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INCENTIVES FOR TERTIARY ENHANCED RECOVERY TECHNIQUES: CRUDE OIL PRODUCTION

GOVERNMENT

DOCUMENTS

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HEARING

BEFORE THE

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COMMITTEE ON

ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

NINETY-FIFTH CONGRESS

SECOND SESSION

ON

S. 2623

A BILL TO PROVIDE FOR INCREASED PETROLEUM PRODUCTION IN THE UNITED STATES THROUGH THE USE OF INCENTIVES FOR TERTIARY RECOVERY PROCESSES

S. 2999

A BILL TO AMEND THE FEDERAL NONNUCLEAR ENERGY RESEARCH AND DEVELOPMENT ACT OF 1974, AND FOR OTHER PURPOSES

JULY 17, 1978

Publication No. 95-155



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Committee on Energy and Natural Resources

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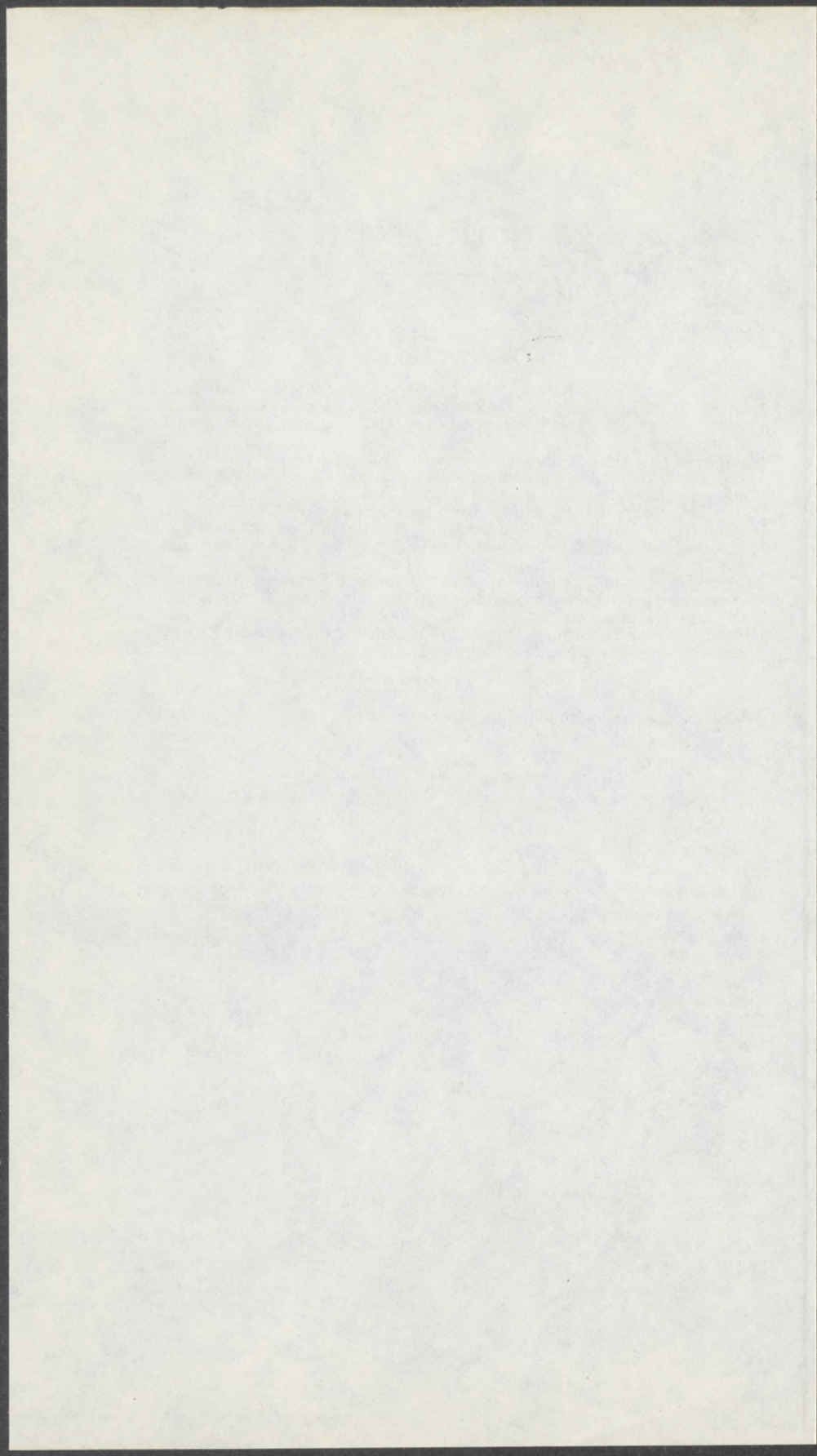
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INCENTIVES FOR TERTIARY ENHANCED RECOVERY TECHNIQUES: CRUDE OIL PRODUCTION

MONDAY, JULY 17, 1978

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C.

The committee met, pursuant to notice, at 10:05 a.m. in room 3110, Dirksen Office Building, Hon. Floyd K. Haskell, presiding.

Present: Senators Haskell, Hansen, and Bartlett.

Also present: Benjamin S. Cooper, professional staff member, and Danny Boggs, deputy minority counsel.

OPENING STATEMENT OF HON. FLOYD K. HASKELL, A U.S. SENATOR FROM THE STATE OF COLORADO

Senator HASKELL. The hearing of the Committee on Energy and Natural Resources will commence.

I would like to mention that the hearing today is on the potential for enhanced oil recovery techniques and appropriate governmental role in encouraging the realization of that potential occurs at a propitious time.

Both Houses of Congress and the administration are presently examining incentives for new oil production. In this examination of production incentives we must be careful to differentiate between those proposals which provide meaningful, necessary and responsible incentives and those which might merely result in windfall profits without significant increases in production.

From the evidence I have seen, incentives for enhanced oil recovery are necessary and can be productive if properly designed and implemented.

Today's hearing will examine the potential that enhanced oil recovery techniques offer for increasing our supplies and will explore the extent to which various incentives are needed to encourage tertiary operations.

The terms "enhanced oil recovery" or "tertiary recovery" are generic ones which cover a variety of processes.

Approximately two-thirds of the oil discovered in an average reservoir remains after primary and secondary production. Tertiary techniques have the potential of bringing another 30 percent of the oil to the surface.

Several studies have estimated the volume of petroleum resources technically recoverable as a result of application of these relatively new and high-risk technologies. The most recent study, the one prepared by the Office of Technology Assessment, estimated that 51

billion barrels—more than twice the estimated reserves in Prudhoe Bay—could be recovered, but that the amount that is likely to be recovered under present policies could be as little as 11 billion barrels.

The amount of oil potentially available through tertiary recovery techniques is therefore extremely significant and the timing for bringing it on line even more critical.

Under the right financial conditions, the Office of Technology Assessment, in its highly regarded study, found that tertiary recovery could supply 1.3 million barrels per day in 1985; 2.8 million in 1990; and 8.2 million in the year 2000.

Thus, in the mid to late 1980's when most experts agree that we will begin to experience worldwide oil shortages, EOR—enhanced oil recovery—could provide significant oil resources at the most critical time in our transition to the renewable energy resources of the future. This potential can only be realized if appropriate actions are undertaken in timely fashion.

In 1976, Congress recognized the potential of EOR in the Energy Conservation and Production Act when it directed the President “as soon as practicable after the date of enactment * * * to provide additional price incentives for bona fided tertiary enhanced recovery techniques.”

In spite of congressional instructions, the administration still has not established price incentives for EOR.

The most recent notice of rulemaking concerning tertiary recovery was published on August 17, 1977. This notice merely stated the intent of FEA to issue final regulations “in the near future.” Such regulations have not been forthcoming. Moreover, the administration's attitude toward EOR indicates to me that it considers EOR more as a political bargaining chip than a serious and immediate necessity.

Despite the fact that the President recommended decontrolling the price of EOR oil in the national energy plan, it was not included in that plan and it was dropped from the so-called phase II incentives. More recently it has popped up in the package of production incentives which the administration is offering industry in a last, desperate attempt to salvage its crude oil equalization tax (COET) plan.

I noticed in the Post this morning that the announcement of the committee's hearing stated “Enhanced Oil Recovery.” [Laughter.] Perhaps that's how the administration views the subject.

It seems obvious to me that it is time for Congress to realize that if actions are to be taken to provide incentives for tertiary recovery, they must be congressionally inspired.

Today, testimony will be presented by Senators Bentson and Hart both of whom have legislation on EOR pending before the committee; by the Department of Energy; and by representatives of industry and experts in the field.

It is the desire of the committee to allow all individuals to contribute their viewpoint so that we will have a complete information base upon which to take action.

I will insert at this point in the record the text of the two bills before us today.

[The text of S. 2623 and S. 2999 follow:]

95TH CONGRESS
2D SESSION

S. 2623

IN THE SENATE OF THE UNITED STATES

MARCH 1 (legislative day, FEBRUARY 6), 1978

Mr. BENTSEN introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

A BILL

To provide for increased petroleum production in the United States through the use of incentives for tertiary recovery processes.

1 *Be it enacted by the Senate and House of Representa-*
2 *tives of the United States of America in Congress assembled,*
3 That this Act may be cited as the "Tertiary Recovery In-
4 centives Act".

5 SEC. 2. The Emergency Petroleum Allocation Act of
6 1973 (Public Law 93-159) is amended by adding at the
7 end thereof the following new section:

8 "TERTIARY RECOVERY INCENTIVES

9 "SEC. 20. (a) For the purposes of this section qualified
10 tertiary recovery processes shall consist of those processes

1 including, but not limited to—misible fluid displacement,
2 steam drive injection, cyclic steam injection, microemulsion
3 flooding, in situ combustion, polymer augmented waterflood-
4 ing, immiscible carbon dioxide displacement, and variations
5 of such techniques, that an appropriate regulatory body, as
6 required by subsection (b) of this section, determines will
7 increase recovery of petroleum in excess of that which would
8 occur using only waterflooding techniques.

9 “(b) (1) The determination that a property is utilizing
10 a qualified tertiary recovery process shall be made by the
11 appropriate State regulatory bodies, as determined by the
12 Secretary of the Interior, for lands under their respective
13 regulatory jurisdictions and by the United States Geological
14 Survey for Federal land and Outer Continental Shelf areas.
15 The Economic Regulatory Administration of the Depart-
16 ment of Energy shall make such determinations only in those
17 cases where State regulatory agencies fail to do so.

18 “(2) A determination shall be made that a property is
19 utilizing a qualified tertiary recovery process where one of
20 the qualified tertiary recovery processes is being utilized and
21 the appropriate regulatory body determines that such process
22 could be expected to increase the petroleum production of
23 such property.

24 “(c) A determination that a property is utilizing a
25 qualified tertiary recovery process shall not be changed

1 unless there was fraud on the part of the producer in his
2 effort to receive such determination or due diligence is not
3 applied and maintained in the operation of such property.

4 “(d) Ceiling price controls on any crude oil produced
5 from a property where any qualifying tertiary recovery
6 process is utilized, as determined by the appropriate State or
7 Federal regulatory body, shall be suspended not later than
8 sixty days after the date of enactment of this Act.

9 “(e) Notwithstanding any other provision of this Act,
10 prices received for such crude oil shall be excluded from the
11 weighted average first sale price and from the composite
12 price of all domestic crude oil production as described under
13 the provisions of this Act.”.

95TH CONGRESS
2D SESSION

S. 2999

IN THE SENATE OF THE UNITED STATES

APRIL 27 (legislative day, APRIL 24), 1978

Mr. HART (for himself, Mr. DOMENICI, and Mr. HASKELL) introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

A BILL

To amend the Federal Nonnuclear Energy Research and Development Act of 1974, and for other purposes.

1 *Be it enacted by the Senate and House of Representa-*
2 *tives of the United States of America in Congress assembled,*
3 That this Act may be cited as the "Enhanced Oil Recovery
4 Commercialization Act of 1978".

5 SEC. 2. Section 7(a) of the Federal Nonnuclear En-
6 ergy Research and Development Act of 1974 (42 U.S.C.
7 5901) is amended—

8 (1) by striking out "and" after the semicolon at
9 the end of paragraph (5) ;

10 (2) by striking out the period at the end of para-
11 graph (6) and inserting in lieu thereof "; and"; and

1 (3) by adding at the end thereof the following new
2 paragraph:

3 “(7) Federal loan guarantees: *Provided*, That all
4 of the other provisions of this Act apply to such guar-
5 antees in the same manner and to the same extent as
6 they apply to demonstrations under this Act.”.

7 SEC. 3. (a) The Federal Nonnuclear Energy Research
8 and Development Act of 1974 is amended by inserting
9 after section 3:

10 “PART A—ENERGY RESEARCH AND DEVELOPMENT”.

11 (b) Such Act is further amended by adding at the
12 end thereof the following:

13 “PART B—LOAN GUARANTEES

14 “LOAN GUARANTEES FOR COMMERCIAL DEMONSTRATION
15 FACILITIES FOR ENHANCED OIL RECOVERY

16 “SEC. 20. (a) It is the purpose of this part—

17 “(1) to assure adequate Federal support to foster
18 a commercial demonstration program for new and im-
19 proved methods of enhanced oil recovery on a fieldwide
20 basis;

21 “(2) to insure that independent oil companies are
22 able to participate in the early phases of enhanced oil
23 recovery and thereby form an important part of an
24 enhanced oil recovery industry; and

1 “(3) to gather information about the technologi-
2 cal, economic, environmental, and social costs, benefits,
3 and impacts of such commercial demonstration facil-
4 ities, and thereby better understand the consequences
5 of a commercially enhanced oil recovery industry.

