts of the United States, despite West Coast refiners' low crude oil costs. The result is a gross refiners' margin on the West Coast that averaged \$2.40 per barrel, or 31 percent higher than the U.S. average.²
- o The margin on the West Coast is large enough to accommodate an increase in crude oil prices of \$1.00 to \$2.00 per barrel without hampering the refinery investment needed to meet future environmental standards.

Currently, ANS and California crude oil production still exceeds West Coast requirements, although ANS production has fallen to the point that relatively little is being sold into the Gulf Coast spot market. If ANS production continues to decline sharply, the surplus may evaporate in the next few years. On the other hand, ANS production has shown a resilience that defies pessimistic predictions of some market analysts. The following section describes the study methodology formulated to address this uncertainty.

STUDY METHODOLOGY

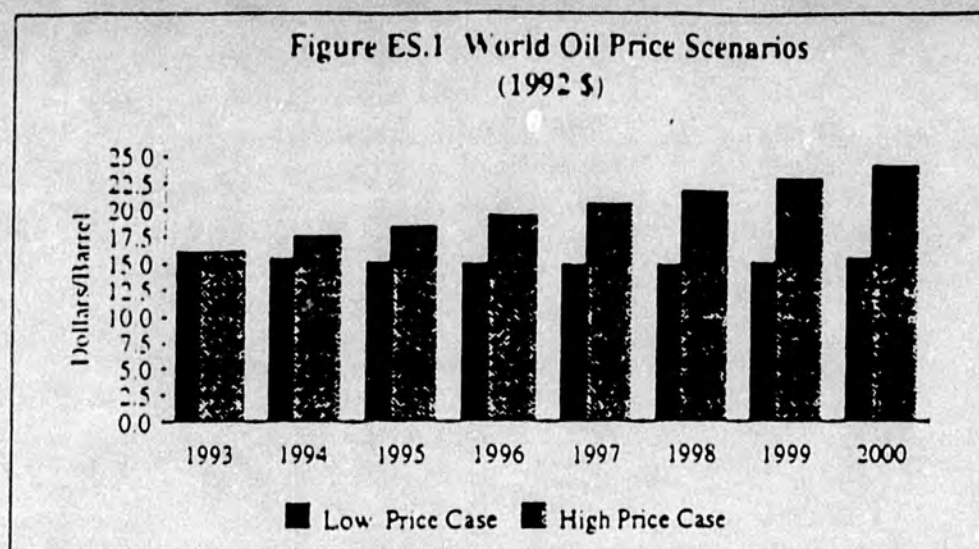
Oil Prices

The study considers two scenarios. In the first, world oil prices would stay constant in real terms through the remainder of the decade. In the second, there would be a \$7.50 per barrel real price growth during 1994 to 2000. These price paths, displayed in Figure ES.1, are the high and low price paths from the Energy Information Administration (EIA) 1994 Annual Energy Outlook-1994 (AE094).

Initially, we thought the low price case would be most favorable to ANS crude oil exports. Accordingly, for consistency, assumptions in the low price case were given export-favorable values. In the high price case, assumptions were given values that tended to reduce the benefits, or raised the costs, of ANS crude oil exports. This approach was favored over a point estimate base case analysis due to the wide range of uncertainty in many areas.

ANS and California crude oil price statistics were examined to determine their historic relationships to world oil prices. This relationship was assumed to continue until the West Coast crude oil supply excess disappears through either a natural decline in domestic production or exports of ANS crude oil.

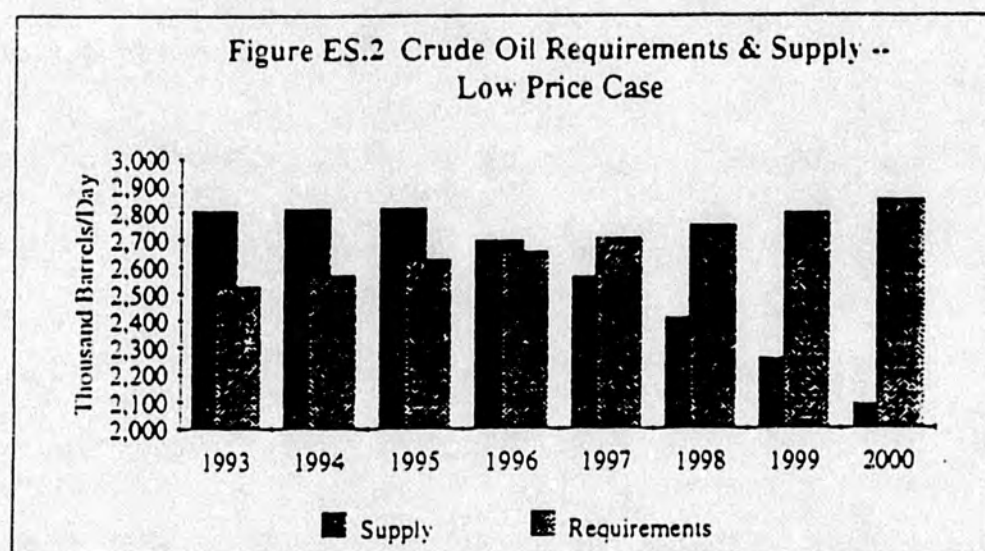
² This understates the regional differences because California is such a large part of the national average refining capacity.



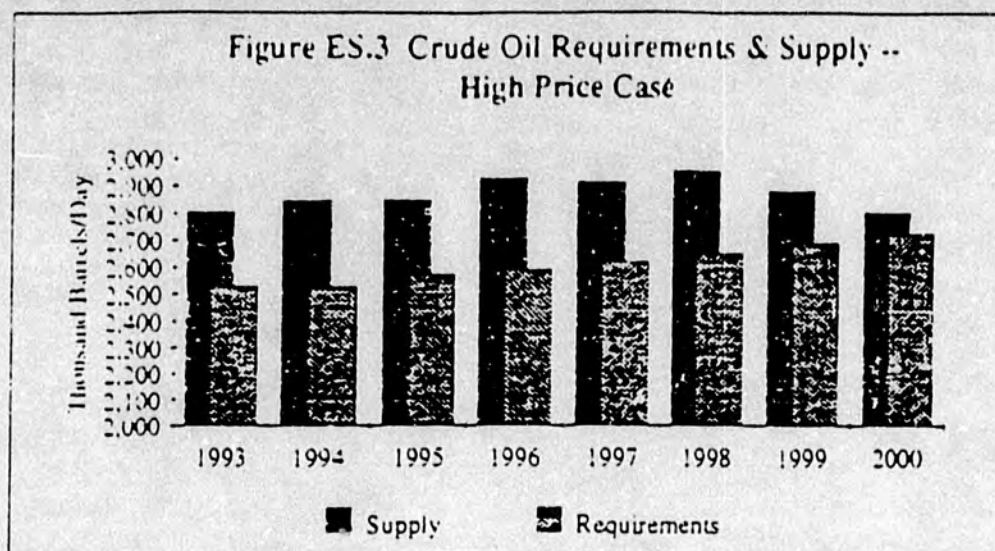
We assumed that when the West Coast crude oil surplus disappears, ANS crude prices would rise to "world market" levels. This is defined as the cost of Arab Light crude oil delivered to California. In the low price case, we added a refining premium determined in our refinery analyses--typically \$0.20 to \$0.35 per barrel. In the high price case, to remain conservative, no refinery premium was added. The value of ANS crude in Japan was similarly determined. California crude oil is assumed to rise also, but only by 80 percent of the increase in ANS prices. Our data analysis showed that this figure is consistent with historic patterns.

Crude Oil Requirements and Supply

Starting with EIA's AEO94, high and low price case petroleum consumption projections for the U.S. West Coast (PADD V)³, we estimated refinery crude requirements. Two domestic crude oil production scenarios were developed that were indicative of high and low price conditions. The results are the supply-demand patterns shown in Figures ES.2 and ES.3.



³ PADD V consists of Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington.



The important features of these two cases are:

- o Under low price conditions, rising petroleum product consumption increases crude oil requirements. At the same time, lower prices depress domestic production so that, by 1997, the PADD V surplus has disappeared.
- o In the high price case, lower consumption and higher oil production perpetuate the surplus throughout the decade.

Export Scenarios and Tanker Requirements

The Jones Act (The Merchant Marine Act of 1920) requires oil transported between U.S. ports to be moved in U.S.-constructed, -built, -owned, and -crewed tankers. In 1993, about 35 Jones Act tankers were used to transport ANS crude oil.⁴

- o In the low price scenario, tanker requirements would fall steadily throughout the decade; by 2000, only 21 tankers would be needed.
- o In the high price case, shipping requirements would actually increase to 38 tankers by 1995 to 1996, then fall to 29 vessels by 2000.