6 “(b) The Secretary is authorized in accordance with
7 such rules and regulations as he shall prescribe after consul-
8 tation with the Secretary of the Treasury, to guarantee and
9 to make commitments to guarantee, in such manner and
10 subject to such conditions as he deems appropriate, the pay-
11 ment of interest on, and the principal balance of, bonds,
12 debentures, notes, and other obligations issued by or on
13 behalf of any borrower for the purpose of financing the con-
14 struction and startup costs of full scale facilities and the re-
15 quired material to demonstrate on a fieldwide basis new and
16 improved methods of enhanced recovery of crude oil. The
17 outstanding indebtedness guaranteed and committed to be
18 guaranteed under this paragraph shall at no time exceed
19 \$200,000,000.

20 “(c) The full faith and credit of the United States is
21 pledged to the payment of all guarantees issued under this
22 section with respect to principal and interest.

23 “APPLICATION REQUIREMENTS

24 “SEC. 21. (a) An application for any guarantee under
25 this section shall be in such form and contain such informa-

tion as the Secretary deems necessary. Such application shall contain, as a minimum, assurances that an applicant seeking a guarantee under this part must be a citizen or national of the United States. A corporation, partnership, firm, or association shall not be deemed to be a citizen or national of the United States unless the Secretary determines that it satisfactorily meets all the requirements of section 802 of title 46, United States Code, for determining such citizenship, except that the provisions in subsection (a) of such section 802 concerning (1) the citizenship of officers or directors of a corporation, and (2) the interest required to be owned in the case of a corporation, association, or partnership operating a vessel in the coastwise trade, shall not be applicable.

“(b) Prior to issuing any guarantee under this section the Secretary shall obtain the concurrence of the Secretary of the Treasury with respect to the timing, interest rate, and substantial terms and conditions of such guarantee.

“CONDITIONS OF GUARANTEE

“SEC. 22. (a) The Secretary, with regard for the need for competition, shall guarantee or make a commitment to guarantee any obligation under subsection (b) only if—

“(1) the Secretary is satisfied that the financial assistance applied for is necessary to encourage participation by financial institutions; that the borrower owns

1 or controls the production of less than twenty-five thou-
2 sand barrels of oil per day and has made reasonable
3 efforts to obtain private financing for the commercial
4 demonstration facility and that such private financing is
5 unavailable on reasonable terms; additionally, in order
6 for a program to qualify working interest ownership in
7 the field by independent oil producers shall not be less
8 than 60 per centum;

9 “(2) the amount guaranteed does not exceed 85 per
10 centum of the total cost of the commercial demonstration
11 program, as determined by the Secretary;

12 “(3) the amount guaranteed may not exceed 90
13 per centum of the costs of implementation and startup
14 of the commercial demonstration facility;

15 “(4) the Secretary has determined that there will
16 be a continued reasonable assurance of full repayment;

17 “(5) the obligation is subject to the condition that
18 it not be subordinated to any other financing;

19 “(6) the Secretary has determined, taking into
20 consideration all available forms of assistance under this
21 section and other Federal statutes, that the environ-
22 mental impacts directly resulting from the proposed
23 operation have been fully evaluated by the borrower,
24 the Secretary, and others;

1 “(7) the maximum maturity of the obligation does
2 not exceed thirty years, or 90 per centum of the pro-
3 jected useful economic life of the physical assets of the
4 commercial demonstration facility covered by the guar-
5 antee, whichever is less, as determined by the Secretary.

6 “(8) the Secretary has determined that the recov-
7 ery and production methods to be used in the commercial
8 demonstration facility have been shown to be feasible in
9 an enhanced oil recovery technical pilot project study
10 in such field or similar geological area;

11 “(9) the Secretary has determined that there is
12 reasonable assurance that the recovery and production
13 methods to be used in the commercial demonstration
14 facility would be useful in other commercial projects
15 for enhanced oil recovery and the production of crude
16 oil from this technology; and

17 “(10) the Secretary has determined that this proj-
18 ect is needed to test whether the technology to be used
19 is economically viable on the respective geological
20 structure.

21 “(b) The Secretary shall review and approve the plans
22 of the applicant for the construction and operation of any
23 commercial demonstration program and related facilities
24 constructed or to be constructed with assistance under this
25 part. Such plans and the actual construction shall include such

1 monitoring and other data-gathering costs associated with
2 such program or facility as are required by the comprehen-
3 sive plan and program under this section. The Secretary
4 shall determine the estimated total cost of such demonstra-
5 tion program, including, but not limited to, construction
6 costs, chemical materials costs, and startup costs.

7 “(c) Except in accordance with reasonable terms and
8 conditions contained in the written contract of guarantee,
9 no guarantee issued or commitment to guarantee made under
10 this part shall be terminated, canceled, or otherwise revoked.
11 Such a guarantee or commitment shall be conclusive evidence
12 that the underlying obligation is in compliance with the pro-
13 visions of this section and that such obligation has been ap-
14 proved and is legal as to principal, interest, and other terms.
15 Subject to the conditions of the guarantee or commitment to
16 guarantee, such a guarantee shall be incontestable in the
17 hands of the holder of the guaranteed obligation, except as to
18 fraud or material misrepresentation on the part of the holder.

19

“DEFAULT

20 “SEC. 23. (a) If there is a default by the borrower, as
21 defined in regulations promulgated by the Secretary and in
22 the guarantee contract, the holder of the obligation shall
23 have the right to demand payment of the unpaid amount
24 from the Secretary. Within such period as may be speci-
25 fied in the guarantee or related agreements, the Secretary

1 shall pay to the holder of the obligation the unpaid interest
2 on and unpaid principal of the guaranteed obligation as to
3 which the borrower has defaulted, unless the Secretary finds
4 that there was no default by the borrower in the payment of
5 interest or principal or that such default has been remedied.
6 Noting in this section shall be construed to preclude any for-
7 bearance by the holder of the obligation for the benefit of
8 the borrower which may be agreed upon by the parties to
9 the guaranteed obligation and approved by the Secretary.

10 “(b) If the Secretary makes a payment under subsec-
11 tion (a) the Secretary shall be subrogated to the rights of
12 the recipient of such payment as specified in the guarantee
13 or related agreements including, where appropriate, the au-
14 thority (notwithstanding any other provision of law) to
15 complete, maintain, operate, lease, or otherwise dispose of
16 any property acquired pursuant to such guarantee or related
17 agreements or to permit the borrower, pursuant to an agree-
18 ment with the Secretary, to continue to pursue the purposes
19 of the commercial demonstration program if the Secretary
20 determines that this is in the public interest.

21 “(c) For purposes of this section, patents and tech-
22 nology resulting from the commercial demonstration pro-
23 gram shall be treated as project assets of such program
24 and facility in accordance with the terms and conditions
25 of the guarantee agreement.

1 “(d) With respect to any obligation guaranteed under
2 this section, the Secretary is authorized to enter into a
3 contract to pay, and to pay, the holders of the obligation,
4 for and on behalf of the borrower, from the fund established
5 by this section, as applicable, the principal and interest pay-
6 ments which become due and payable on the unpaid bal-
7 ance of such obligation if the Secretary finds that—

8 “(1) the borrower is unable to meet such payments
9 and is not in default and it is in the public interest to
10 permit the borrower to continue to pursue the purposes
11 of such demonstration facility and that the probable net
12 benefit to the Federal Government in paying such prin-
13 cipal and interest will be greater than that which would
14 result in the event of default;

15 “(2) the amount of such payment which the Sec-
16 retary is authorized to pay shall be no greater than the
17 amount of principal and interest which the borrower is
18 obligated to pay under the loan agreement; and

19 “(3) the borrower agrees to reimburse the Secre-
20 tary for such payment on terms and conditions, includ-
21 ing interest, which are satisfactory to the Secretary.

22 “REPORT

23 “SEC. 24. (a) The Secretary is directed to submit a
24 report to the Congress within one hundred and eighty days
25 after the enactment of this section and annually thereafter,

1 setting forth his recommendations on the best opportunities
2 to implement a program of Federal financial assistance
3 with the objective of demonstrating full scale enhanced oil
4 recovery production and conservation of energy.

5 “(b) The report submitted under subsection (a) shall
6 include a comprehensive plan and program to acquire in-
7 formation and evaluate the environmental, economic, social,
8 and technological impacts of the demonstration program
9 under this section. In preparing such a comprehensive plan
10 and program, the Secretary shall consult with the Environ-
11 mental Protection Agency, the Federal Energy Administra-
12 tion, the Department of Housing and Urban Development,
13 the Department of the Interior, and the Department of
14 Agriculture.

15 “(c) The comprehensive plan and program required by
16 subsection (b) shall include—

17 “(1) information about potential commercial dem-
18 onstration facilities proposed in the program under this
19 section;

20 “(2) any significant adverse impacts which may
21 result from any activity included in the program;

22 “(3) proposed regulations required to carry out the
23 purposes of this section;

24 “(4) a list of Federal agencies, governmental enti-

1 ties, and other persons that will be consulted or utilized
2 to implement the program; and

3 “(5) methods and procedures by which the infor-
4 mation gathered under the program will be analyzed and
5 disseminated.

6 “CONGRESSIONAL NOTIFICATION

7 “SEC. 25. Prior to issuing any guarantee or commitment
8 to guarantee pursuant to subsection (b) of this section, the
9 Secretary shall submit to the Congress a full and complete
10 report on the proposed commercial demonstration facility
11 and such guarantee.

12 “ENHANCED OIL RECOVERY FUND

13 “SEC. 26. (a) There is created within the Treasury a
14 separate fund (hereafter in this section called the ‘fund’)
15 which shall be available to the Secretary without fiscal year
16 limitation as a revolving fund for the purpose of carrying out
17 the program authorized by subsection (b) of section 20 and
18 section 23 of this part.

19 “(b) There are authorized to be appropriated to the
20 fund \$200,000,000 to be available until expended.

21 “(c) All payments on obligations, appropriate expenses
22 (including reimbursements to other Government accounts),
23 and repayments pursuant to operations of the Secretary
24 under this section shall be paid from the fund subject to

1 appropriations. If at any time the Secretary determines that
2 moneys in the fund exceed the present and reasonably fore-
3 seeable future requirements of the fund, such excess shall be
4 transferred to the general fund of the Treasury.

5 “(d) If at any time the moneys available in the fund
6 are insufficient to enable the Secretary to discharge his re-
7 sponsibilities as authorized by section 20 (b), and section
8 23 of this part, the Secretary shall issue to the Secretary of
9 the Treasury notes or other obligations in such forms and
10 denominations, bearing such maturities, and subject to such
11 terms and conditions as may be prescribed by the Secretary
12 of the Treasury. Redemption of such notes or obligations shall
13 be made by the Secretary from appropriations or other
14 moneys available under subsection (b) for loan guarantees
15 authorized by section 20 and section 23 of this part. Such
16 notes or other obligations shall bear interest at a rate de-
17 termined by the Secretary of the Treasury, which shall be
18 not less than a rate determined by taking into consideration
19 the average market yield on outstanding marketable obliga-
20 tions of the United States of comparable maturities during
21 the month preceding the issuance of the notes or other obliga-
22 tions. The Secretary of the Treasury shall purchase any
23 notes or other obligations issued hereunder and for that pur-
24 pose he is authorized to use as a public debt transaction the
25 proceeds from the sale of any securities issued under the

1 Second Liberty Bond Act; and the purpose for which securi-
2 ties may be issued under that Act are extended to include
3 any purchase of such notes or obligations. The Secretary of
4 the Treasury may at any time sell any of the notes or other
5 obligations acquired by him under this subsection. All re-
6 demptions, purchases, and sales by the Secretary of the
7 Treasury of such notes or other obligations shall be treated
8 as public debt transactions of the United States.

9 “(e) For the purposes of this section, the term—

10 “(1) ‘State’ means any State of the United States,
11 the District of Columbia, the Commonwealth of Puerto
12 Rico, Guam, the Virgin Islands, American Samoa, or
13 any territory or possession of the United States;

14 “(2) ‘United States’ means the several States, the
15 Commonwealth of Puerto Rico, the Virgin Islands,
16 Guam, and American Samoa; and

17 “(3) ‘borrower’ or ‘applicant’ shall include any
18 individual, firm, corporation, company, partnership, as-
19 sociation, society, trust, joint venture, joint stock com-
20 pany, or other non-Federal entity.

21 “(f) Inventions made or conceived in the course of or
22 under a guarantee authorized by this part shall be subject to
23 the title and waiver requirements and conditions of this Act.

24 “(g) With respect to any obligation which is issued .
25 after the enactment of this part by, or in behalf of, any

1 State, political subdivision, or Indian tribe and which is
2 either guaranteed under, or supported by taxes levied by
3 said issuer which are guaranteed under this section, the
4 interest paid on such obligation and received by the pur-
5 chaser thereof (or the purchaser's successor in interest)
6 shall be included in gross income for the purpose of chapter
7 1 of the Internal Revenue Code of 1954, as amended:
8 *Provided*, That the Administrator shall pay to such issuer out
9 of the fund established by this section such portion of the
10 interest on such obligations, as determined by the Secretary
11 of the Treasury to be appropriate after taking into account
12 current market yields (1) on obligations of said issuer, if
13 any, or (2) on other obligations with similar terms and
14 conditions the interest on which is not so included in gross
15 income for purposes of chapter 1 of said Code, and in ac-
16 cordance with, such terms and conditions as the Secretary of
17 the Treasury shall require.

18 "DISCLOSURE

19 "SEC. 27. (a) Each officer or employee of the Depart-
20 ment of Energy who performs any function or duty under
21 this section shall file a financial information statement with
22 the Secretary in such form as may be required. Such state-
23 ment shall contain—

24 "(1) such information as the Secretary may re-
25 quire to determine any possible financial conflicts of
26 interest;

1 “(2) a description of transactions, as specified by
2 the Secretary, between the officer or employee and a
3 party in interest. Such transactions shall include—

4 “(A) any sale or exchange, or leasing of any
5 property between the officer or employee and a
6 party in interest; and

7 “(B) any furnishing of goods, services (in-
8 cluding management services), or facilities between
9 the officer or employee and a party in interest.