These cases provide the baseline against which three export scenarios were evaluated. The options for export of ANS crude oil were:

- o In the first case, exports would be permitted on world trade, foreign-flag vessels. There would be ample supply of foreign-flag vessels, so costs would be at world levels (that is, the shipping cost would be about \$0.40 per barrel to Japan).

⁴ Several more foreign-flag tankers transport crude oil to the Virgin Islands refinery.

- o In the second case, exports would be restricted to U.S.-flag vessels, but not necessarily to U.S.-constructed vessels. The effect of this constraint would be to increase transportation costs slightly due to the requirement that the vessels meet U.S. crew requirements. Shipping costs to Japan were estimated at about \$0.46 per barrel. Given a permissive reflagging policy, there would again be an ample supply of ships available.
- o In the final case, exporting vessels would be taken from the present Jones Act fleet. This has two main cost implications:
 - There would be a limited number of Jones Act ships, and the principal exporting company would not have direct access to the largest class of tanker (capable of transporting nearly two million barrels of oil per trip). Costs per barrel for exports on tankers that carry 1.3 to 1.4 million barrels per trip would be about 13 percent higher than the U.S.-flag option above.
 - Removing some Jones Act tankers from the domestic ANS trade would raise the average cost of transporting ANS crude domestically by one to three cents per barrel.

The shipping costs used in this study were the result of a detailed, ship-by-ship analyses for each of the years in the 1994 to 2000 period. Transportation cost development took into consideration the fact that the majority of the tonnage in the ANS crude trade is owned or long-term leased by oil producing companies. For these vessels, the appropriate costs to consider are the marginal operating costs. Where third party leasing of Jones Act tankers from non-affiliated ship operators was required in the analysis, incurred costs included recovery of capital investment because market conditions usually support the higher costs for short-term charters.

For the two non-Jones Act shipping cases, three export levels were compared to the baseline, no-export case:

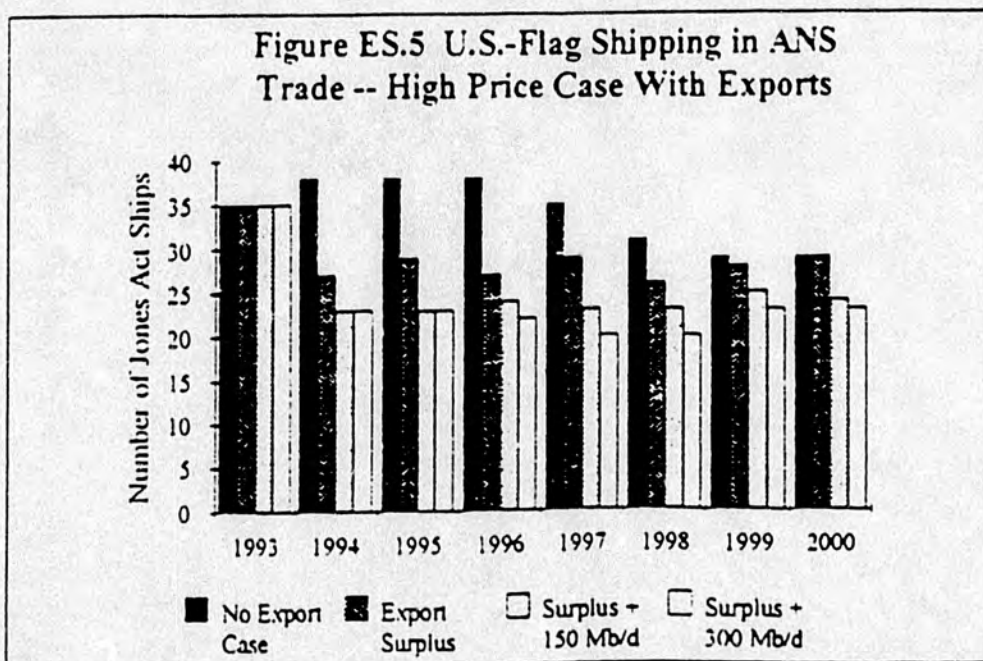
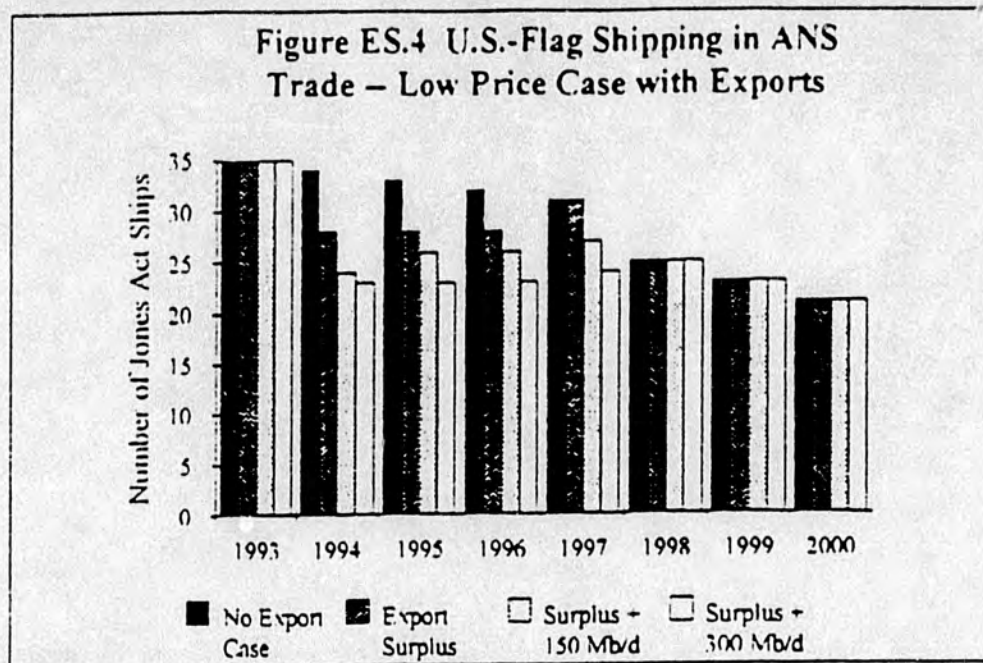
- o Exporting only the PADD V surplus crude oil (i.e., the oil that is now shipped to the Virgin Islands, the Gulf Coast spot market, and to the mid-continent by pipeline).
- o Exporting the surplus and 150 mb/d from PADD V supply as long as the PADD V supply surplus exists.
- o Exporting the PADD V surplus and 300 mb/d from the West Coast supply.

In the Jones Act shipping case, only one scenario was considered. It was assumed that the exporter, due to tanker availability and size limitations, would choose only to export the crude that otherwise would be sold in the Gulf Coast market and 150 mb/d from the West Coast supply. In the near-term, this is more realistic than the above assumptions because shipments to the Virgin Islands and through pipelines to the mid-continent are encumbered by contracts that would be difficult and expensive to abrogate. However, these high-cost shipments incur a significant penalty.

The effects on tanker requirements for the foreign-flag export case are shown in Figures ES.4 and ES.5. It is important to note that:

- o In the low price case, exports only hasten the loss of 7 to 10 tankers that will result from the natural decline in ANS production by 1998.
- o In the high price case, exports reduce the U.S.-flag tanker fleet by 14 to 15 vessels. The remaining fleet size, 20 to 23 vessels, is about the same number as in the low price case. Higher losses for this scenario are caused by the increased shipping requirements associated with a larger, and continuous PADD V surplus.

These Figures underscore the fact that if foreign-flag ships are used for exports, maritime losses are immediate.



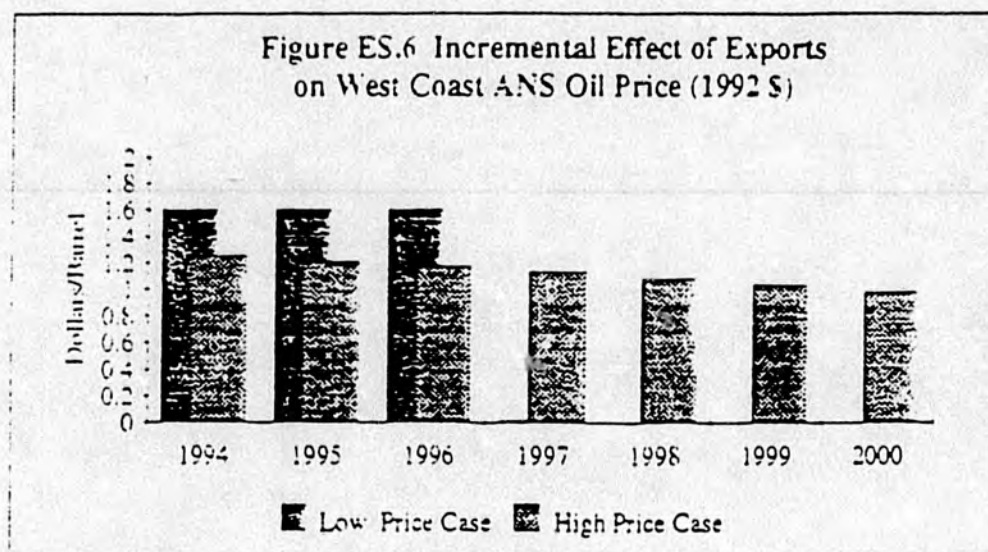
OIL PRODUCTION, REVENUE, AND EMPLOYMENT IMPLICATIONS FOR EXPORTING ANS CRUDE OIL

This section tabulates the quantitative effects of ANS crude exports on oil production, revenues, tanker requirements, and employment. Significant assumptions and observations are included in each subsection.