10 “(b) For the purposes of this section the term ‘party
11 in interest’ means any entity which transacts business with
12 the Department of Energy and in which any director, officer,
13 or employee of the Department of Energy:

14 “(1) is an officer or director;

15 “(2) has directly or indirectly (as determined by
16 the Secretary in regulations) an ownership interest of
17 5 per centum or more; or

18 “(3) is a partner (if such entity is organized as
19 a partnership).

20 “(c) The Secretary may identify specific positions
21 within the Department which are of a nonpolicymaking
22 nature and provide that officers or employees occupying
23 such positions shall be exempt from the requirements of
24 this subsection.

25 “(d) Any officer or employee who is subject to, and
26 knowingly violates the provisions of this section or any

1 regulation issued thereunder shall be fined not more than
2 \$2,500 or imprisoned not more than one year, or both.

3 "EFFECT ON OTHER LAWS

4 "SEC. 28. Nothing in this part shall be construed as
5 affecting obligations of any borrower receiving a guarantee
6 pursuant to this part to comply with Federal and State en-
7 vironmental, land use, water, and health and safety laws and
8 regulations or to obtain applicable Federal and State per-
9 mits, licenses, and certificates.

10 "PUBLICATION OF INFORMATION

11 "SEC. 29. The information maintained by the Secretary
12 under this part shall be made available to the public, sub-
13 ject to the provisions of section 552 of title 5, United States
14 Code, and section 1905 of title 18, United States Code, and
15 to other Government agencies in a manner that will facili-
16 tate its dissemination. Upon a showing, satisfactory to the
17 Secretary by any person that any information, or portion
18 thereof, obtained under this part by the Secretary directly
19 or indirectly from such person would, if made public, di-
20 vulge trade secrets or other proprietary information of such
21 person, the Secretary shall not disclose such information and
22 disclosure thereof shall be punishable under section 1905
23 of title 18, United States Code. The Secretary shall, upon
24 request, provide such trade secrets or other proprietary in-
25 formation to—

1 “(1) any delegate of the Secretary for the purpose
2 of carrying out this part; and

3 “(2) the Attorney General, the Secretary of Agri-
4 culture, the Secretary of the Interior, the Federal Trade
5 Commission, the General Accounting Office, other Fed-
6 eral agencies, or heads of other Federal agencies, when
7 necessary to carry out their duties and responsibilities
8 under this part and other statutes, but such agencies and
9 agency heads shall not release such information to the
10 public. This part shall not be construed as authority to
11 withhold information from Congress, or from any com-
12 mittee of Congress upon request of the chairman. For the
13 purposes of this subsection, the term ‘person’ shall
14 include the borrower.

15 "DEFINITION

16 “SEC. 30. For purposes of this part the term ‘enhanced
17 recovery of crude oil’ means enhanced oil and gas recovery
18 technologies, including micellar-polymer flooding, immis-
19 cible carbon dioxide displacement, micellar-polymer aug-
20 mented waterflooding, thermal recovery and steam drive
21 injection, solvent extraction, and variations of such tech-
22 niques as will increase recovery of petroleum in excess of
23 that which would occur using only waterflood techniques as
24 determined by an appropriate regulatory body designated by
25 the Secretary.”.

1 SEC. 4. The Emergency Petroleum Allocation Act of
2 1973 (Public Law 93-159) is amended by adding at the
3 end thereof the following new section:

4 "GOVERNMENT PRICE GUARANTEES FOR PRODUCTION FROM
5 QUALIFIED TERTIARY ENHANCED OIL RECOVERY PRO-
6 GRAMS

7 "SEC. 20. (a) For the purposes of this section qualified
8 enhanced oil recovery processes shall consist of those proc-
9 esses including, but not limited to, micellar-polymer flood-
10 ing, thermal recovery, and steam drive injection, micellar-
11 polymer, augmented waterflooding, immiscible carbon diox-
12 ide displacement, and variations of such techniques, that an
13 appropriate regulatory body, as required by the Secretary,
14 determines will increase recovery of petroleum in excess of
15 that which would occur using only waterflooding techniques.

16 "(b) (1) The determination that a property is utiliz-
17 ing a qualified enhanced oil recovery process shall be made
18 by the appropriate State regulatory bodies, as determined
19 by the Secretary of the Interior, for lands under their respec-
20 tive regulatory jurisdictions and by the United States Geo-
21 logical Survey for Federal land and Outer Continental Shelf
22 areas. The Economic Regulatory Administration of the De-
23 partment of Energy shall make such determinations only in
24 those cases where State regulatory agencies fail to do so.

1 “(2) A determination shall be made that a property is
2 utilizing a qualified enhanced oil recovery process where one
3 of the qualified enhanced oil recovery processes is being uti-
4 lized and the appropriate regulatory body determines that
5 such process could be expected to increase the petroleum
6 production of such property.

7 “(c) A determination that a property is utilizing a
8 qualified enhanced oil recovery process shall not be changed
9 unless there was fraud on the part of the producer in his
10 effort to receive such determination or due diligence is not
11 applied and maintained in the operation of such property.

12 “(d) (1) Crude oil produced directly by enhanced oil
13 recovery methods, and in amounts exceeding that which was
14 or would be produced by primary and secondary (water
15 flood) recovery methods, shall not be regulated as to price.
16 The Secretary of Energy shall establish procedures for cal-
17 culating the incremental oil production as a result of en-
18 hanced oil recovery to be used when such procedures do not
19 exist with appropriate State regulatory agencies.

20 “(2) In cases where the unregulated oil price is in-
21 sufficiently high to encourage private investment in ‘first
22 of a kind’ enhanced oil recovery operations, the Secretary
23 may guarantee a price of \$25 per barrel in 1978 dollars,
24 and adjusted thereafter by the annual rate of inflation ac-
25 cording to the implicit gross national product deflator. Upon

1 unregulated sale of such oil from enhanced oil recovery
2 operations, the Secretary shall pay to the producer an
3 amount equal to any difference between the market price
4 and \$25 per barrel, adjusted for inflation. In order to decide
5 whether to grant a price guarantee for a particular en-
6 hanced oil recovery operation, the Secretary shall consider
7 the extent to which the qualifying enhanced oil recovery proc-
8 ess needs to be, or has been, demonstrated as commercially
9 viable.

10 “(3) The Department of Energy shall establish yearly
11 mean projections for world oil prices based on estimates of
12 the supply of and demand for world oil. Based on estimates
13 of the projected difference between the support price of \$25
14 per barrel and the world oil price for each year of an en-
15 hanced oil recovery operation, the Department of Energy
16 shall calculate the likely maximum cost of the price support
17 for each enhanced oil recovery operation so supported.

18 “(4) There are authorized to be appropriated to carry
19 out the purposes of this subsection \$20,000,000 for the fiscal
20 year ending September 30, 1980, \$30,000,000 for the fiscal
21 year ending September 30, 1981, \$50,000,000 for the fiscal
22 year ending September 30, 1982, and \$100,000,000 for the
23 fiscal year ending September 30, 1983.

24 “(e) Notwithstanding any other provision of this Act,
25 prices received for such crude oil shall be excluded from

1 the weighted average first sale price and from the composite
2 price of all domestic crude oil production as described under
3 the provisions of this Act.”.

4 SEC. 5. (a) Regulations required by this section shall
5 be issued within one hundred and eighty days after enact-
6 ment of this section, except as provided in subsection (s)
7 of this section.

8 (b) No part of the program authorized by this section
9 shall be transferred to any other agency or authority, except
10 pursuant to Act of Congress enacted after the date of enact-
11 ment of this section.

Senator HASKELL. It is my great pleasure to welcome the Honorable Lloyd Bentsen as the first witness.

Senator BENTSEN. Thank you very much, Mr. Chairman.

Senator BARTLETT. Mr. Chairman, I have an opening statement, but I'll be happy to make it after Senator Bentsen and Senator Hart speak, because I will be here the whole time.

Senator HASKELL. Oh, excuse me, Senator. I didn't see you, but go ahead.

STATEMENT OF HON. LLOYD BENTSEN, A U.S. SENATOR FROM THE STATE OF TEXAS

Senator BENTSEN. I thank my distinguished friends from Colorado and Oklahoma, and I appreciate very much the opportunity to appear before you to discuss an issue that is not only important to my State and to your States, but one that's important to the entire Nation, and that's the issue of adequate tertiary recovery incentives.

Maximizing domestic production is vitally important to our Nation in terms of maximizing national security, trying to do something about balance of trade, and trying to stop the deterioration of the dollar and the increase of inflation in this country.

A very important part of our opportunity to increase domestic production lies in improved recovery of the oil we have already found. Increasing recovery and production rates above that which will be realized by primary recovery and secondary recovery is the target of tertiary recovery methods. These techniques include, but are not necessarily limited to, miscible fluid displacement, steam drive injection, cyclic steam injection, microemulsion flooding, in situ combustion, polymer augmented waterflooding, immiscible carbon dioxide displacement and variations of such techniques.

The opportunity for improving recovery from known petroleum reserves is immense. Out of the 450 billion barrels of crude oil discovered in this country, 115 billion barrels have been recovered to date. Remaining reserves using existing economic techniques are estimated to be about only some 30 billion barrels. That means that only 32 percent of the domestic oil we have found will be recovered while 300 billion barrels will be left in the ground unless steps are taken to provide economically attractive opportunities to develop new technology and to undertake tertiary recovery programs.

Several studies have been made by Government agencies. And, Mr. Chairman, you cited some of them, and got them in detail, and some of them that were valuable studies. But they show the tremendous potential that we have for recovery of oil by tertiary methods.

I would like to introduce the executive summary of two of these studies as exhibits to be included in the record if I may, Mr. Chairman.

Senator HASKELL. They will be so included at the conclusion of your remarks.

Senator BENTSEN. These exhibits are the summaries of a report entitled "Review of Secondary and Tertiary Recovery of Crude Oil," prepared by Lewin & Associates for the Federal Energy Administration in June 1975, and a report entitled "Enhanced Oil Recovery Potential in the United States," prepared by the Office of Technology Assessment in January 1978.

Now these studies indicate that there are many variables which influence the amount of recovery that can be realized from tertiary recovery projects, but by far the most important variable is that of price incentive.

The Lewin & Associates study concluded that the potentially enhanced oil recovery of the total for the United States was "very large" indeed. It estimated the potential to be 65 billion barrels if all production from approved exotic enhanced recovery projects were released from price controls.

The study also concluded that lesser incentives, such as decontrolling only the incrementally enhanced oil, would result in a "small" amount of added reserves.

One of the recommendations contained in the report is that "all production from approved exotic enhanced recovery projects be released from price controls."

When I first looked at this problem I was convinced the way to go was on incremental production. But then I began to look at the problems of differentiating, determining which was the incrementally induced production. And then I began to look at the results of these studies as to how much would actually be accomplished in increased production by going the incremental route compared to releasing the production entirely. And when I saw the differences in production, I tilted on the side of releasing the entire property.

Now when I use the term "property," Mr. Chairman, I'm not inferring that one could apply tertiary techniques to one corner of a field or one large property, and then the entire area would be released from price controls. Instead, only that area that is influenced by the tertiary recovery or those wells directly affected would be released from controls.

Senator HASKELL. Can that be ascertained?

Senator BENTSEN. It can be ascertained as easily as the incremental production. And it must be a determination made by the appropriate State regulatory agency.

The report prepared by the Office of Technology Assessment shows that an estimated enhanced oil recovery ranging from 8 to 42 billion barrels of oil, and by 1990 potential rate increases from 0.5 to 2.8 million barrels of oil per day. Now that shows you some of the problems of companies in deciding to go into these projects. These studies show such a great variation as to what that recovery is going to be, from 8 to 42 billion barrels of oil—that's their estimate—from 0.5 to 2.8 million barrels per day. But if they are right—and the figure of 2.8 is a possibility that could be brought about by tertiary recovery—if they're right, if I remember my numbers, that is comparable to the potential savings of the entire energy package of the President. I believe you would come up with comparable numbers; that this would go a long way toward matching the savings of the entire energy package of the President.

These tertiary projects are going to be risky, both from a process standpoint—how well is the process going to work—and from a reservoir standpoint—how amenable is each reservoir to this particular method? With time, the process risks are going to decrease. And the reason the process risk will decrease is because they will be proven over a period of time. But the other side is that the reservoir risks are going to increase. The reason is that an untested process will

first be tried on the most proven and largest reservoirs. And if it works there, then they are going to work on down to those that are more speculative.

I have a friend back in Texas who kept telling me how he was going to make a fortune, and he had a small one already, but how he was going to make it——

Senator HASKELL. By Texas standards or by——

Senator BENTSEN. I don't know. By anybody's standards. [Laughter.]

Unfortunately, not by Saudi Arabian standards. [Laughter.]

Incidentally, the other day I just read about the richest man in oil being from Colorado. But that's another story. [Laughter.]

That's another point.

Senator HASKELL. And I just finished the book, "The Crash of 1979." [Laughter.]

Senator BENTSEN. But my friend is broke today because he lost it all trying to do a fire flooding project. It is highly speculative.

As I mentioned earlier, one of the important reasons for maximizing domestic crude oil production is to minimize that balance of payments.

The Department of Energy recently reported that the latest estimates of the balance of payments cost of foreign oil to the United States in 1978 now ranges from \$47 billion to \$49 billion.

Undoubtedly, this balance-of-payments impact will steadily increase in the years ahead as both the quantity and the price of imported oil increases. At the current price of \$15 per barrel, an increase in domestic production from tertiary recovery projects of say 2 million barrels a day would decrease the balance of payments for imported oil by about \$11 billion per year in 1978 dollars.

Senator HASKELL. Would you care, Senator, to compare the oil produced by tertiary recovery with the administration's claims for savings under COET?

Senator BENTSEN. Well I don't think you are going to see much savings under COET in two ways. First, if it was enacted, and, second, it isn't going to be enacted.