Results below are for cases where 150 mb/d are exported from PADD V crude oil supplies. The analysis indicated little benefit for exporting only the PADD V excess supply because limiting exports to this surplus amount would have little effect on depressed crude oil prices on the West Coast. Exporting 300 mb/d from the West Coast supply offered little extra benefit over the 150 mb/d case. This is, in part, because the value of exported ANS crude oil would fall in Japan and, at the same time, its marginal value would rise on the West Coast as more crude is exported. These cases are discussed in the main body of the report.

Oil Price Increases

ANS crude price increases on the West Coast are estimated to be in the \$1.60 range for the low price case,⁵ and \$1.20 per barrel in the high price case.⁶ Figure ES.6 shows that the price change effect in the low price case is only attributed to the years in which a PADD V surplus of crude oil exists. In the high price case, the increase, although lower in magnitude, persists through the year 2000.



⁵ Exporting the PADD V surplus and 300 mb/d from the West Coast supply raised ANS prices \$1.83 in the low price case. This was offset, however, by a drop in the value of exported ANS crude as increased exports saturate the market.

⁶ The refining premium is ignored in the high price case to be consistent with the conservative assumptions made in that scenario.

Oil Investment Revenues

Incremental oil revenues are generated by higher sales prices for domestic oil, higher prices gained by sales in the Far East markets, and lower transportation costs. These incremental revenues could be reinvested by oil producers after subtracting taxes and royalties from gross revenues. However, an increased world-level price for ANS crude would not generate incremental investment revenue for all producers. More than half of ANS production and 75 percent of California production is refined by the integrated producer/refiners that own the oil, or trade it for oil that is more conveniently located. The "market price" of this crude is only a transfer price between two divisions of the same company, so it is not assumed to produce potential investment revenue in this study.

Producers' incremental revenue flows, as shown in Table ES.1, are important determinants of the study results. The table shows that:

- o In the low price case, incremental revenues would disappear after 1996 because it is assumed that market prices for ANS and California crude oil would rise to "world levels" even if the ban is not lifted. However, additional investment made between 1994 and 1996 would raise oil production in the later years over current projections. To remain conservative in our estimates of benefits, we ignored the additional investment revenue this production might create (some incremental production may be near marginal costs), but included the Federal and State revenues that the incremental production would generate.
- o In the high price case, lower returns for the 1994 to 1996 period result from the omission of the refining premium for ANS crude oil valuation on the West Coast and in Japan. However, because the surplus continues through the year 2000, incremental revenue generation continues throughout the decade. The incremental revenue, after taxes and royalties are subtracted, is assumed to be used for investment in oil production activities.
- o The U.S.-flag export case creates slightly higher revenues than the foreign-flag export case despite higher shipping costs, due to tax shelter considerations associated with investment cost recovery for company-owned tankers.⁷ Favorable tax treatment is assumed to encourage greater investment and production.
- o In the Jones Act shipping case, high cost domestic shipments to the Virgin Islands and mid-continent are not exported (see earlier description of Jones Act shipping scenario), thereby lowering producer returns.

⁷ If U.S.-flag shipping is employed for the exports, then taxes and royalties would be computed employing full capital recovery (or depreciation) in the cost of shipping. This creates a tax "shelter" that is not present if foreign-flag shipping is chartered from an unaffiliated third party. The tax shelter effect slightly increases production for the U.S.-flag case, and lowers Alaska revenues.

**Table ES.1 Cumulative Oil Company Investment Potential
(Millions of 1992 \$)**

<u>Type of Export Tankers</u>	<u>Low Price Case</u>			<u>High Price Case</u>		
	<u>1994- 1996</u>	<u>1997- 2000</u>	<u>Total</u>	<u>1994- 1996</u>	<u>1997- 2000</u>	<u>Total</u>
Foreign-Flag:						
Alaska	\$455	\$1	\$456	\$334	\$426	\$760
California ^a	158	0	158	122	169	291
Total	613	1	614	456	595	1051
U.S.-Flag:						
Alaska	480	1	481	376	477	853
California ^a	158	0	158	122	169	291
Total	638	1	639	498	646	1144
Jones Act:						
Alaska	425	0	425	317	414	731
California ^a	158	0	158	122	169	291
Total	583	0	583	439	583	1022

^a Only ANS revenues are affected by the type of shipping employed. Therefore, California investment revenues are identical in all three cases.

Oil Production

Production calculations are based on full reinvestment of after-tax revenues in domestic oil production. This is a very reasonable assumption for California independent producers, but one that some might consider questionable for ANS producers. Examination of financial statistics for ANS producers showed little difference between the average of all large integrated companies in the extent to which revenues have been reinvested in the United States. Currently, foreign investment offers a higher rate of return for larger companies than domestic development activities.⁸ If exporting ANS crude oil increased rates of return for ANS production, the tendency would certainly be to increase Alaskan investment over what would otherwise be the case.

In the case of Alaska, producers' after-tax revenues were assumed to be invested in activities that yielded reserve additions at the current rate of \$2.05 per barrel. Data in Table ES.1 imply that reserve additions in the range of 200 to 400 million barrels could be produced by the investment resulting from exports of exports of ANS crude. By comparison, the known reserves remaining (in today's economic conditions) in Prudhoe Bay total about 3.5 billion barrels. Current reserves at Endicott and Point McIntyre, major secondary fields on the North Slope, are 262 and 356 million barrels respectively.⁹

⁸ Performance Profiles of Major Energy Producers-1992, EIA, January 1992.

⁹ Historical and Projected Oil and Gas Consumption, Alaska Department of Natural Resources, February 1994.

Table ES.2 shows the production response potential in the three export cases. Of note is that the total production response is relatively insensitive to the method of shipping chosen. The ANS production response in the high price case is greater than the low price case, but this is offset by lower incremental California production. The California production price elasticity is much higher at low world oil prices than it is for the high price case.

**Table ES.2 Oil Production Potential
(Thousand Barrels Per Day)**

<u>Type of Export Tankers</u>	<u>Low Price Case</u>		<u>High Price Case</u>	
	<u>By 1996</u>	<u>By 2000</u>	<u>By 1996</u>	<u>By 2000</u>
Foreign-Flag:				
Alaska	11	54	8	63
California	18	53	7	33
Total	29	107	15	96
U.S.-Flag:				
Alaska	11	57	9	71
California	18	53	7	33
Total	29	110	16	104
Jones Act:				
Alaska	11	54	8	60
California	18	53	7	33
Total	29	107	15	93

Federal and State Revenue

Table ES.3 presents estimates for State and Federal revenue totals during two time periods: 1994 to 1996 and 1997 to 2000. The primary sources of these revenues are:

- o Alaska--Alaska's 12.5 percent royalty and 15 percent severance tax produce most of the State's returns.
- o California--Revenues come from a share of Federal royalties, State and local income and property taxes, and the State share of a producing field near Long Beach, California.
- o Federal--Receipts are the sum of royalties on California production and sales price increases for the U.S. Department of Energy's (DOE) 50 mb/d production at Elk Hills, California. These revenues are products of the price increase projected for California-produced crude oil; therefore they are not affected by the type of tankers employed to export the oil.

By the end of the decade, incremental production could be financially significant. However, the diversity of sources of revenue, some of which are the product of increased oil prices, implies that returns would begin soon after the ban is lifted.

Table ES.3 Cumulative State and Federal Revenue
(Millions of 1992 \$)

<u>Type of Export Tankers</u>	Low Price Case			High Price Case		
	<u>1994- 1996</u>	<u>1997- 2000</u>	<u>Total</u>	<u>1994- 1996</u>	<u>1997- 2000</u>	<u>Total</u>
Foreign-Flag:						
Alaska	\$667	\$179	\$846	\$610	\$1019	\$1629
California	102	79	181	74	156	230
Federal	96	3	99	72	108	180
U.S.-Flag:						
Alaska	612	189	801	521	942	1463
California	102	79	181	74	156	230
Federal	96	3	99	72	108	180
Jones Act:						
Alaska	562	164	726	450	820	1270
California	102	79	181	74	156	230
Federal	96	3	99	72	108	180

The Effect of ANS Exports on the U.S. Maritime Fleet

Table ES.4 shows the number of tankers and seafarer jobs that would be eliminated if exports were made in foreign-flag tankers. As noted earlier, these losses would be immediate if exports were permitted. However, they are already projected to occur within the next few years as ANS oil production declines, even if the export ban was not lifted.