Senator HASKELL. Well let's assume it was. My understanding is they claim 200,000 barrels a day.

Senator BENTSEN. Which, as you are pointing out, is infinitesimal in comparison to what we could get out of tertiary recovery. And if you put the whole energy package together and passed it as the administration had proposed it, you would do as much by this one bill as you would save by that whole package.

Now recognizing the extreme importance of tertiary recovery projects to the domestic energy supply, the Congress, in the Energy Policy and Conservation Act of 1975, provided for a price adjustment as a production incentive for application of enhanced recovery techniques. And again in the Energy Conservation and Production Act of 1976, Congress directed that:

As soon as practicable after the date of enactment, the President shall promulgate such amendments as shall provide additional price incentives for bona fide tertiary enhanced recovery techniques.

The ECPA conference report identified as a matter of high priority the creation of these price incentives and stated that the President is directed to amend the regulations "at the earliest practical date to provide for these congressionally identified priorities."

I agree with you, Mr. Chairman, we are going to have to do it here because we have not seen it accomplished in those 2 years.

Existing crude price regulations provide upper tier prices for crude oil volumes produced in excess of the base control level. Now that's not a special incentive for tertiary recovery, but simply the basic regulation that is applicable to any increase in production from property.

The Economic Regulatory Administration solicited public comments on several occasions with regard to incentives for tertiary recovery techniques. Industry testimony, in general, indicated strong opposition proposals which would provide incentive prices only for incremental production from tertiary recovery projects because of the inadequacy of such pricing to bring forth substantial tertiary recovery programs, the administrative complexities of identifying incremental production, and problems in certifying projects.

Mr. Chairman, although all tertiary recovery techniques are expensive, some are much more costly than others. By providing a decontrolled price for only the incremental production, or increase in production, we will generate sufficient revenues to finance only the least costly enhanced recovery projects.

We may increase production somewhat—I think we will—but we will end up leaving substantial reserves in the ground. Much of these reserves left behind could be recovered if we decontrolled all oil produced from the tertiary recovery projects, as I have proposed in my bill.

And I know that some are concerned that complete decontrol will permit some producers to realize increased profits on oil already in production. And I agree that that may periodically happen. But I am convinced that anything less than full decontrol of tertiary projects will not provide the level and certainty of return needed to finance these costly and high-risk projects. And that's what these studies have all shown.

I don't see anything wrong with giving domestic producers the same price for oil that we give foreign producers if it will guarantee a substantial increase in domestic production.

The Department of Energy's approach to tertiary incentives, published in the Federal Register on August 11, 1977, has yet to be implemented through final regulations. It is apparent that we are going to have to pass the legislation here. Without prompt action, some of the reservoirs which offer tertiary recovery potential will be depleted and the wells will be abandoned. And after they are capped, the cost of going back in with a tertiary recovery technique is substantially higher and many of the projects would have to be forgotten.

Now that means the opportunity for increasing tertiary recovery techniques is going to be lost forever. To prevent further delay, I have introduced S. 2623, the Tertiary Recovery Incentives Act, which would provide the needed incentives for producers to undertake tertiary recovery processes.

The key elements of the bill are these:

1. Ceiling price controls are suspended on all crude oil produced from a property. And again I am talking about that area of that property that's affected by the tertiary process. This may cause some concern that the proposal would allow the producer to make too much profit on a barrel of oil. But I really don't think that's the case. These tertiary

recovery processes require a great deal of engineering study, a substantial investment before they start, and very expensive substances to be injected into the wells. And then you have a substantial delay before you begin to see the increase in production. Under my bill, producers would not see prices go to the world prices on that area of oil affected until they began injecting the substances.

2. A determination shall be made by the appropriate regulatory agency that a property is utilizing a qualified tertiary recovery process as identified in the bill, and that such process could be expected to increase the petroleum production of the property. This provision insures that only bona fide tertiary recovery projects receive the higher incentive price.

3. A determination that a property is utilizing a qualified tertiary recovery process shall not be changed unless there is a fraud on the part of the producer in his effort to receive such a determination or unless diligence is not applied and maintained in the operation of such a property.

And the reason for this provision is to prevent someone from making that kind of a very major investment and then finding himself subject to some capricious decision by the bureaucracy. Once you have made that investment and made that commitment, as long as there is no fraud in setting it up and qualifying for it, and you continued to apply due diligence in the application of the process, then the designation should not change.

4. Prices received for production from a qualifying tertiary recovery process shall be excluded from the weighted average first-sale price and from the composite price of all domestic crude oil production. Without such a provision, any increase in prices allowed for tertiary recovery will result in decreased incentives for other oil recovery ventures.

Mr. Chairman, providing adequate tertiary recovery incentives is a vital element in any program to increase our Nation's domestic crude oil supplies. In two separate pieces of legislation, the Energy Policy and Conservation Act and the Energy Conservation and Production Act, Congress has sought special incentives for tertiary recovery projects. However, after more than 2 years, the Nation still is without a program that provides the needed incentives for developing production from potential tertiary projects. And the longer we wait, the more these reservoirs are going to be abandoned and the more wells are going to be tapped, and the less chance of recovering reserves that will otherwise be left in the ground and lost to the cause of the United States.

Mr. Chairman and members of this committee, I appreciate very much the opportunity to appear before you.

Senator HASKELL. Thank you, Senator.

You indicate that your bill would state that, where tertiary recovery is used in a field which may also be subject to some other method, either primary or secondary, there would be a determination of the amount of oil that was produced by the tertiary method. Am I correct in that? In other words, you've got a field and maybe you've got—

Senator BENTSEN. Well I would decontrol both the old oil and the incremental oil of that area affected by the tertiary recovery. There is a commingling of the oil and it's a pretty difficult thing to judge what the incremental increase is. That's a complex thing to determine.

Senator HASKELL. That's the point I was getting at.

Senator BENTSEN. Yes.

Senator HASKELL. Now who in your bill would make that determination, what agency?

Senator BENTSEN. I would have the State regulatory agency do it.

Senator HASKELL. Do you believe, Senator, that decontrol by itself is sufficient to reduce substantial tertiary recovery?

Senator BENTSEN. Yes. But, of course, they would have to certify that the project was using an approved tertiary recovery method. And I am citing these two studies that I have presented for the record that say that if you decontrol the property—and I want to be sure we understand the property I am referring to is the property affected by the tertiary recovery method—that you will have a very substantial increase from one-half to 2.8 million barrels a day by 1990. And that if you go just to the incremental, the increase will be nominal.

Senator HASKELL. Staff has indicated to me that the OTA report asks for a compulsory unitization statute and in your State specifically. I assume it favors such statutes in other States, so that the owners of a reservoir can organize a unified tertiary recovery effort.

Do you have any comments on that?

Senator BENTSEN. Well you are getting into quite a complex subject for a fellow that's not a petroleum engineer.

Senator HASKELL. Well, Senator, you are pretty good at it. [Laughter.]

Senator BENTSEN. Well, I will defer on that point to someone more knowledgeable than I.

Senator HASKELL. I see. Thank you very much.

Senator BENTSEN. Thank you.

Senator HASKELL. Senator Hansen.

Senator HANSEN. Before yielding to Senator Bartlett, which I would like to do, Mr. Chairman, because he was here before I was—I regret not being here sooner—I would just make one observation on the question you asked Senator Bentsen.

For 4 years, I was Governor of Wyoming and we had a regulatory agency such as Senator Bentsen alluded to. The States have a variety of different situations, and I would prefer to leave that enforcement technique or whatever requirement might be imposed upon the industry to each State to decide. I think they have worked out a rather ingenious way of handling the problem. And it would be my observation—you didn't ask me, but it would be my observation—that that had better be left to State authority.

I would like to yield to Senator Bartlett, Mr. Chairman.

Senator HASKELL. Senator Bartlett.

Senator BARTLETT. Thank you, Mr. Chairman. And thank you, my colleague from Wyoming.

I would certainly agree with the statement you made about having the State regulatory agencies play a large role in this. In the first place, they have the knowledge of the individual fields and the techniques that are used. And they have knowledge and experience that the Federal Government doesn't have. I think that they are in a much better position to make a good judgment.

I congratulate the distinguished Senator from Texas. I think his presentation was done with force, and with knowledge and conviction.

There's no question that we have been ignoring, as the Senator brought out, known oil reserves and have prevented these reserves from being produced.

I do have a question or two.

Paragraph (e) of your bill—

Senator HANSEN. If I could interrupt, Senator Bartlett.

I know that you have been a leader in proposing legislation in this area. Do you have an opening statement?

Senator BARTLETT. Yes. And I announced earlier that I would make it after Senator Hart finishes his.

Senator HANSEN. I see. Fine.

Senator BARTLETT. Because I am going to be here anyway.

Senator HANSEN. I'm sorry. Excuse me for interrupting.

Senator BARTLETT. I think that was agreeable with the chairman. I thank the distinguished Senator from Wyoming.

In paragraph (e) of your bill—Senate bill 2623—it excludes enhanced recovery oil from the calculation of the weighted average first sale, or composite, price of all domestic crude oil production.

I have a bill which I will introduce today, and which I have introduced as amendments before, on enhanced recovery which covers secondary recovery of oil. Let me read a paragraph in it that deals with this same point but treats it differently.

For purposes of this section, the President shall include in the computation of the actual weighted average first sale price of crude oil produced in the United States in any month subsequent to the month of enactment of this subsection, the actual volume of enhanced recovery crude oil and such actual volume shall be deemed to have been sold at a first sale price which equals the average price for which such crude oil would have been sold if the exemption under this subsection had not been in effect.

In other words, your bill excludes the enhanced recovery oil that would be produced from consideration in the composite.

Now if that happened to be very low-priced oil, then that would leave higher-tier oil affecting the average price of oil remaining under the composite, to raise it up to the extent that the composite—well, as you know, the composite is limited. And this could ratchet down—

Senator BENTSEN. I can see the point you are about to make—yes.

Senator BARTLETT. So I feel that doing it the way we have in our proposal, then, does not affect in any way the composite and, hence, doesn't affect the higher-tier oil.

Does that seem to make sense?

Senator BENTSEN. It adds up to me, Senator. And I can see the point you are making. If we had picked a low-priced oil that's brought out from under the composite because it came under tertiary recovery, that we would have a debilitating effect which would actually drive down the price of oil under the composite.

Senator BARTLETT. Yes.

One other question, and this concerns paragraph (c). Do you have it before you?

Senator BENTSEN. No; I don't have it before me.

Senator BARTLETT. I'm sorry. I am not trying to catch you at all. I am with you.

Senator BENTSEN. No, I know you're not. And I think you have made a valid point there and I'm delighted.

Which one are you on now?

Senator BARTLETT. I think it's paragraph (c).

Senator BENTSEN. All right.

Senator BARTLETT. Senate bill 2623. Could you give us your definition of the term "due diligence" as used here, as it relates to an operator qualifying for price relief?

Senator BENTSEN. Well I think that that is a term that has been defined by the courts and I would leave it to them rather than my trying to define it from the top of my head, Senator.

Senator BARTLETT. Has that not been defined or at least accepted by the Texas Railroad Commission and the various other regulatory agencies?

Senator BENTSEN. Time and time again; yes.

Senator BARTLETT. I thank the distinguished Senator and I certainly appreciate his presentation. I think the point he is making, that we have dilly-dallied on this matter of tertiary recovery, is a valid one, and that we should get about the business. And I agree with the point that the chairman made, that the one way we are going to know that we are going to get something done is for the Congress to act and do something in this session.

I thank the distinguished Senator.

Senator BENTSEN. Thank you very much.

Senator HASKELL. Senator Hansen.

Senator HANSEN. I do have two questions, Senator Bentsen. First, let me express my real appreciation for your presence here this morning and your obvious interest in a matter that I think is extremely critical. I was impressed with your testimony.

My questions are two. Why not give the same incentive to other hard to get domestic oil such as shale oil, deep offshore oil, and Alaskan oil?

Senator BENTSEN. Well we will be getting incentives. And our finance committee, as you know, Senator, has worked on some incentives for the production of oil from shale and other more exotic sources. And I think we should.

I certainly agree that incentives have to be had to increase production of oil from other sources.

Senator HANSEN. I want to underscore a point you had made in your testimony.

Senator BENTSEN. Let me also make another point. There is not as much time pressure on those others as there is on this, because these wells are being abandoned and they are being capped, and these fields are being walked away from. Unless we move on it, this oil is going to be lost. And the cost of going back in where those wells are capped, drilling new wells, would be substantially more and the project would not be economical.

Senator HANSEN. I am glad you made that point because that's what I've been harping on. We have that situation in Wyoming. As a matter of fact, I'm told there isn't a major oilfield in the United States, no matter how long ago it was discovered, that has been completely abandoned. And the point is, as you so aptly put it, that we are running out of time in these fields. Amoco is shutting down between 25 and 50 wells per year in the Salt Creek field alone, and they say that they are going to abandon 50 million barrels of oil just in that one field that could be recovered if we had some price relief. Absent price relief, we are not going to get that oil out. And it's the

potential recovery of more oil economically in those old fields is such that it just doesn't make sense to go back in after a field has been shut down and abandoned to do the things necessary.

My second question: Why are price incentives for enhanced oil recovery necessary after a process has been proven?

Senator BENTSEN. Well the process is really only proven in the laboratory or it is proven perhaps in a particular reservoir. But there can be substantial changes from one reservoir to another. And as I cited earlier, as you go along there will be less risk in the process as they begin to prove it, but you will have more risk in the reservoirs because they will go first to those reservoirs that have the greatest potential, the most certainty, and then they will move on.

But I have seen pilot plant after pilot plant that has been tried with some great idea that didn't work when you tried it in real life. I have seen presidents of companies lose their jobs over the commitment of millions and millions of dollars to some project which they thought had been proven in the pilot operation.

I can show you in Brownsville, Tex., a large chemical plant that was put there many years ago, but is rusted away now. And it was proven in the pilot plant. But when they tried it in real life, and they built it, and they invested the stockholders' money, it didn't work. The same thing happens with these projects.

Senator HANSEN. And your point is that while we will learn a lot—it will be helpful and have wide applicability—there really aren't any two fields that are clearly identical in every respect. I think you also made that point.

Senator BENTSEN. That's right.

Senator HANSEN. Thank you, Mr. Chairman. Thank you, Senator.

Senator BENTSEN. Thank you.

Senator BARTLETT. Could I ask the Senator another question just along this same line?

Senator HASKELL. Certainly.

Senator BARTLETT. And I think you made the point. Is it true that some reservoirs are more costly to use a particular tertiary recovery method on? And also that some, as you pointed out, respond better than others, and can be anticipated to respond better because of a higher percentage of oil in place.

Senator BENTSEN. Well I think that's certainly true. But you can get some terrible surprises even with all the experts working at it because of the great difference in reservoirs. And the fact is that it frequently works in one and almost inexplicably sometimes will not work in another to the extent anticipated.

Senator BARTLETT. I thank the Senator.

Senator HASKELL. Thank you very much, Senator Bentsen. We appreciate it.

Senator BENTSEN. Thank you.

[The summaries submitted by Senator Bentsen follow:]

I. Executive Summary

Introduction and Summary of Findings

Since 1970, the Nation's known oil reserves have declined by an average 3.8 percent a year as discoveries of new oil continued to lag behind domestic production. During that same period, domestic production has declined steadily from its 1970 peak of 9.6 million barrels a day (MMBD) to 8.0 MMBD in early 1977. These declines, coupled with the disruptive 1973-74 Organization of Petroleum Exporting Countries (OPEC) oil embargo and a four-fold increase in world oil prices, have not yet depressed demand for oil in the United States. Except for a temporary drop in consumption in 1975, the United States has continued to increase its demand each year and imports have climbed steadily to make up the difference between domestic supplies and domestic demand.

Unless steps are taken to reduce demand, increase domestic production, or achieve some combination of both, the United States will be obliged to continue to increase its imports, which averaged 8.8 million barrels a day during the first 8 months of 1977. The United States would remain vulnerable to future embargoes or arbitrary price increases. Increased U.S. oil imports could contribute to imbalances between supply and demand on a world scale in the early 1980's that would mean even sharper increases in world prices.

There are only two ways to increase domestic production:

- accelerate exploration for new oil supplies, particularly along the Outer Continental Shelf; and
- develop more efficient methods for recovering oil which remains in the ground in known reservoirs after the first and second phases of conventional oil production.

This report concentrates on the second approach and assesses the potential for increasing domestic production from such known reservoirs

with five technologies and methods, known collectively as enhanced oil recovery (EOR) techniques.

The target for these EOR techniques is some 298 billion barrels of oil that will remain trapped in known sandstone and limestone reservoirs in the United States after producers have pumped all of the oil that can be taken with primary and secondary production methods. The EOR processes use heat or chemical fluids which are injected into reservoirs to sweep additional amounts of oil from the sandstone and limestone pore spaces and force it to the surface.

Recent studies of the potential production possible with EOR techniques have arrived at estimates that range all the way from 7 billion to 76 billion barrels of oil at prices ranging from \$10 to \$15 per barrel. Estimates of the rate of production as of 1985 range from 0.9 MMBD to 2.3 MMBD.

The major findings of the Office of Technology Assessment study are:

- At current world oil prices (\$13.75 per barrel in 1976 dollars¹), EOR techniques could add between 11 billion and 29 billion barrels of oil to existing domestic reserves. Annual production rates could range from 0.5 MMBD to 1.0 MMBD in 1985 and from 0.7 MMBD to 1.7 MMBD in 1990.
- At the price at which synthetic oil or other alternate sources might become available (\$22 per barrel), the potential for EOR appears to be between 25 billion and 42 billion barrels, with daily production rates

¹\$13.75 is the January 1977 average price (\$14.32 per barrel) of foreign oil delivered to the east coast, deflated to July 1, 1976. Only the incremental oil resulting from EOR techniques would be eligible for the prices used in this assessment; current and future oil production resulting from primary and secondary methods was assumed to be at price levels existing in 1976.

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of between 0.9 MMBD and 1.3 MMBD in 1985 and 1.8 MMBD to 2.8 MMBD in 1990.

- A vigorous program of research and development, with many field tests supported by laboratory investigations, must be undertaken to achieve significant EOR production. Even with such a program, eventual production would depend on the effectiveness of EOR processes and the validity of estimates of the amounts of oil remaining in the known reservoirs.
- Estimates of the daily rates of EOR oil production are much less certain than those for ultimate oil production, partly because the rate of development of EOR technology is uncertain and partly because EOR operations will have to compete for funds with other investment opportunities. Enhanced oil recovery processes are relatively new and the investment risk is high compared to more familiar oil exploration and production methods. If the oil industry hesitates to invest large amounts of capital in EOR processes in the next few years, the production of oil with enhanced methods would be delayed.
- Estimates of EOR potential presume the availability of very large quantities of injection materials, such as carbon dioxide (CO₂) and surfactant. A 50-percent increase in the real cost of these two materials could limit potential EOR production to 6 billion to 12 billion barrels at the world oil price, or 16 billion to 33 billion barrels at the alternate fuels price.
- The responsiveness of EOR potential to increases in the real price of oil drops off above \$22 per barrel. An increase in price to \$30 per barrel has the potential of increasing the production only about 17 percent, from 42 billion barrels to 49 billion barrels (assuming high process performance). Removing all economic constraints might add about 2 billion barrels more. Thus, it is doubtful that more than about 51 billion of the remaining 300 billion barrels of oil can be recovered under any economic conditions using current and foreseeable enhanced recovery technology.
- Investment tax incentives (a change from 10 to 12 percent in the investment tax credit and accelerated depreciation) appear to have relatively little effect on investor decisions to use EOR processes, but an Internal Revenue Service interpretation that the cost of injection chemicals must be depreciated rather than treated as an expense could seriously inhibit the use of the high-potential surfactant/polymer and CO₂ miscible processes.
- Neither a guarantee of \$13.75 per barrel nor a 15-percent investment subsidy would substantially reduce the element of risk in EOR decisions for investors.
- If investors expect real oil prices to rise at an average annual rate of 5 percent, decontrolling the price of oil produced by EOR techniques would reduce risk and increase potential production more than all other tax and price policies examined, including a \$3 per barrel subsidy.
- Any effort to permit a higher price for oil produced by EOR processes than that allowed for other oil produced from the same reservoir would require a fairly precise determination of the fraction of total oil production that resulted from EOR operations. Highly technical judgments would be involved, and there is some doubt that qualified personnel would be available at the Federal or State levels to undertake this task.
- In general, the environmental impacts of EOR techniques are not expected to be significantly different from those of primary and secondary production operations. There are two main exceptions. First, combustion of oil in thermal processes produces atmospheric pollutants. Until technology is implemented to control these emissions, air quality standards are expected to limit expansion of thermal processes already being used in California. Second, some EOR processes may require large volumes of fresh water, which could strain the capacity of local water supplies. Application of EOR technology which allows the use of saline water could reduce this problem.

- In order to undertake fieldwide oil recovery operations (waterflood or EOR), it is generally necessary to secure the consent of all parties with an interest in the field through a unitization agreement. Owners of relatively small interests can effectively prevent the initiation of an enhanced project by refusing to accept the risks and expenses associated with a joint EOR venture. The magnitude of this problem was not determined, but it could be reduced through

compulsory unitization statutes if it proved to be a serious block to EOR operations.

- Proposed regulations being promulgated by the Environmental Protection Agency (EPA) pursuant to the Safe Drinking Water Act could adversely affect EOR development. These proposed regulations cover injection of materials into the ground. Many producers believe the proposed regulations will significantly restrict or hinder enhanced recovery of oil.

Method of Analysis

Data Base

This assessment of EOR potential is based on a reservoir-by-reservoir analysis of the anticipated performance of EOR processes. The data base for the analysis comprises 385 fields (835 reservoirs) in 19 States, and includes the 245 onshore reservoirs used in recent studies of EOR potential published by the Federal Energy Administration (FEA) and the National Petroleum Council (NPC). The 385 fields used in the OTA assessment include 24 offshore fields (372 reservoirs) and contain 52 percent of the known remaining oil in place (ROIP) in the United States. Results obtained from the data base were extrapolated on a State-by-State basis to obtain national totals. Alaskan reservoirs were not analyzed because there was not enough cost data on EOR operations in a hostile environment.

Technical Screen

Five EOR processes were examined for technical applicability to each reservoir in the data base:

- in situ combustion,
- steam injection,
- CO₂ miscible flooding,
- surfactant/polymer flooding, and
- polymer-augmented waterflooding.

Physical properties of each reservoir were compared with a set of technical criteria based on an assessment of current technology and expected technological advances. In the first stage in the analysis, a reservoir could qualify for more than one process. Reservoirs representing about 76 billion barrels of oil remaining in place (when

extrapolated for the Nation) were determined to be unsuited for any known EOR process because of physical properties of the reservoir.

Economic Screen

Reservoirs that qualified for one or more EOR process during the technical screening were then analyzed to determine the amount of oil that would be produced and the rate of return that would result at various oil prices for each applicable process. Where reservoirs qualified for more than one EOR process, the results of this analysis were compared for each acceptable process. Because the purpose of the assessment was to determine the maximum amount of oil that could profitably be produced under various economic conditions, the process selected for each reservoir was the one which yielded the greatest ultimate oil recovery. In cases where none of the five processes could show a 10-percent return from a given reservoir at the world oil price, the procedure was repeated at the alternate fuels price of \$22 per barrel. Reservoirs that did not yield 10 percent for any process at the alternate fuels price were assigned to the process that appeared to have the best economic chance, or were dropped from consideration if no economic development seemed likely.

Rate of Initiation of EOR Projects

Because worldwide oil supplies may be limited starting in the 1980's, the daily rates of production that are possible with EOR operations between 1985 and 2000 may be more important to national energy policy than the ultimate potential

production. However, the potential production rates are more difficult to estimate than ultimate oil production because the rates depend on the pace of technological development and the speed with which investors are willing to initiate EOR projects. Initiation of EOR projects depends on availability of capital, willingness of investors to accept high risks of new and relatively untested technologies, and the availability of more attractive investment opportunities. Because an analysis of the likely rate of investments in EOR was beyond the scope of this assessment, OTA postulated that EOR projects would become economically acceptable as investment risks decreased. Under this assumption, high potential rates of return (30 percent in 1977) would be needed in the early years of EOR development to compensate for the high risks of EOR projects; as field experience reduces investment risk, lower rates of return (10 percent in 1989) would become attractive.

Cases Examined

Estimates of the technical and economic performance of each EOR process were based on an optimistic but realistic forecast of technological

advances. Such technological advances are expected to result from an ambitious research and development program involving many field tests supported by basic research. Incorporating a postulated schedule of technology advancement, each EOR process was analyzed using high and low estimates of process performance. The resulting high- and low-process performance estimates represent OTA's judgment of the likely range of uncertainty in EOR potential. No attempt was made to determine the most probable value within this range.

Each case was evaluated at three oil prices (using constant 1976 dollars): FEA's upper tier price of \$11.62 per barrel, the current world oil price of \$13.75 per barrel, and an alternate fuels price of \$22 per barrel, at which petroleum from coal might become available. The effects of higher costs for injection chemicals, of air quality standards, and of a slower than anticipated rate of investment-risk reduction were determined for the high- and low-process performance cases. In addition, the effects of a set of price, tax, and leasing options were determined by using a sample of reservoirs representing about 25 percent of the data base reservoirs that qualified for an EOR process.

Oil Recovery Potential

Estimates of the amount of oil that can be recovered using enhanced methods must be interpreted with caution. Enhanced methods, except for thermal processes, have not been extensively field tested. The Office of Technology Assessment assumed that results obtained from controlled laboratory experiments and carefully conducted field tests were representative of what would happen in each of the 835 reservoirs in the OTA data base. The uncertainties inherent in this assumption must be considered when evaluating OTA's estimates of EOR potential. By means of reviews of existing field and laboratory EOR data, specific reservoir characteristics, petroleum engineering principles, and reservoir mechanics, OTA has attempted to develop oil recovery estimates that are realistic. The major uncertainties in these estimates are identified and, where possible, are included in the analysis.

Ultimate Oil Recovery

Proved oil reserves are defined as oil that can be produced with current technology under specified economic conditions (usually current costs and prices). Consequently, estimates of potential additions to proved reserves resulting from the application of EOR techniques vary with the price of the oil. The results of OTA's analysis are summarized in table 1.

At the FEA upper tier price of \$11.62 per barrel, the likely range for EOR production is 8 billion to 21 billion barrels, depending on process performance. The results represent an increase in proved and indicated reserves from primary and secondary production of between 23 and 60 percent.

At the FEA upper tier price of \$11.62 per barrel, the likely range of EOR production is 11 billion to 29

Table 1
Estimates of Ultimate Recoverable Oil and Daily Production Rates From EOR:
Advancing Technology Case With 10 Percent Minimum Acceptable Rate of Return

		Price per barrel	Ultimate recovery ^a (billions of barrels)	Production rates (millions of barrels/day)		
				1985	1990	2000
High-process performance	Upper tier:	\$11.62	21.2	0.4	1.1	2.9
	World oil:	\$13.75 ^a	29.4	1.0	1.7	5.2
	Alternate fuels:	\$22.00 ^b	41.6	1.3	2.8	8.2
		\$30.00	49.2	^c	-	-
	More than	\$30.00	51.1	-	-	-
Low-process performance	Upper tier:	\$11.62	8.0	0.4	0.5	1.1
	World oil:	\$13.75	11.1	0.5	0.7	1.7
	Alternate fuels:	\$22.00	25.3 ^c	0.9	1.8	5.1

^a\$13.75 is the January 1977 average price (\$14.32 per barrel) of foreign oil delivered to the east coast, deflated to July 1, 1976.