Table ES.4 Tanker and Seafarer Job Losses Due to Foreign-Flag Exports of ANS Crude Oil^a

	Low Price Case		High Price Case	
	<u>Tankers</u>	<u>Seafarer Jobs</u>	<u>Tankers</u>	<u>Seafarer Jobs</u>
1994	10	632	15	934
1995	7	441	15	934
1996	6	375	14	885
1997	4	238	12	758
1998	0	0	8	472
1999	0	0	4	238
2000	0	0	5	316

^a "Losses" are the year-by-year differences between the no-export case and the case where the PADD V surplus supply of crude oil is exported along with 150 mb/d from PADD V supplies.

Transportation costs for exporting ANS crude in U.S.-flag tankers are only slightly higher than foreign-flag tanker costs. As was shown earlier, there is little difference in financial measures

or oil production if exports were required to be carried on U.S.-flag or Jones Act tankers. This is because most of the U.S.-flag tanker capacity is owned (or leased long-term) by ANS producers, and the out-of-pocket cost to a producer-exporter is just the operating cost of the vessel (fuel, maintenance, and crew costs). This out-of-pocket cost approximates market charter rates for foreign-flag tankers.

If exports were required to be shipped on Jones Act tankers, tanker and job losses of the magnitude shown in Table ES.4 would not occur. Large Jones Act tankers would be employed to export oil, but the distance to Pacific Rim ports is over half again as far as the distance from Valdez to California. In addition, removing larger tankers for export duty would decrease the average size of tankers remaining in the domestic ANS trade, thereby increasing the domestic shipping requirements. These factors offset to a great extent, so that the likely loss in tankers is, at most, one or two small vessels with a total of no more than 118 seafarer jobs.

The employment and ship requirements for the U.S.-flag (not necessarily U.S.-constructed tankers) case is similar to the Jones Act case, but with a caveat. If the financial attractiveness of ANS exports drew U.S.-flag ships from other international trade, and foreign flag ships then took over that foreign trade, larger losses of U.S. crews might result.

Production of Alaskan crude oil could increase by 50 to 70 mb/d by the year 2000 if ANS crude oil was exported. A 120,000 deadweight ton (dwt) tanker can transport 45 mb/d of crude oil from Valdez to Los Angeles, so incremental production could restore the need for one or two medium class domestic tankers--thereby offsetting the losses in the U.S.-flag or Jones Act cases.

While seafarer jobs losses would be partially mitigated if exports are restricted to U.S.-flag shipping, this limitation would not address the concerns of the U.S. ship building industry. Starting in the late 1990s, double hull requirements of the Oil Pollution Act of 1990 (OPA90) will force replacement of, or extensive modification to, most of the tankers in the U.S. fleet (foreign tankers that serve U.S. ports also will have to meet the terms of OPA90). If foreign-built tankers could be reflagged and operated in the ANS oil trade, thereby minimally satisfying the U.S.-flag requirement, then new OPA90-compatible tankers would be built overseas at lower cost. If exports were carried on Jones Act-compatible tankers, this issue would become moot because the Jones Act requires U.S. construction to satisfy OPA90 requirements.

Employment Effects of the Lifting the ANS Export Ban

Lifting the ANS export ban would have a positive net impact on potential U.S. output and employment, even after considering the impacts on the maritime sector. Table ES.5 displays the aggregate results of the employment analysis. For oil related activities:

- o Lifting the ANS ban has the potential to increase direct and indirect employment in oil-related investment, oil production, and through the employment effects of additional State tax revenues for citizens by between 6,500 and 9,700 jobs in 1995 and between 5,400 and 13,900 jobs in 2000 (depending on which mode of export shipping is used). Potential employment increases could be even larger if incremental government revenues were used in whole or in part to increase State and local government employment.

- o Induced employment (i.e., employment due to expenditures by direct and indirect employees) was estimated separately. Induced employment due to increases in oil-related investment, oil production, and State revenues would range from 5,100 to 7,700 in 1995 and 4,700 to 11,500 in 2000.

Table ES.5 Direct, Indirect, and Induced Employment

<u>Type of Export Tankers</u>	<u>Low Price Case</u>		<u>High Price Case</u>	
	<u>1995</u>	<u>2000</u>	<u>1995</u>	<u>2000</u>
Foreign-Flag:				
Oil-Related	17,320	10,574	13,936	24,343
Maritime	(1,559)	0	(3,301)	(1,117)
Net	15,761	10,574	10,635	23,226
U.S.-Flag:				
Oil-Related	16,790	10,889	13,219	25,362
Maritime	(417)	0	(417)	(417)
Net	16,373	10,889	12,802	24,945
Jones Act:				
Oil-Related	15,320	10,122	11,677	23,295
Maritime	(417)	0	(417)	(417)
Net	14,903	10,122	11,260	22,878

The potential increases in direct and indirect employment outside the maritime sector would be significantly larger than the maximum potential adverse impact on maritime employment. The maximum direct and indirect job losses in the maritime sector are estimated to be between 300 and 2,400 jobs in 1995 and between zero to 800 jobs in 2000. In addition, we note the following:

- o If ANS exports are carried on foreign-flag ships, the adverse effect on maritime employment would end when the PADD V surplus disappears--by 1997 in the low price case.
- o If ANS exports are carried on U.S.-flag or Jones Act ships, relaxation of the export ban could actually offset most of the direct and indirect maritime employment losses as more oil is produced and shipped.

The employment impacts were estimated using the Department of Labor's Bureau of Labor Statistics (BLS) employment coefficients. A description of the methodology and sensitivity analysis on various assumptions used in the employment calculations are reported in the main body of the report.

As a quick check on the order of magnitude of these results, we note that increased net oil production in the year 2000 would contribute \$520 to \$560 million (1992 \$) to real GDP in the low price case. Application of a rule of thumb of one job per \$50,000 increase in GDP would result in an estimated 10,400 to 11,200 additional jobs associated with oil-related revenues. These estimates compare favorably with the figures shown in Table ES.5 above.

Finally, ANS exports and the attendant increase in crude oil prices are not likely to cause significant employment losses in the refining sector of the economy. Refinery capacity in the United States fluctuates with petroleum product consumption, not marginal refining economics. Refineries do indeed go out of business, but if product consumption dictates, the same refineries often reopen under new management.¹⁰ Despite dire predications of impending increases in product imports due to deteriorating refinery margins, petroleum product imports to the United States have remained less than 10 percent of petroleum supply for 20 years. In the last five years, imports have fallen to five percent of U.S. petroleum supply.

EFFECT OF ANS CRUDE OIL EXPORTS ON PETROLEUM PRICES

There are four primary reasons why we believe that refined product price increases would be minimal or non-existent if crude oil market prices on the West Coast increase in response to ANS crude oil exports:

- o First, West Coast gasoline and diesel fuel prices always have been at or above world market levels. This opens the West Coast to outside competition if prices rise much farther.
 - Our examination of the Pacific Rim refined product market shows that a price increase of a few cents per gallon for gasoline, diesel, or jet fuel in California would make Pacific Rim supplies financially viable.
 - A statistical analysis of the last six years of monthly crude oil and refined product prices indicates that California gasoline price movements correlate much more strongly with Gulf Coast (Texas) gasoline prices than they do with California refiners' crude oil supply costs. This implies that market arbitrage keeps West Coast product prices in line with outside sources even though little product actually moves between the West Coast and other regions.
- o Second, integrated refiner/producers with West Coast refineries own about 60 percent of the crude production in PADD V.¹¹ Although market prices for West Coast crude supplies would rise, this is irrelevant for a refiner that processes crude from its own production assets: that refiner's cost of supply remains the cost of crude oil production and transportation. While it might seem that the refiner is forgoing an opportunity to sell ANS crude oil at a higher price, that is not the case. Doing so would require purchase of replacement crude oil at market prices to support the refiner's refined product distribution requirements. In summary, if crude oil market prices rise, there is a much smaller incurred cost than seems to be the case at first glance.
- o Third, the history of West Coast product marketing is one of aggressive competition in product markets, despite their non-competitive behavior on the upstream side of the industry. This suggests that major refiners in PADD V that their own crude oil production may restrain their product price increases to acquire market share from their competitors.

¹⁰ One large West Coast independent refiner, for example, as part of its ANS crude oil supply agreement, must offer its refinery for sale to its crude oil supplier if its financial condition dictates a sale or closing.

¹¹ Over 50 percent of ANS crude production and 75 percent of California crude production.

- o Finally, our refinery analysis showed that the manufacturing cost increase of light petroleum products is smaller than would be expected from a simple allocation of crude oil price increases. This is because the imported crudes that would replace ANS oil tends to be more compatible with West Coast product demand.¹²

In summary, the West Coast consumer is unlikely to notice any change in product prices caused by export of ANS crude oil.