^b\$22.00 per barrel is the price at which the Synfuels Interagency Task Force estimated that petroleum liquids could become available from coal.

^cThese figures include 2.7 billion barrels from enhanced recovery processes that are included in the API estimates of proved and indicated reserves.

^dProduction rates were not calculated for oil at prices of \$30 per barrel or higher.

billion barrels, representing a 31- to 83-percent increase in proved and indicated reserves from primary and secondary production. Increasing the price to the alternate fuels price of \$22 per barrel yields a range of 25 billion to 42 billion barrels, an increase of 71 to 120 percent in proved and indicated reserves.

The high-process performance case was used to estimate the amount of oil that could be economically produced at a price of \$30 per barrel. This increase in price might yield an additional 7 billion barrels, a 17-percent increase over the 42 billion barrels estimated to be available at \$22 per barrel in the high-process performance case. The 49 billion barrels that might be recoverable at \$30 per barrel represent about 96 percent of the 51 billion barrels technologically recoverable (assuming high-process performance) with no economic constraints. While it is possible that new technologies with greater recovery potential could be developed if oil prices rose as high as \$30 per barrel, it is not likely that this would occur before the end of this century; this possibility would therefore not significantly affect the policy implications of this assessment.

Rate of Oil Production

Current (mid-1977) oil production from known reservoirs using conventional techniques in the United States is about 8 MMBD. Daily oil produc-

tion is expected to decline to about 7.5 MMBD by 1980, including production from Alaska's Prudhoe Bay; by 1990 production could be as low as 4.2 MMBD. This assessment indicates that EOR has the potential of significantly reducing the decline in domestic production from known reservoirs, particularly after 1990, if investors initiate EOR projects on the schedule assumed in this analysis. It is anticipated that EOR could add between 0.4 MMBD and 1.3 MMBD to domestic production by 1985. The lower figure represents low price (\$11.62 per barrel) and low-process performance, while the upper figure reflects a higher price (\$22 per barrel) and high-process performance. At the current world oil price (\$13.75 per barrel) the range would be 0.5 MMBD to 1.0 MMBD.

The potential contribution to domestic production could increase rapidly after 1985. By 1990, the extremes of potential production are estimated to be 0.5 MMBD and 2.8 MMBD, with a range of 0.7 MMBD to 1.7 MMBD at the world oil price. By the year 2000, possible production could be as low as 1.1 MMBD or as high as 8.2 MMBD. This higher rate of potential production exceeds the current rate of domestic oil production using conventional techniques.

Major Uncertainties

Enhanced oil recovery methods represent a developing and relatively unproven technology.

For example, the two processes which represent over half of the total EOR potential—CO₂ miscible flooding and surfactant/polymer flooding—have received only limited field testing. Consequently there are many uncertainties that must be considered when interpreting the results of assessments of the potential of EOR. The following is a brief discussion of the major areas of uncertainty.

Resource Availability and Process Performance

There is an uncertainty of 15 to 25 percent (or more) in the amount of oil remaining in reservoirs after primary and secondary recovery. In addition, there is uncertainty about the fraction of the remaining oil that can be recovered by an EOR process even after the process has been successfully pilot tested. Analysis of the low- and high-process performance cases shows that a relatively small reduction in process performance can lead to a much larger reduction in potential EOR production; a 12- to 30-percent reduction in the amount of oil recovered (depending on the process) produces a 64-percent reduction in ultimate production at \$22 per barrel, and a 163-percent reduction at \$13.75 per barrel. Similar reductions result for the 15- to 25-percent uncertainty in remaining oil. This disproportionate effect occurs because a relatively small decrease in expected production can reduce the rate of return from many reservoirs to below the 10 percent needed to make EOR operations an attractive investment.

Availability and Cost of Injection Materials

The OTA estimates of EOR potential presume the availability of large quantities of injection materials. Limitations in availability and/or increases in real prices above the levels assumed in this analysis could significantly reduce both the ultimate oil recoverable by EOR methods and the rate at which EOR oil might be produced. The most important materials in this regard are CO₂, surfactant, and fresh water.

The CO₂ miscible process, which is expected to provide between 41 and 51 percent of the total potential EOR production, requires extremely large quantities of CO₂. Production of 13.8 billion barrels of oil (estimated for the high-

process performance case at \$13.75 per barrel) would require a total of about 53 trillion cubic feet (Tcf) of CO₂, a volume nearly three times the annual consumption of natural gas in the United States. The estimates of the production potential of the CO₂ miscible process are based on the assumption that most of the CO₂ would be provided from natural deposits. Natural CO₂ can be delivered to reservoirs by pipeline at lower cost (from about \$.60 to \$.90 per thousand cubic feet (Mcf)) than manufactured CO₂ delivered by truck (on the order of \$2.75 per Mcf). The Energy Research and Development Administration (ERDA) is currently conducting a study of the availability of natural CO₂ for use in EOR. However, even if deposits of sufficient magnitude are found, it is possible that the CO₂ would be sold at prices considerably above the production costs assumed in this study. Higher costs could significantly reduce the amount of oil economically-recoverable using the CO₂ miscible process. For example, a 50-percent increase in price of CO₂ could reduce the potential production from the CO₂ miscible process by 49 percent, from 13.8 billion to 7.1 billion barrels (\$13.75 per barrel and high-process performance).

Chemical costs are also important variables in the surfactant process, the EOR process which OTA estimates might provide 13 to 34 percent of the ultimate EOR production. This process is extremely sensitive to the costs of the injection chemicals (surfactant and polymer) used. A 50-percent increase in price of surfactants and polymers over the level assumed in this study would practically eliminate the potential of this process at the world oil price, reducing production in the high-process performance case from 10.0 billion to 0.2 billion barrels. However, this oil could eventually be produced at the alternate fuels price, with an ultimate recovery of an estimated 9 billion barrels.

The final critical injection material is water. While secondary oil production (waterflooding) already requires significant quantities of water, existing EOR methods require relatively fresh water. Availability of fresh or nearly fresh water could ultimately constrain EOR development, because EOR processes have a large potential in Texas, western Louisiana, and California—areas

where water shortages already exist and are predicted to be more severe by the year 2000. Achievement of the full potential of EOR will require the development of means for using water of higher salinities in EOR processes.

Rate of Investment in EOR Projects

As noted, OTA's estimates of the potential daily production from EOR processes are based on the assumption that EOR projects will be initiated according to a postulated schedule related to expected rates of return. However, difficulties in forecasting actual investor behavior suggest that the estimates of daily production rates are less certain than the estimates of ultimate oil recovery. Enhanced oil recovery investments will have to compete for funds with other investment opportunities. Enhanced oil recovery processes are relatively new, and the investment risk is high compared to more familiar oil exploration and production methods. The oil industry may therefore be reluctant to invest large amounts of capital in EOR processes in the next few years, which would delay the production of oil by means of enhanced recovery methods.

Marketability of Heavy Crudes

Market constraints could limit the development of thermal methods in California where the market for the heavy crudes is limited primarily because heavy oil requires more processing than lighter oils. Crude oil from Prudhoe Bay may further reduce the market for California heavy

crude for a short period. A real or perceived weak market for heavy oils produced by thermal methods in California will be a deterrent to thermal EOR development in that State. This delay may well be temporary, but it could result in lower rates of oil production from thermal EOR methods in the 1980's than those estimated in this report.

Combinations of Uncertainties

The effects of uncertainties have been evaluated independently. Reductions in ultimate recovery and/or changes in timing of production resulting from altered assumptions in each of these uncertain areas are presented above and in more detail in chapter III. Changes in ultimate recovery or timing of production have not been evaluated for combinations of uncertainties. It is possible that two or more uncertainties could simultaneously reduce EOR potential. In fact, it is remotely possible that resource availability could be lower than expected, low-process performance prevail, supply of injection materials be constrained or costly, and EOR investments remain relatively risky—all at the same time. Should this occur, EOR potential would be very low, and EOR production would never make a significant contribution to national production.

The Office of Technology Assessment does not believe this combination of circumstances is likely. The lower bounds presented in this study represent a more realistic estimate of the minimum production which could be expected from EOR techniques.

Impact of Price and Tax Policies

Price

The OTA analysis has assumed that the price being tested would apply only to the increment of production from a well that could be directly attributed to the EOR process, while oil being produced by primary and secondary methods from the same well would continue to receive the price for which it is qualified under current price control regulations. The same assumption was used in independent analyses of EOR potential conducted for FEA and ERDA.

Both the amounts and timing of potential EOR production are sensitive to the price that will be received for the oil. In both the low- and high-process performance cases, the two possible price increases considered (\$11.62 per barrel to \$13.75 per barrel and \$13.75 per barrel to \$22 per barrel) produced more than proportional increases in potential recovery. Increases in price had an even greater effect on the rate at which EOR production might be brought on-line.

In 1976, Congress amended the Emergency Petroleum Allocation Act to provide additional price incentives for bona fide "tertiary enhanced recovery" (EOR) techniques. Since then, FEA has published proposed regulations and has held public hearings on price incentives for oil produced by enhanced techniques. In addition, the President recommended decontrolling the price of EOR oil in his National Energy Plan.

The effects of decontrol of oil produced by EOR methods were tested using a sample of about 25 percent of the OTA data base reservoirs that technically qualified for an EOR process. Impacts of decontrol depend primarily on investor expectations about the future market price of oil. It was assumed that investors expected the real price of oil to rise at an average annual rate of 5 percent. With this assumption, more reservoirs could be profitably developed (34 percent more in the sample) with prices decontrolled than if prices were held at a \$13.75 constant real price. At the same time, decontrol would significantly decrease the risk for investors in all EOR processes except in situ combustion. Decontrol of oil price was more effective at stimulating development than any of the other price and tax options considered. As long as investors expect the market price of oil to rise, decontrol will reduce the risk of EOR investments compared to a controlled-price policy.

The OTA analysis presumes that oil produced by EOR operations will be priced differently from oil produced by primary and secondary methods from the same well at the same time. The Federal Energy Administration proposed the same approach in applying price incentives for EOR production. This policy creates the problem of deciding what fraction of total oil production should be attributed to EOR when primary and secondary methods are being used at the same reservoir. The challenge is to define this increment in such a way as to encourage the application of EOR processes without significantly distorting decisions concerning primary and secondary production.

The FEA proposal involves case-by-case judgments concerning the production that would normally be expected using primary and secondary methods. But that proposal raises questions

about whether the technical expertise for making such decisions would be available at the Federal and/or State levels. An alternative approach, supported by industry in comments on FEA's pricing proposals, would be to apply the same price incentives to all oil produced from a field to which an EOR process was applied. While this would avoid the problem of defining EOR incremental oil, it would leave the problem of defining the level of effort required for a project to qualify as a bona fide EOR process, and would require monitoring to ensure that the effort is maintained.

A more detailed analysis of the advantages and disadvantages of these and other incentive pricing options was beyond the scope of OTA's assessment of the potential contribution of EOR processes to national reserves. Because of the importance and complexity of the associated issues, Congress may wish to examine the problem of defining and monitoring EOR operations, and possibly hold oversight hearings on the proposed FEA pricing regulations for EOR production. If defining EOR incremental oil production and monitoring EOR operations are found to be critical issues, a mechanism could be developed whereby bona fide EOR projects could be certified and monitored. Certification and monitoring of EOR operations could be performed by the operator, a State regulatory group, a Federal agency, or a combination of State, Federal, and producer interests.

Special Tax Treatment for EOR Projects

The impacts of several tax incentives for EOR investments were analyzed at the world oil price. The options included an increase in the investment tax credit from 10 to 12 percent, accelerated depreciation, and an option in which injection costs were depreciated over the life of the project rather than treated as expenses during the year they were incurred. Neither the investment tax credit nor accelerated depreciation had much effect on the development of reservoirs using EOR methods. On the other hand, a requirement that injection costs be depreciated rather than treated as expenses led to a large decrease (29 percent) in total production. Depreciating rather

than expensing costs of injection materials could greatly inhibit the development of the surfactant and CO₂ miscible processes, which have the potential of providing well over half of the total EOR production at prices at or above \$13.75 per barrel.

Price Guarantees and Subsidies for EOR Production

Three forms of explicit and implicit subsidies were evaluated: a price guarantee at \$13.75 per barrel; a 15-percent subsidy of EOR investment costs (excluding costs of injection materials); and a \$3 per barrel price subsidy of EOR oil. The effectiveness of a price guarantee depends almost entirely on the probability that the world market price of oil will decline below the current level in real terms. Assuming that this probability is quite low, a \$13.75 per barrel price guarantee would probably have little effect on the risk of EOR investments. The 15-percent investment subsidy also exhibited little impact on risk or on potential production, although its effects might be somewhat greater than the tax options that were considered.

A \$3 per barrel price subsidy would be more effective than the tax and subsidy options analyzed, and could result in a 6-percent increase in ultimate EOR production and substantially reduce the risk to investors. Because the cost of the subsidy would be offset to some extent by increased Government tax revenues from increased production, the actual cost of the subsidy would be somewhat less than \$3 per barrel.

Alternative OCS Leasing Systems

Because a large part of future oil discoveries are expected to be on the Outer Continental Shelf (OCS), the effects of several OCS leasing policies were tested on a 25-reservoir sample of the 294 offshore reservoirs in the OTA data base which were amenable to EOR processes. The United States currently uses, almost exclusively, a cash-bonus bidding system in which exploration and development rights on an OCS tract are granted to the group offering the highest front-end payment, or bonus bid. In addition to the

cash bonus, a 16.7-percent royalty on gross production is collected by the Government. The preceding analysis of policy options assumed that this method would be in use for the offshore CO₂ cases.

Recent discussions of alternate leasing systems have included proposals for greater use of contingency payments (royalties or profit shares, which collect Government revenue based upon the value of actual production), which are intended to reduce front-end capital requirements and shift a greater share of risk to the Government. The impacts on EOR production potential of two such systems were analyzed by OTA: cash bonus plus a 40-percent royalty, and a cash bonus plus a 50-percent net profit share. The 40-percent royalty was shown to increase the investment risk and to make some fields uneconomic for EOR, a result that confirms earlier studies of the impact of high royalties on primary and secondary OCS production. While the profit-share system did not eliminate any fields from consideration, it did tend to increase the risk of EOR investments and could therefore tend to delay EOR implementation. This is contrary to previous results on primary and secondary production, and suggests that a profit-share rate of 50 percent would be too high for EOR development on marginal fields.

A possible option would be the use of a variable-rate royalty or profit-share approach, in which rates would automatically be reduced for marginal fields. Alternatively, the contingency payment could be waived when that became necessary to enable further production, a provision included in proposed amendments to the Outer Continental Shelf Lands Act (S.9 and H.R. 1614). While this option was not tested directly, the \$3 per barrel price subsidy approximates the removal of the 16.7-percent royalty at an oil price of \$13.75 per barrel. The \$3 per barrel price subsidy increased the number of offshore reservoirs in which EOR methods might be economical. These results may somewhat exaggerate the possible effect of eliminating the royalty because the \$3 per barrel subsidy is about 30 percent greater than the current 16.7-percent royalty on \$13.75 per barrel oil, and because the policy sample of reservoirs contained a higher proportion of marginal fields which would be more affected than the entire data base.

Legal Issues

To identify potential legal obstacles to EOR, questionnaires were sent to oil producers and to State and Federal regulatory authorities, and a study was made of pertinent laws, treatises, special reports, and periodical literature. The most significant existing or potential legal constraints identified were Federal price controls on crude oil, weakness or absence of compulsory unitization statutes in several crucial States, and existing and proposed environmental protection regulations. These legal constraints have an impact on secondary (waterflood) methods as well as on EOR.

The issue of price controls and alternative pricing policies has been discussed in an earlier section. The second legal constraint involves unitization, the joining of interest holders in a reservoir for the purpose of sharing the costs and benefits of an efficient development plan for the reservoir as a whole. Unitization is usually desirable; it often would be essential to make application of secondary and enhanced recovery techniques to a reservoir possible. Most producing States provide for compulsory joinder of interest owners in a unit once a certain percentage of interest holders have agreed to unitization. In the absence of such legislation, or where the necessary percentage of voluntary participation cannot be achieved, secondary and enhanced recovery operations can result in substantial liability for the operator if nonjoiners suffer damage.

While most States have compulsory unitization statutes, Texas does not, and the statutes in California are so limited as to be rather ineffective. These States together represent about half of the total national EOR potential, and the difficulties of forming unit agreements may therefore be a significant obstacle to large-scale development of EOR production. A field-by-field analysis of ownership patterns is needed to determine whether difficulties with unitization might prove to be a major obstacle to the development of a significant fraction of EOR potential. Such an analysis was beyond the scope of this study.

If unitization problems were found to be serious constraints on EOR production, several actions could be considered. The Federal Government could recommend that each State adopt a statute that makes unitization compulsory when 60 percent of the working interest and royalty owners consent to unitized operations. The Federal Government could also recommend that the States adopt statutes to exempt producers from liability for any damages caused by State-approved enhanced recovery operations not involving negligence on the part of the producer. This would remove a significant constraint to unit operations in the absence of full participation by all the interest owners. Finally, the Government could require that States have appropriate compulsory unitization statutes in order to qualify for Federal administrative support, or to avoid having a Federal agency become responsible for unitization and enhanced recovery regulation.

The primary environmental regulatory constraints on EOR relate to air quality standards in California and EPA's proposed regulations under the Safe Drinking Water Act to control underground injections. Current Federal and State environmental regulations under the Clean Air Act limit total emissions in California to the pollution levels which existed in 1976. Therefore, use of additional steam generators and air compressors for thermal recovery operations in California may be significantly constrained. Using existing generators and compressors, the maximum increase in the production rate from thermal methods in California (the area where thermal processes have the greatest potential) will probably be no more than 110,000 barrels per day, about half of the estimated 1990 potential rate of production at the world oil price. Expansion of thermal production will require application of emission control technology capable of meeting air quality standards.

The Safe Drinking Water Act, passed in 1974, directs EPA to issue regulations to control underground injection of fluids that may threaten the

quality of water in aquifers that are or may be used for public water supply. The act specifically provides that requirements in these regulations must not interfere with or impede any underground injection for the secondary or tertiary recovery of oil or natural gas unless such requirements are essential to ensure that underground sources of drinking water will not be endangered by such injection. However, reaction to EPA's proposed regulations by such groups as the Interstate Oil Compact Commission, the American

Petroleum Institute, individual oil producers, and others indicate that the regulations are perceived as likely to have an adverse impact on enhanced recovery operations. Because EOR processes are expected to pose no greater threat to drinking water than waterflooding, which has a good safety record, Congress may wish to hold oversight hearings to determine if the proposed regulations would unduly inhibit the application of EOR techniques.

Environmental Effects

In general, the environmental impacts of EOR operations are not expected to be significantly different in type or magnitude than those from primary and secondary oil production activities. The major differences are air emissions from thermal processes, and increases in consumption of fresh, or relatively fresh, water.

Thermal EOR processes produce atmospheric pollutants from the combustion of large quantities of oil, either in steam generators (the steam injection process) or in the reservoir itself (the in situ combustion process). These types of emission are likely to have localized impacts and are expected to be highly significant in areas that are already in violation of Federal ambient air quality standards. Air quality standards are expected to limit expansion of thermal processes in California unless effective emission control devices are

used or compensating reductions in emissions are made elsewhere in the affected area.

As noted in the discussion of resource constraints, EOR processes in general required significant quantities of fresh, or relatively fresh, water, whereas secondary waterflooding can use saline water. This consumption of fresh water not only will compete directly with domestic, agricultural, and other industrial uses, but also could result in a drawdown of surface water, which could, in turn, severely affect aquatic flora and fauna in the area of the drawdown. However, this impact usually would be localized and of short duration. The consumption of fresh water by EOR processes has the greatest potential impact in California, Texas, and western Louisiana, where water supplies are limited. Development of EOR technologies to allow use of saline water could reduce this potential problem.

THE POTENTIAL AND ECONOMICS
OF
ENHANCED OIL RECOVERY

FINAL REPORT

APRIL 1976

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WITH
OFFICE OF REGULATORY POLICY
OFFICE OF POLICY
FEDERAL ENERGY ADMINISTRATION

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EXECUTIVE SUMMARY

THE PURPOSE

Domestic petroleum production in the United States is in steady decline. Proved reserves are shrinking as production outstrips new discoveries and expansions, while demand for petroleum products continues to rise in the improving economy.

Imports, already providing nearly one-half of total demand, continue to rise, with substantial amounts of these imports coming from OPEC nations. Alternative energy sources are under development, but will not be available in the near-term. In light of these circumstances, pressures to decrease near-term dependency are high. One promising step toward reduced reliance on imports is to improve the efficiency of domestic production through the use of advanced recovery techniques.

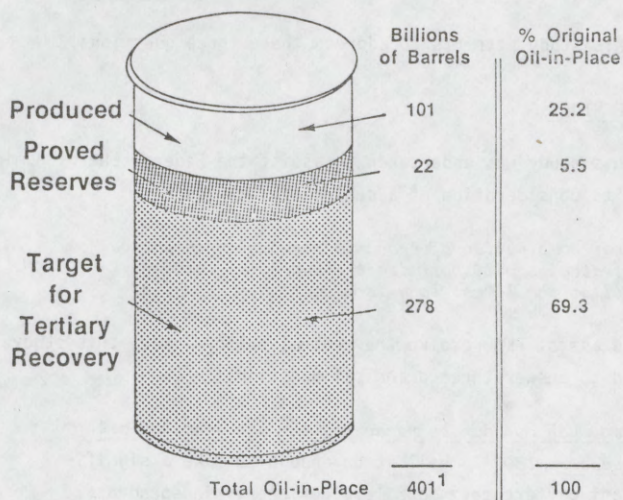
After conventional (primary and secondary) production is depleted, substantial quantities of oil remain in existing, developed oil fields. Until recently, most of this oil was regarded as impossible or uneconomic to recover.

As depicted in Exhibit 1, this unrecovered oil amounts to almost 70 percent of the original oil-in-place. New developments in technology and the rise in world oil prices, however, give promise that substantial portions of this otherwise neglected oil can be recovered. These new technical developments fall under the broad heading of enhanced oil recovery (EOR).¹

¹The terms "tertiary" and "enhanced" are used interchangeably in this text. They are used as shorthand for the newer "exotic" recovery methods and do not include the more conventional production enhancement methods of waterflooding, pressure maintenance, or cyclic steam. For purposes of this study, EOR includes steam drive, in situ combustion, carbon dioxide miscible flooding, surfactant/polymer flooding, and polymer augmented waterflooding. Hydrocarbon miscible processes would be included in our definition of EOR but are not analyzed in this report because they are generally seen as uneconomic in the future. In terms of timing of usage, these exotic techniques may be used either after primary recovery or after traditional enhanced recovery; thus being used either in a secondary or tertiary production time phase.

EXHIBIT 1

Production, Reserves, and Residual Oil-in-Place—U.S. Onshore, Except Alaska



¹The Comparable Figures for the Total U.S., Including OCS Are:

- Produced—106 Billion Barrels
- Proved Reserves—34 Billion Barrels
- Remaining 300 Billion Barrels Oil-in-Place

The Federal Government can significantly influence the pace at which this new technology is adopted. Judicious Federal policy, however, requires answers to three central questions: how much enhanced oil can be made available; when will it be available; and at what cost?

This study attempts to address these three questions.

FOCUS OF THE STUDY

This study was undertaken to assist the Federal Energy Administration in its consideration of a central policy issue:

What combination of economic regulation/incentive strategies will optimize the supply of tertiary oil at the lowest long-term cost to the public?

To assist FEA resolve the central policy issue, this study was designed to answer three principal questions:

1. How much oil can be recovered through enhanced oil recovery (EOR)? Will it be enough to make a significant difference in our level of energy independence?
2. How soon will it be proved as reserves and how soon will it be produced? Will it make a difference during the period while the U.S. is most vulnerable to another energy crisis?
3. Most importantly, how much will it cost? Can this nation afford to follow this route in approaching self-sufficiency?

THE SITUATION

The portion of the remaining oil that will be recovered through enhanced oil recovery and the rate of production are the subjects of considerable controversy. Predictions of six firms and estimates of four studies (Exhibit 2) demonstrate the magnitude of the differences of opinion. Such differences reveal the basic challenge in analyzing potential tertiary recovery -- no consensus exists as to the amount and timing of the additional oil recovery.

Though the optimistic outlook of the early 1970's toward EOR has clouded somewhat, there is little cause for the pessimism reflected in certain of the projections noted in Exhibit 2. EOR production already provides nearly 240,000 barrels per day. Under very conservative assumptions, EOR production should provide 470,000 barrels per day within the next two or three years. This most conservative estimate of near-term production includes only acreage already developed, new (1976) starts already in process, and the conversion of existing cyclic steam projects to steam drive. While many of the better EOR prospects may well be underway, a judicious set of Federal policies for expanding domestic oil supply and an aggressive response by the industry should be able to significantly improve upon this base case.

SUMMARY OF ONGOING/PLANNED EOR PROJECTS						
EOR TECHNIQUE	ONGOING		PLANNED/CONVERSIONS		TOTAL	
	Acre	B/D	Acre	B/D	Acre	B/D
1. STEAM	13,658	106,876	27,228	214,925	40,885	321,801
2. IN SITU COMBUSTION	3,984	7,581	1,164	2,212	5,148	9,793
3. CO ₂ /HYDROCARBON MISCIBLE	81,925	113,500	7,100	10,000	89,025	123,500
4. SURFACTANT/POLYMER	758	530	189	132	947	662
5. POLYMER/CAUSTIC	<u>13,045</u>	<u>7,442</u>	<u>8,142</u>	<u>4,843</u>	<u>21,187</u>	<u>12,285</u>
Total Barrels/Day From EOR		235,929		232,112		468,041

EXHIBIT 2
ESTIMATES OF EOR POTENTIAL

	Potential EOR Reserves (billions of barrels)	Production By Date (millions of barrels/day)
1. <u>Oil Companies</u>		
1	15	-
2	-	1.0 by 2005
3	25	0.5 by 1985
4	18	0.75 by 1985
5	110	1.0 by 1985
6	25	1.0-2.0 by 1990
2. <u>Other</u>		
• FEA/PIB ¹ (74)		
-- 5AU (\$11)	57	1.8 by 1985
-- AD (\$11)	"	2.3 by 1985
• FEA ² (74)		
-- (\$12-13)	65	-
• FEA/Energy Outlook ³ (76)		
-- (\$12)	-	0.9 by 1985
• EPA ⁴	15-25	-

1. Project Independence Report, Federal Energy Administration, November 1974.
2. Review of Secondary and Tertiary Recovery of Crude Oil, Lewin & Associates, Inc. for FEA, June 1975.
3. 1976 National Energy Outlook, Federal Energy Administration.
4. The Estimated Recovery Potential of Conventional Source Domestic Crude Oil, Mathematica, Inc. for the U.S. Environmental Protection Agency, May 1975.

STRUCTURE OF THE ANALYSIS

The differences in the projections result from a lack of accepted, precise terms or measures for communicating expectations of EOR potential, the variety of price assumptions used by various studies, and the divergent methodologies used for addressing these questions. Rather than add yet one more highly aggregated, national level pronouncement of the potential of EOR, this study adopted a new, detailed, and more explicit approach.