ENVIRONMENTAL IMPLICATIONS

Protection of the environment is a primary consideration in all energy policy decisions of the Clinton Administration. Our review found no plausible evidence of any direct negative environmental impact from lifting the ANS export ban. This conclusion reflects, in part, the historical decline in California production levels and the structure of California's environmental regulations. When indirect effects are considered, it appears that the market response to removing the ANS export ban could result in a production and transportation structure that is environmentally preferable to the status quo in certain respects. Specific findings follow:

- o ANS and ANWR--The Administration, with strong support in Congress, firmly opposes exploration, development, or production activities in ANWR. Lifting the export ban may, in fact, weaken the case for opening ANWR, because it would be difficult politically to argue for opening ANWR while exporting ANS crude oil.

To a degree, lifting the ban on ANS crude oil exports would offset future pressure to open ANWR. Company reinvestment of incremental revenues derived from lifting the ban could expand recoverable reserves within currently developed areas on the North Slope by 200 to 350 million barrels between 1995 and 2000. This amount equates in magnitude to a 10 percent extension of remaining reserves at Prudhoe Bay, and would reduce the need to develop ANWR.

- o The ANS Export Ban and TAPS--Lifting the export ban will not require expansion of TAPS and related infrastructure due to the natural decline in North Slope field productivity. The modest increase from a declining baseline production level that could result from lifting the export ban would not restore production to current levels, much less increase them. Environmental emissions associated with the operation of TAPS would also decline over time as throughput decreases from design capacity. Finally, incremental production associated with lifting the ANS export ban would extend the economically viable lifetime of TAPS by no more than two or three years.
- o Tanker Operations--Lifting the export ban will reduce overall tanker movements in U.S. waters. This is because increased onshore California production will decrease the need for waterborne movements of crude to the State. ANS crude oil exports may also reduce oil transportation risks by eliminating movement of ANS crude oil to the Gulf Coast that involve multiple loading and unloading operations. Eliminating the ANS export ban does

¹² To some extent, this is happening now. Imports of Oman crude in California are rising because it produces products that are more compatible with California's new diesel specifications.

not change requirements of OPA90 on either foreign or domestic tankers loading or discharging oil in U.S. ports.

o California Air Quality Considerations--Our specific findings in this area are:

- Lifting the export ban should not affect the level of emissions at California refineries because emissions in California non-attainment areas are generally subject to absolute caps, often including a reduction schedule as dictated by California regulations. In addition, the absolute amount of crude input required to meet California product needs would decline slightly in the near term, as imported oil that provides a higher proportion of gasoline substitutes for ANS crude oil.
- California heavy oil producers are subject to strict permitting constraints and offset requirements that would prevent any increase in overall emissions as production activity rises.
- Imported oil that would substitute for ANS crude exports would have a lower sulfur content than ANS crude, thereby lowering the average sulfur content of the crude processed in California refineries. This would reduce sulfur-related emissions from refineries and, all other things being equal, from combustion of fuels produced in California refineries.

o California Offshore Areas--California offshore activities are limited by drilling moratoria in effect in most areas, and by limitations relating to the siting of onshore facilities imposed by state, county, and local governments. Offshore development is so encumbered by high capital costs that the small oil price increases proposed by this study would not change project economics measurably, and therefore, would not lead to increased offshore development.

o Greenhouse Gas Emissions--Lifting the export ban would have no appreciable impact on greenhouse gas emissions. We estimate that annual emissions from thermal enhanced oil recovery (TEOR) activities would increase by less than one-quarter of a million metric tons (i.e., less than two one-hundredths of one percent of 1990 U.S. carbon emissions). The net effect would be even lower if the benefits stemming from cogeneration of electricity at natural gas-fueled TEOR sites is taken into account.

o Product Price Increases--As discussed above, we doubt that petroleum product prices would rise following removal of the export ban. If they do, higher prices will spur conservation, reducing both greenhouse and smog-causing emissions.

TRADE EFFECTS

Exporting ANS crude to Japan and other Pacific Rim countries could improve the U.S. trade balance with those countries, but the net national trade benefit would likely be small. Considering the low price case as an example, if PADD V's surplus ANS crude supply was exported along with an additional 150 mb/d from PADD V supply, about \$2.0 billion in annual exports would be generated. Since, in the near term, crude oil must be imported to replace

exports, the effect would be to shift a portion of the U.S. trade deficit away from Japan and toward another country such as Saudi Arabia, Mexico, or Indonesia.

Our analysis shows that incremental domestic oil production would appear to offset these imports partially. However, the response would be slow to develop. For example, it would take several years to generate even half the amount of ANS crude removed from PADD V. Therefore, in the short term, the net trade effects probably would be neutral.

DEPARTMENT OF DEFENSE CONSIDERATIONS

The investment planning conducted by DoD is based on fleet projections for the year 2000. The fleet projections that have been provided to DoD by the U.S. Maritime Administration (MARAD) have already taken into account reductions in the tanker fleet that are similar in magnitude to those projected under either of the price assumptions covered in this paper. Therefore, regardless of the price assumptions, the proposed changes to policies on ANS crude export would have no impact on DoD operations.

DoD and the Department of Transportation (DOT) are currently working on estimates of manpower requirements for the Ready Reserve Force (RRF). This study will determine whether there will be an adequate number of civil mariners to staff the RRF in wartime. The DoD determination of that adequacy depends on the implementation of DOT's new Maritime Security Program and the future size of the RRF. However, determination of whether there will or will not be a shortage is several months away. Because of the higher cost associated with Jones Act shipping, DoD would not, however, argue for a requirement that exports be carried on Jones Act ships.

CHAPTER 1 BACKGROUND

THE CLINTON ADMINISTRATION'S DOMESTIC NATURAL GAS AND OIL INITIATIVE

Throughout the summer and fall of 1993, the U.S. Department of Energy (DOE) conducted an intensive effort to identify actions that the Federal Government could take to improve conditions in the natural gas and oil industries of the United States. On December 9, 1993, President Clinton released the Domestic Natural Gas and Oil Initiative--a compendium of actions aimed at boosting markets for domestic natural gas and oil, while developing a long-term strategy to address America's dependence on insecure sources of foreign oil. One of the action items was a review of the prohibition on exporting Alaskan North Slope (ANS) crude oil.

A BRIEF REVIEW OF THE ANS EXPORT BAN HISTORY

The Trans-Alaska Pipeline Authorization Act of 1973 permitted building a pipeline from the North Slope producing fields to Valdez, but, through an amendment to Section 28 of the Mineral Leasing Act, placed strict prohibitions on exporting the oil.

Much of the public opposition to the pipeline centered around environmental concerns about robust Alaskan oil development. However, as with most major public issues, there were many agendas. For example:

- o In the debate on the Trans-Alaskan Pipeline authorization bill, organized labor switched sides and lobbied for the pipeline. The quid pro quo was that the oil would be statutorily prevented from being exported.¹³ In that case, ANS crude would have to be carried on Jones Act (U.S.-constructed and -crewed) tankers--a substantial mission for the U.S. maritime fleet.
- o Others in Congress, who were concerned about U.S. oil shortages following the 1973 Arab oil embargo, thought that the ANS pipeline would make it easy to export U.S. reserves, thereby increasing U.S. vulnerability to a supply disruption.

The final result of these concerns was that the Act narrowly passed (then Vice President Spiro Agnew cast the tie-breaking vote), with strict export prohibitions included. Subsequent legislation, the 1977 amendments to the Export Administration Act of 1969 (EAA) and the Energy Policy and Conservation Act of 1975, strengthened the export restrictions. The Export Administration Act of 1979, which replaced the 1969 EAA, essentially prohibits the export of ANS crude oil during non-emergency periods, except for limited exports to Canada.

¹³ From testimony of Maritime Union officials in public meetings conducted by DOE in March 1994.

The ANS export ban has been studied frequently. These studies have consistently shown net benefits from lifting the export ban. For example:

- o In 1985, a study was required by section 120(a) of the EAA. It was an interagency effort led by the Department of Commerce. Further "review" of the issue was recommended.
- o In 1990, the General Accounting Office, with the help of DOE's Energy Information Administration (EIA), studied the issue at the request of Congressman Philip Sharp.
- o ANS exports were considered, but were not part of either the 1987 DOE Energy Security Study or the Bush Administration's National Energy Strategy.

Both the Reagan and Bush Administrations were committed to opening the Arctic National Wildlife Refuge (ANWR) to oil exploration. Lifting the export ban would have made that politically more difficult.

In 1992, the State of Alaska sued the Federal Government, challenging the constitutionality of the ban and claiming that it cost the State billions of dollars in lost tax and royalty revenues. A Federal court upheld the ban on March 1, 1994, and Alaska plans to appeal.

Ironically, President Bush came close to signing an Executive Order lifting the ban late in 1992 at the urging of Alaska's governor. However, he was prevented from doing so by the Department of Justice's defense against the Alaska lawsuits. The Justice Department had taken the position that other statutes embraced the language of the EAA on the subject, so the ban was legally still in place even though the EAA had expired.

The history of debate on the ban is robust, and sometimes quite colorful, but it cannot be fully covered here. Nevertheless, this brief overview serves to demonstrate that this has been a highly charged emotional issue for years. The congressional and public correspondence that DOE has received since announcing the study shows that it remains so today.

WINNERS AND LOSERS

Perhaps the most vocal group advocating lifting the ANS export ban today are the California independent crude oil producers. These companies, many of which produce only a few hundred barrels of oil per day (some less), argue that their prices are abnormally depressed by several artificial factors, the most significant of which is the West Coast's "over-supply" of ANS crude oil. These companies are the classic economic price-takers. That is, because major refiners own and control the oil pipelines from the oil fields to refineries, the producers can only accept what the refiners offer. Even though most pipelines do not operate as common carriers, independent producers argue that if the ban was lifted, refiners would be forced to bid for their crude oil, and its price would rise. Refiners disagree.

Allowing export of ANS crude oil has positive and negative aspects. On the positive side, the oil may have a higher market value in Pacific Rim countries that are less gasoline-oriented than the U.S. West Coast. If this is the case, opening West Coast markets to world oil trade should raise U.S. market prices for Alaskan oil. A similar effect might be seen in California. The result

would be increased State and Federal royalty and tax revenues, and an improved financial climate for beleaguered independent West Coast oil producers.

On the negative side, higher California crude oil prices would raise costs for West Coast independent refiners. Because it is unlikely that the increased costs could be reflected in higher petroleum product prices, refining profits could decline. In addition, exporting ANS crude oil in foreign-flag tankers would accelerate the decline in the requirement for U.S. maritime tankers on the West Coast.

Eight years have passed since the Executive Branch of the Federal Government last comprehensively evaluated this important trade and energy issue. At the time the 1985 Commerce Department study was performed, more than 850 thousand barrels per day (mb/d) of ANS oil moved past California to eastern U.S. destinations. The high cost of this transportation in U.S.-flag vessels suggested that there were large efficiency-related returns for permitting ANS crude exports to Pacific Rim countries.

Today, the situation is somewhat different. ANS crude production has fallen, and petroleum demand is higher on the West Coast. Combined with lower oil production in California, the result is that less than 300 mb/d of ANS crude is shipped east and little of it enters the Gulf Coast market. As ANS crude production declines in the future, this quantity will fall. This has three implications:

- o First, the demand for U.S.-flag tankers in the Alaskan trade will drop even if the export ban is not lifted.
- o Second, as high-cost ANS oil shipments to the U.S. Gulf of Mexico and Virgin Islands fall to zero, the economic and financial rewards for lifting the ban would seem to lessen. This is because exporting ANS oil will no longer "save" the several dollars per barrel that it costs to move the oil east.
- o Finally, in the last part of this decade, the U.S. West Coast will again be dependent on foreign oil for its incremental supplies. In theory, this will tie the West Coast price structure more closely to Pacific Rim oil markets and could raise prices for incremental supplies.

A market for ANS crude exports might exist even when the West Coast becomes a substantial oil importer. With restraints on exporting removed, some producers might find it financially advantageous to avoid the higher costs of U.S.-flag shipments to the lower 48 States. If ANS crude is valued higher in the fuel oil-oriented economies of Pacific Rim countries than in the gasoline-oriented United States, the attractiveness of exporting ANS crude might increase further. This reasoning suggested that the ANS crude export study should have two major components:

- o One is to estimate, under reasonable scenario assumptions, the amount of ANS oil that might be exported and its price. Reaching that objective requires estimation of a number of parameters including ANS crude production, California oil production, petroleum demand, shipping costs, and so on.

o The second set of tasks involved assessing the impact of exports on:

- State and Federal revenues;
- employment (California and national);
- the West Coast refining industry;
- the U.S. shipping industry; and
- incremental oil production resulting from higher oil prices and additional investment by oil producers.

The following sections describe how this analysis was structured, and the results that were obtained.

CHAPTER 2 PRELIMINARY ANALYSES

CALIFORNIA CRUDE OIL BRINGS RELATIVELY LOW PRICES

Many analysts and economists have examined California crude oil prices and attempted to explain why they are so low. It is true that California crude oils are predominantly heavy and viscous (hard to refine, some say), but California is dominated by large, complex refineries that can break the crude oil down into very good yields of light products. When simple quality adjustment factors that apply in the U.S. Gulf Coast markets, or, for that matter, throughout the world, are applied to California crude oils, they generate prices estimates that are much higher than what the California refiners offer.

This problem is relevant to the ANS export issue because it helps characterize the market conditions that plague West Coast producers. It also suggests that removing the ban may help correct some, but not all, of the problems faced by independent producers in California. Table 2.1 shows that, even considering the price depressing effects of the ANS export ban, California wellhead prices are low compared to prices in other areas.

Table 2.1 Undervaluation of California Heavy Crude Oil (1992 \$)

<u>Crude Oil Type¹⁴</u>	Single Complex Refinery Analysis			
	<u>Refined Value</u>	<u>Net to Wellhead</u>	<u>Typical Posted Price</u>	<u>Under-Valuation</u>
Alaskan North Slope	\$16.16	-	-	-
Kern River (13 Degree API)	15.33	\$14.33	\$11.80	\$2.53
Wilmington (17 Degree API)	15.67	15.07	12.44	2.63
World Oil Model (Multi-Refinery)				
Alaskan North Slope	13.20	-	-	-
Kern River (13 Degree API)	11.53	10.53	9.63	0.90
Wilmington (17 Degree API)	12.52	11.92	10.16	1.76

Table 2.1 displays the refined values of two typical California heavy crude oils relative to the refined value of ANS crude (the absolute price of ANS is unimportant; it is the relative value that is significant). Starting with the refined values we adjusted to wellhead values and compared this to prices typical of those that refiners offer.

- o Refined values of the two heavy crudes were adjusted to the wellhead by subtracting \$1.00 for Kern River and \$0.60 for Wilmington crudes. These transportation costs are consistent with the only common carrier pipeline in the State (ARCO's Line 63).

¹⁴ Kern River Crude Oil is one of many San Joaquin Valley heavy crude oils. Wilmington is produced near Los Angeles.

- c) "Typical Posted Price" was calculated using the historic analysis of posted price relationships between California and ANS crudes, included as Appendix B. There it is shown that San Joaquin Valley (SJV) 13 degree API heavy crudes, on average, have been posted at about 73 percent of the price of ANS spot prices. The factor for Wilmington crude is 77 percent.

It is interesting to note that the difference in refined value between the two heavy crude oils and ANS crude oil ranges between 5 and 11 cents per degree API. This price difference is even lower than the 10 to 15 cents employed to adjust lighter crudes in U.S. Gulf Coast markets. The California contradiction, however, is that when "typical" wellhead posted prices are compared to the refinery values netted to the wellhead (by subtracting transportation costs as in Table 2.1), the posted prices are found to be significantly lower than the crude oil's true value to refiners. The single refinery model analysis indicates the undervaluation may be in the range of \$2.50 to \$2.60 per barrel.

The World Oil Refining Logistic Demand (WORLD) Model offers a picture similar to the single complex refinery model, but that the amount of undervaluation may be only \$0.90 to \$1.76 per barrel.¹⁵

We examined the effect of exporting ANS crude oil on the relative values of ANS and California heavy crudes, and found that exports generally helped close the gap, particularly in the WORLD Model cases. However, the degree of structural bias imposed in California between the refinery and the wellhead is not likely to be fully addressed by exporting ANS crude oil.

PADD V CONSUMER PRICES AND CRUDE OIL COSTS¹⁶

This section explores the price relationships between PADD V crude oil and petroleum prices. In doing so, it addresses constraints that would mitigate a product price increase on the West Coast if prices for domestic crude oil rise.

PADD V Petroleum Product Price are at World Levels

Some have argued that, if the ANS export ban is lifted, crude oil prices would rise on the West Coast and consumers would pay the cost of removing the ban. But Table 2.2 shows that West Coast product prices are, and always have been, at parity with other parts of the U.S., despite West Coast refiners' low crude oil costs. Therefore, West Coast refiners do not have much room to raise prices further without opening their markets to domestic supplies from the U.S. Gulf Coast or foreign imports.

¹⁵ On closer reflection, we concluded that modeling calibration problems that were not solvable within the time available, minimized the apparent undervaluation of California crudes. We were not able to model the situation wherein a producer of ANS crude oil without West Coast refineries would send ANS crude oil to the U.S. Gulf, mid-continent, or Virgin Islands at an apparent loss. In reality, one producer does this (although the "loss" is simply lower production profits) to prevent West Coast ANS crude prices from collapsing. Our quick solution was to constrain the WORLD Model's inter-region shipments. However, this produced abnormally low marginal values for California crudes, thereby magnifying the differences between estimates of their refined values and that of ANS crude oil.

¹⁶ PADD V consists of Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington.

Table 2.2 shows volume-weighted petroleum product prices, crude oil costs, and their differences--termed gross margins--for PADD V and the United States as a whole.¹⁷ On average over the 1988 to 1993 period, the gross margin in California is \$2.40 higher than the national average.¹⁸ While gross margins should not be confused with profit margins, the difference in gross margins suggests that there is ample room for an increase in crude oil prices without significantly affecting West Coast consumer prices.

Table 2.2 Petroleum Product Prices and Refiner Gross Margins (1992 \$)

<u>Weighted Averages</u>	<u>1988</u>	<u>1989</u>	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>
U.S. Products	\$21.88	\$25.09	\$30.64	\$26.95	\$26.05	\$24.58
PADD V Products	22.69	25.59	30.97	25.72	27.49	26.81
U.S. Crude Costs	14.67	17.97	22.22	19.06	18.43	16.41
PADD V Crude Cost	12.86	16.30	20.46	16.23	16.32	14.41
<u>Gross Margins</u>						
U.S. Average	7.21	7.12	8.42	7.89	7.62	8.17
PADD V Average	9.82	9.29	10.51	9.49	11.17	12.39

Refining Expense and Gross Margins

A significant increase in the cost of crude oil might not be affordable for refiners if current or future expenses of operation are abnormally high on the West Coast. For example:

- o Gross margins in PADD V might be high because it is so expensive to refine California's heavy crude compared to the light sweet crudes available in PADD III.¹⁹
- o If crude oil costs rise, PADD V refiners might not be able to afford the modifications necessary to meet the environmental standards posed by the Clean Air Act Amendments of 1990 and other statutes.

Even in the extreme, the first argument does not go far to explain the difference in margins. The primary expense associated with California heavy crudes is breaking down the residuum in cokers. While a similar expense exists at U.S. Gulf Coast refineries, about 60 percent of each barrel of typical California SJV heavy crudes must be coked versus about half that for crudes

¹⁷ The primary source of prices is refiners' wholesale prices and sales volumes reported in EIA's Petroleum Marketing Annual for various years. Crude oil prices were obtained there also, with the exception of the imported crude prices and those for ANS oil. The latter is an average of ANS spot prices in Los Angeles, and the former is simply the ANS crude price plus \$1.00 per barrel, a price typical of landed Indonesian crude oil.

¹⁸ Realize that this comparison understates the difference between PADD V and the U.S. Gulf or East Coast refining areas because PADD V is part of the national average.

¹⁹ PADD III consists of Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas.

characteristic of U.S. Gulf refinery inputs. At coker costs of \$1.75 per residuum barrel processed,²⁰ the cost difference amounts to \$0.51 per crude oil barrel.

This comparison overstates the cost difference for PADD V because the "average" barrel refined there is lighter than 13 degree API SJV heavy crude. In fact, the 1992 average API gravity of crude inputs in PADD V was about 25 degrees, versus 32.4 degrees for PADD III refineries and 31.3 degrees for the nation. Furthermore, the average sulfur content for crude oil inputs in PADD V was 1.19 percent versus 1.23 percent for PADD III and 1.16 percent for the nation. In summary, higher heavy oil processing cost in PADD V probably only account for about \$0.25 to \$0.50 per barrel of the higher gross margin.

Regarding meeting future environmental standards, the National Petroleum Council's recent report on refining suggests that the national average cost over the next few years will be in the range of \$1.00 per barrel of refinery crude oil capacity. Built into these figures was an "industry judgement" factor that it is 40 percent more expensive to perform the same construction and operation in California than in the Gulf Coast area--the cheapest area (the PADD II factor was 20 percent).²¹ Since this logic suggests that the national average cost of adding refinery capacity would be somewhat greater than that on the Gulf Coast, the additional environmental compliance expense for PADD V could be in the range of \$0.20 to \$0.40 per barrel.

Even if these two arguments are both true, then, taken together they amount to less than \$1.00 per barrel, and may be as low as half that amount. The appropriate conclusion is that the gross margin differential between PADD V and the nation as a whole could amply support an increase in crude oil prices of \$1.50 to \$2.00 per barrel without necessarily causing an increase in consumer prices.

Inter-Market Arbitrage and Consumer Prices

The U.S. West Coast is geographically remote from the active Gulf Coast markets and those of the Pacific Rim. Yet, since California product prices are already at, or above, the other markets, there would seem to be limits to which prices could rise. To address this issue, we compared spot prices in California and Washington State to Singapore spot product plus transportation to the West Coast. We also examined California retail gasoline prices to assess the effect of changes in California crude oil costs. These analyses are detailed in Appendix G and summarized below.

²⁰ This is the sum of fixed and variable costs as set forth in Appendix III of the August 1993 National Petroleum Council report on refining.

²¹ PADD II consists of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, and Wisconsin.

Regarding the Far East products market:

- o Although PADD V is a net product exporter, the balance in light products is delicate. In 1992, PADD V exported 46 mb/d of light products and imported 31 mb/d. In 1993, the figures were about the same. Canada is the largest source of imported gasoline, jet fuel and naphtha, but several cargos from Venezuela, the Virgin Islands, Korea, Singapore, Saudi Arabia, China, Thailand, and Mexico also appear each year. This means that some industry companies found it economically feasible to purchase and ship products to the West Coast despite the high costs of travelling long distances in small tankers.
- o When Singapore product prices are increased by the cost of transporting product to the West Coast, they are seen to be close to West Coast levels. A mix of Singapore gasoline could be sold in PADD V for prices that are only two to four cents above existing Los Angeles and San Francisco pipeline spot prices, and at parity with spot prices in Seattle. Similarly, jet fuel is within two to four cents per gallon of West Coast spot prices.

Thus, the examination suggests that, in some cases, it might be financially viable to send cargos past Singapore to PADD V if PADD V prices rise a few cents per gallon. It is important not to over-stylize import economics. Market prices should be viewed as random variables with distributions that probably center near the prices quoted in trade papers such as those employed in this study. The closer two prices are together, on average, in separate markets, the more often nimble traders will find it profitable to buy in one market and to sell into another. The fact that we see an occasional light product cargo being shipped to the West Coast from Pacific, South American, and Caribbean countries verifies this characterization.

To examine the effect of other markets on West Coast markets, we began by attempting to characterize gasoline prices in California as a function of crude oil costs that refiners pay. To test the assumption that refiners' gasoline pricing is a direct response to oil cost changes, we performed a large number of simple data regressions. The first set of regressions linked the average refiner retail gasoline price in California to crude oil prices in the State. The statistical relationship was very poor, no matter whether we used monthly or quarterly data.

That analysis led to considering gasoline prices in the Gulf Coast market. A statistical analysis of the last six years of monthly prices indicated that California gasoline price movements correlate much more strongly with Gulf Coast (Texas) gasoline prices than they do with California refiners' crude oil supply costs. This implies that there is market arbitrage that keeps West Coast product prices in line with outside sources, even though little product moves between the West Coast and other regions.

The statistical analysis we conducted was purposefully simplistic, but revealing. Clearly, there is some relationship between crude oil costs and gasoline prices because the raw materials cost is about one-half the price of the finished product in California (more than half in Texas). Nevertheless, it seems that small to moderate price changes in California's gasoline market are better explained by events that shape gasoline markets elsewhere than they are by differences in California crude oil prices.

These observations suggest, but do not prove, the existence of a link between U.S. Gulf and California gasoline prices that may dominate small changes in California crude oil prices. Whatever that link is, however, it is not evident in EIA's supply data because little gasoline is observed moving between the Gulf and West Coasts. Most of what does move is shipped via pipeline from El Paso, Texas, to Phoenix, Arizona, and does not directly affect the huge California market.

Nevertheless, one might conjecture that arbitrage between markets would keep prices linked, or, at least, limited to a maximum difference. As long as no event destabilizes the basis of arbitrage (e.g., a sharp increase in tanker rates), it remains effective in linking prices without a significant amount of physical deliveries taking place. This phenomena might be compared to that in the spot and futures markets for petroleum and other commodities. Spot and futures prices vary within narrow limits and ultimately converge despite the fact that very little physical delivery is taken as a result of futures contracts.

THE JAPANESE MARKET FOR ANS CRUDE OIL

Before World War II, Japan was a major purchaser of U.S. West Coast crude oil. The crude was not from Alaska, of course; it was Wilmington crude from North Los Angeles. An examination of Japanese petroleum consumption and refinery configurations suggests that a market exists there today for ANS crude oil.

Oil provides more than half of Japan's primary energy supply, and virtually all of it is imported. Table 2.3 shows that Middle East countries provided three-quarters of Japan's supply in 1992, up from 68 percent in 1988. The shift was associated with reduced imports from Indonesia and Mexico. Within the Middle East, the United Arab Emirates and Saudi Arabia picked up Iraq's market share.

Over 60 percent of Japan's crude oil is provided by the producing countries' national oil companies. Only 27 percent is supplied by the international oil majors.

Japan's over four million barrels per day of crude oil supply includes at least 500 mb/d of Middle East crudes in the 32 to 34 degree API range (Saudi Light, Iranian Light, etc.). In addition, there is another 100 to 150 mb/d in that gravity range available from other sources (e.g., Mexican Isthmus crude oil). Compared to the United States, Japanese refinery inputs are light (i.e., high API degree levels) due to the addition of large amounts of Abu Dhabi and Qatar crudes. Most of these Middle East crudes, although of higher API gravity, also have more sulfur.

Table 2.3 Suppliers of Japan's Crude Oil (% of Total)

	<u>1988</u>	<u>1992</u>
Middle East Total	68.4%	75.2%
Saudi Arabia	14.4	21.5
U.A.E	20.0	24.3
Asia Total	17.4	14.8
Indonesia	13.3	10.0
Africa	0.7	0.4
Americas	5.4	2.3
China	7.8	5.9

Source: PAJ Annual Review 1992, Petroleum Association of Japan.

Japan's petroleum consumption is distributed much more uniformly across the product barrel than in the United States. Gasoline constitutes only 15 percent of product demand, for example, compared to 50 percent in California. The result is that distillates and residual fuels are more important elements of the refining process than are lighter products. Within those categories of fuels, excessive sulfur detracts significantly from the value of the product and the crude oil from which it is refined.

The combination of using lighter crude oils and low gasoline production allows Japanese refineries, on average, to be less complex than their U.S. counterparts. ANS crude oil fits this situation well due to its relatively low sulfur content and its good yield of distillate and kerosene-range products. Appendix C addresses refinery considerations in detail, describing the many considerations that, together, infer that ANS is a good candidate for sales to Japan.

In summary, ANS crude is not only geographically convenient to the Japanese market, it is also compatible with Japanese refineries. No attempt was made here to extend the detailed analysis to other Pacific Rim countries, but we felt that potential markets exist there also. Singapore, Korea, and Taiwan add another 2.0 to 2.5 million barrels per day of refining capacity. Korea and Taiwan are similar in their product needs and almost as close to Valdez as Japan. A closer examination may be warranted to determine limits to the size of the total export market that exists. At this point in our review, however, we thought it sufficient to conclude that Japan provide a ready source of sales for several hundred thousand barrels per day, probably as a replacement for a like amount of Arab Light crude oil, or a mix of ultra-light and heavy middle cost crudes.

OIL PRICE PROJECTIONS AND THE WEST COAST SUPPLY/DEMAND BALANCE

Rather than attempt to reach a consensus of opinion among knowledgeable petroleum economists about the future of oil prices, we elected to use two distinct scenarios to bound the uncertainties. The paragraphs below describe those cases.

Oil Prices

The study considers low and high price scenarios. In the first, world oil prices stay constant in real terms through the remainder of the decade. In the second, there is \$7.50 per barrel in real price growth during 1994 to 2000. These price paths, displayed in Table 2.4, are the high and low price paths from EIA's Annual Energy Outlook-1994 (AEO94).

Initially, we thought the low price case would be most favorable to ANS crude oil exports. Therefore, we elected to make assumptions in the low price case that were export-favorable, and do the opposite in the high price case. This approach was favored over a point estimate base case analysis due to the fairly wide range of uncertainty involved in some areas.

ANS and California crude oil price statistics were examined to determine their historic relationships to world oil prices. The historic relationships we found were assumed to continue until the West Coast crude oil supply excess disappears through either a natural decline in domestic production or exports of ANS crude oil.

Table 2.4 World Crude Oil Prices (1992 \$/Barrel)

	Low Price Case	High Price Case
1993	\$16.14	\$16.14
1994	15.43	17.50
1995	15.09	18.36
1996	14.89	19.43
1997	14.77	20.49
1998	14.85	21.70
1999	15.09	22.95
2000	15.44	24.16

Source: AEO94, and the Petroleum Marketing Monthly, EIA.

The West Coast Supply and Demand Balance

Product consumption and crude oil production in PADD V are two of the most important elements in this analysis. The method by which we established the balance and its future projections in the high and low price cases is described in detail in Appendix D. A few comments are appropriate here because the PADD V surplus is an integral component of the shipping discussion that follows.

Tables 2.5 and 2.6 describe the PADD V overflow in 1993 and subsequent years. In the low price case, the surplus disappears by 1997. In fact, there is a significant deficiency by 1997. At that point in this case, we assume that PADD V crude oil prices will rise to the level of imported foreign crude oils. Likewise, California heavy crude oil prices are also assumed to rise. Neither may be the case, but if a supply deficiency of 144 mb/d does not reduce the disparity in prices, then a few hundred thousand barrels per day of exports will not either.

In the high price case, the situation is substantially different. ANS production is higher (due to higher prices) and consumption is lower--thus, a larger surplus exists. Taken at face value, this scenario would seem to be one that would maximize the effect of exports on the U.S.-flag tanker fleet. That is, a higher surplus would require more tankers to transport it to the U.S. Gulf of Mexico, so exporting the surplus would eliminate more ships.

Table 2.5 ANS Crude Oil Surplus--Low Price Case

ANS Crude Oil PADD V Surplus Distribution (mb/d)								
	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>
PADD V Surplus	279	248	190	42	-144	-341	-539	-758
To Virgin Islands	97	84	84	0	0	0	0	0
To Mid-Continent	60	85	56	0	0	0	0	0
California Crude to Mid-Continent	53	53	50	42	0	0	0	0
ANS to Gulf Coast	69	26	0	0	0	0	0	0

Table 2.6 ANS Crude Oil Surplus--High Price Case

ANS Crude Oil PADD V Surplus Distribution (mb/d)								
	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>
PADD V Surplus	279	327	325	343	293	303	197	77
To Virgin Islands	97	100	100	100	100	100	57	0
To Mid-Continent	60	85	85	85	85	85	85	22
California Crude to Mid-Continent	53	55	55	55	55	55	55	55
ANS to Gulf Coast	69	87	85	103	53	63	0	0

At the same time, high prices keep crude oil production relatively robust, thereby eliminating much of the need for price-related actions. Because prices are high, the incremental production returns are lower in California (for reasons described in detail in Appendix E).

Our rationale (described in detail, Appendix D) in developing the distribution projections was as follows:

- o ANS oil shipments to the U.S. Gulf of Mexico via Panama would be the first non-PADD V shipments to be eliminated as the surplus falls.
- o ANS oil shipments through pipelines to the mid-continental United States would grow to 85 mb/d in 1994 due to increased pipeline capacity, and would stay at this level until the surplus disappears.

- o Shipments of ANS crude oil to the Virgin Islands would remain near their recent levels--about equal to pipeline shipments--until the PADD V surplus disappears (it is not clear that shipping ANS crude oil to the Virgin Islands is more or less profitable than shipping it to mid-continent refineries; we do not know the terms of crude oil pricing arrangements in these contracts).
- o The remainder of the surplus is assumed to be California crude oil shipped out on pipelines. Since this crude oil is now predominantly owned by All American Pipeline affiliated companies, the economics appear to be viable.

The PADD V surplus would continue throughout the decade if prices recover and remain high. Of note in the high price case are our assumptions that:

- o ANS oil shipments to the mid-continent are restricted only by pipeline capacity during most of the decade.
- o With ANS oil flowing through the All American Pipeline, it is likely that the pipeline's trading affiliates will still see it as economical to purchase and ship mid-California crudes eastward at their present rate.
- o Faced with a choice to ship to the Virgin Islands or sell in the U.S. Gulf of Mexico spot market, we believe that ANS crude sellers will take the former approach. Therefore, we kept Virgin Islands shipments near their highest historic levels until the surplus begins to disappear.

SHIPPING CONSIDERATIONS

A detailed, ship-by-ship examination of the current tanker fleet that carries ANS crude oil was made so that the effects of lifting the ban could be described properly. This was important because shipping costs are a significant component of profits and losses associated with exporting ANS crude oil. Many complex factors were involved, including:

- o Ports on the West Coast have restrictions that limit the size of a tanker that can be used to deliver oil there (e.g., Puget Sound is limited to tankers in the 120,000 deadweight tons (dwt) range or smaller). Other ports limit the amount of the larger ships' capacity that can be used (San Francisco's port has draft limitations, for example).
- o Tankers owned by ARCO and Exxon would tend to serve ports where those companies' refineries are located.
- o Before the year 2000, some ships will reach the dates that they must be rebuilt or retired due to the Oil Pollution Act of 1990 (OPA90).

This effort contained two main categories of analysis: sizing the fleet, and estimating shipping costs. These are summarized below and examined in greater detail in Appendix F.