In brief, the methodology used in this study follows an engineering and micro-economic approach that emulates -- on a slightly broader scale -- the actual decision behavior of the companies that will bring tertiary recovery to fruition. Exhibit 3 outlines the seven-step approach used in the analysis. These seven basic steps are discussed briefly below.

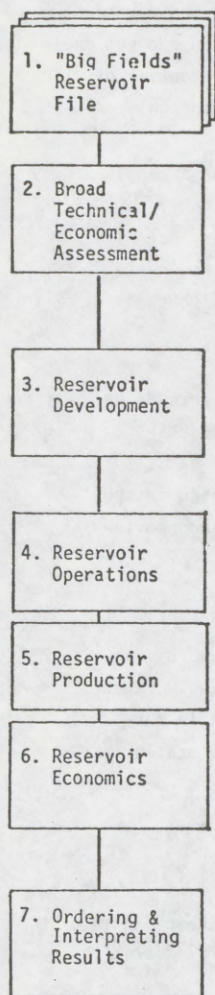
Step 1. The Reservoir File. The current analysis focuses on the major oil fields in the three largest "lower-48" crude producing states -- California, Louisiana, and Texas. According to API data, these three states collectively contain 64% of the oil remaining in the "lower-48" states (after primary and secondary recovery) -- and provide the major target for tertiary recovery.

In all, 245 reservoirs in 175 fields were analyzed. We estimate that these 175 fields contain 60% of all the remaining oil-in-place in California, Louisiana (onshore), and Texas. Accordingly, these reservoirs were felt to be representative of the three states in the study, but not necessarily representative of the remaining 45 states.¹ Thus, our findings are projected to totals for the three states but not overall for the nation.

¹This is due to certain idiosyncrasies in the reservoirs of these states, e.g., the heaviness of California crudes, the fractures and salinity of Louisiana reservoirs, or the vast carbonate reservoirs of Texas.

EXHIBIT 3

STRUCTURE OF THE ANALYSIS



RESERVOIR DESCRIBED BY:

- Reservoir characteristics
- Fluid characteristics
- Production history
- Original & remaining oil in place

RESERVOIR ASSIGNED TO:

- No EOR method applicable
- EOR development by
 - steam drive
 - in situ combustion
 - CO₂ miscible flood
 - surfactant/polymer flood
 - polymer waterflood

RESERVOIR DEVELOPED FOR EOR TECHNIQUE:

- Estimated start time & pace
- Phases of development
 - detailed study & planning
 - technical pilot
 - economic pilot
 - field-wide, phased expansion
- Costs of development

RESERVOIR OPERATING IN EOR TECHNIQUE:

- Costs of operation
- Costs of injected materials
- Timing of injection

RESERVOIR PRODUCES EOR OIL:

- Amount of production
- Rate of production for each development phase

RESERVOIR COSTS & PRODUCTION TOGETHER YIELD:

- Price necessary at required rate of return
- Rate of return at set prices
 - upper tier
 - lower tier

AGGREGATE PROJECTIONS OF:

- Total oil remaining in place where EOR techniques apply
- Potential EOR recovered resources
 - total, independent of price
 - price-supply curve in real price
 - price-supply curve with inflation
 - price-supply curve by technique & state
- Potential EOR reserves
 - total, independent of time
 - rate of "proved" reserves
- EOR recovery
 - total, independent of time
 - rate of recovery over time

For these 245 reservoirs, detailed data were collected concerning formation and fluid characteristics, production histories, original and remaining oil (Exhibit 4). Public documents were used as basic sources. Missing data were estimated using engineering correlations. All data were edited for volumetric consistency, a requirement of later steps in the analysis.

Step 2. Broad Technical/Economic Assessment. The major tertiary recovery methods differ substantially from one another in their applicability to various crude oil and reservoir characteristics. In order to assess the applicability of tertiary recovery to specific reservoirs, an explicit evaluation mechanism was required. For this, a screening guide was developed for five major EOR methods (Exhibit 5). The guide was derived from consultations with acknowledged authorities in the EOR field and from the review and analysis of literature and field reports concerning actual EOR projects.

Each reservoir in the data base was tested for its potential for tertiary recovery. Those reservoirs having high potential for tertiary recovery were identified and assigned to the most suitable recovery technique.

Step 3. Reservoir Development. The third step in the analysis was a simulation of industry decision-making and the pace of development for tertiary recovery projects. This step generates estimates of the costs, financial hurdles, and timing of tertiary development.

Step 4. Reservoir Operation. Well operating and injection costs and the costs of the recovery chemicals and materials were estimated in the fourth step of the analysis.

Step 5. Reservoir Production. Recovery models for each of the five EOR techniques were developed to estimate the quantity and timing of the "proving" of reserves and the production of tertiary oil.

EXHIBIT 4
UNIT/FIELD DATA
(10/8/75)

I. DESCRIPTION

Operator _____
 County _____
 Basin/Province _____
 Geologic System (Age) _____
 Reservoir Type _____
 Unit Name _____

STATE _____

IOR METHOD	Applic. Yes No	Reason
CO ₂		
Hydrocarbon		
Surfactant		
In Situ		
Steam Drive		
Polymer		

Report of (circle) Project Unit Reserv
 Field Name _____
 Formation Name _____
 Reservoir Name _____

II. RESERVOIR CHARACTERISTICS

Salinity - Conn - TDS _____ ppm
 Salinity - Inj - TDS _____ ppm
 Hardness - Calcium _____ ppm
 Hardness - Magnesium _____ ppm
 BH Temperature _____ °F
 Permeability - Range _____ md
 Permeability - Average _____ md
 Pay Thickness - Av Net _____ ft
 Perm. x Thick/Visc. _____
 Porosity _____ % V
 Approximate Dip _____ °
 Solution Gas-Oil Ratio (GOR) _____
 Current Gas-Oil Ratio (GOR) _____
 Formation Volume Factor (Orig) _____
 (Latest) _____

Reservoir Lithology _____
 Primary Drive _____
 Gas Cap (Orig) _____
 (Latest) _____
 Fractures _____
 Conn. Water Saturation _____ %PV
 Pres/Pre-EOR Oil Saturation _____ %PV
 Pres/Pre-EOR Resid. Oil Satur. _____ B/AF
 Gravity _____ °API
 Viscosity _____ cp
 Poros. x Resid. Oil Satur. _____
 Depth (Subsurface) _____ ft
 Satur. (Bubble Point) Pressure _____ psi
 Pressure (Orig.) _____ psi
 (Latest) _____ psi

III. VOLUME/AREA/WELLS

	Unit/Project		Reservoir		Field	
	Total	Latest	Total	Latest	Total	Latest
Rock Volume - AF						
Rock Volume - Bbls						
Pore Volume - Bbls						
Producing Acres						
Producing Wells						
Injection Wells						
Well Spacing - Acres/ Producing Well						

IV. RECOVERABLE OIL & PRODUCTION TO DATE - API Recovery Factor (St/Dist/Lith) _____ %

	Unit/Project		Reservoir		Field	
	Bbl(000)	B/AF	Bbl(000)	B/AF	Bbl(000)	B/AF
ORIGINAL OIL						
-Estimated Orig. Oil-in-Place (OOIP)-(1)						
-Estimated Orig. Oil-in-Place-(2)						
-Estimated Orig. Oil-in-Place-(3)						
TOTAL PRODUCTION (Yr. _____)						
Drive Type		St. Year				
-Primary						
-Secondary						
-Secondary						
-EOR						
-EOR						
CUMULATIVE PRODUCTION						
-% of OOIP-(1)						
-% of OOIP-(2)						
ESTIMATED ULT. RECOVERY						
-% of OOIP-(1)						
-% of OOIP-(2)						
ESTIMATED RESID. OIP at ABANDONMENT						
-% of OOIP-(1)						
-% of OOIP-(2)						

EXHIBIT 5 SCREENING GUIDE

CRITERIA FOR THE APPLICATION OF SELECTED ENHANCED OIL RECOVERY METHODS

SCREENING PARAMETERS	STEAM DRIVE	IN SITU COMBUSTION	CO ₂ MISCIBLE	SURFACTANT/ POLYMER	POLYMER WATERFLOOD
Viscosity -- cp at reservoir conditions	NC	NC	<12cp	<20cp	<200cp
Gravity -- °API (Calif. crudes)	>10° (>10°)	10-45° (10-45°)	>30° (>26°)	>28° (>25°)	>18° (>16°)
Fraction of Oil Remaining in Area to be Flooded (before EOR) -- % PV	50% ¹	50% ¹	25%	25%	50% ¹
Oil Concentration -- B/AF Porosity x Oil Saturation	>500 B/AF >.065	>400 B/AF >.05	NC	NC	NC
Depth -- feet	<5,000*	>500'	>3,000'	NC- (8500')*	NC- (8500')*
Temperature -- °F	NC	NC	NC	<200°F*	<200°F*
Original Bottom Hole Pressure -- psi	NC	NC	>1,500psi	NC	NC
Net Pay Thickness -- feet	>20'	>10'	NC	NC	NC
Permeability -- md	NC	NC	NC	>20 md (with polymer drive)	>20md
Transmissibility (Permeability x Thickness/Visc.)	>100	>20	NC	NC	NC
Natural Water Drive ²	none to weak	none to weak	none to weak	none to weak	none to weak
Gas Cap ²	none to minor	none to minor	none to minor	none to minor	none to minor
Fractures	NC unless extreme	none to minor	none to minor	none to minor	none to minor
Lithology	NC	NC	NC	sandstone only*	NC
Salinity -- ppm TDS	NC	NC	NC	<50,000ppm*	NC
Hardness -- ppm -- calcium & magnesium	NC	NC	NC	<1,000ppm*	NC
COMMENTS	• Porosity x thickness (high) • 10-acre spacing • Economic freshwater available • Economic fuel available • High net to gross pay • Low clay content	• High dip preferred • Porosity x thickness high • 40-acre spacing • Low vertical permeability preferred • Preferred temperature >150 • High net to gross pay	• Thin pay preferred • High dip preferred • Homogeneous formation preferred • Porosity x thickness low • Natural CO₂ availability • Low vertical permeability in horizontal reservoirs	• Homogeneous formation preferred • Low clay content • Porosity x thickness (high) • Prefer water-flood sweep 50%	• Use with or prior to waterflood • Low calcium and clay content • Porosity x Thickness (high)

NC = Not a critical factor

* Considered a constraint under current technology

¹In portion of field to be flooded. Assuming 80% of area of reservoir contains 95% of remaining oil, the oil saturation for the total field becomes 42% of pore volume.

²These criteria apply to reservoirs with substantial remaining primary recovery.

Step 6. Reservoir Economics. The costs and timing for development and operation were combined to: (a) compute the required price per barrel for the incremental enhanced/tertiary production given a series of rates of return; and (b) compute rates of return given a series of prices. Special attention was given to the "lower tier" and "upper tier" prices as adjusted for the crude oil gravity differential.

Step 7. Ordering and Interpreting the Results. The final step was to translate the results into projections of: how much, when, and at what cost.

MAJOR FINDINGS

The approach and methodology described above yielded four major findings for California, Louisiana (onshore), and Texas.

1. Recoverable Resources

Resources technically recoverable through tertiary recovery are estimated at 43.3 billion barrels in the three states. (However, nearly seven and a half billion barrels of produced crude oil would itself be consumed as part of the tertiary oil recovery process. These barrels would be burned for generating steam and compressing air and CO₂, or would be injected as part of the surfactant slug. Thus, the use of substitute fuels and materials could appreciably increase the quantity of tertiary recovery.)

2. Effect of Price on Supply

Price strongly affects tertiary supply.¹ At upper tier prices, assuming a "real" eight percent rate of return,² 30.5 billion barrels of the 43.3 billion barrels of technically recoverable resources will be produced. At lower tier prices, only 5.2 billion barrels will be produced (Exhibit 6).

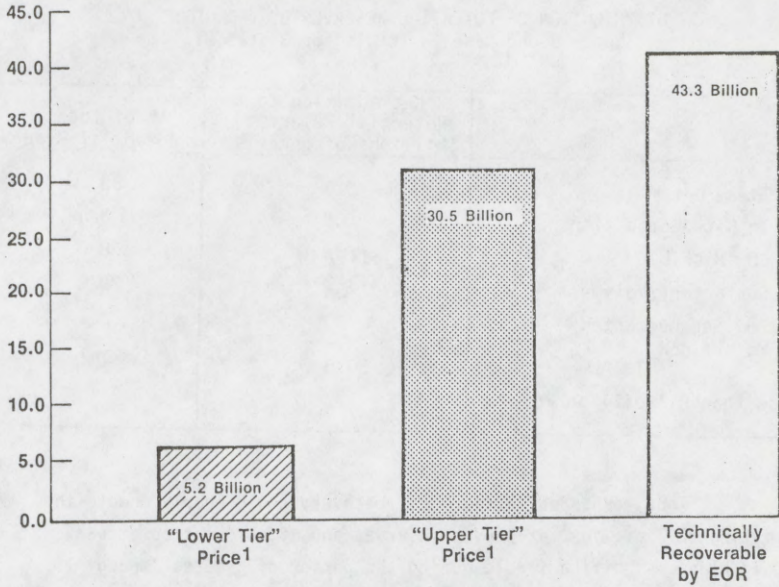
¹Prices are assumed to be real, that is, they would be adjusted directly with cost inflation.

²An 8% real cost of capital is equivalent to 15% return on investment under 7% inflation.

EXHIBIT 6

Sensitivity of Tertiary Reserves to Price
(Total for 3 States)

Billions of Barrels of Potential Tertiary Reserves

¹ Price is Assumed To Be Maintained in "Real" Terms (i.e. Adjusted for Cost of Inflation)

The overall price/supply curves are detailed by state and by EOR technique in Exhibits 7 and 8, at an eight percent real rate of return (15 percent return when adjusted for 7 percent inflation). The contributions of the five techniques are displayed below.

DISTRIBUTION OF POTENTIAL RESERVES BY TECHNIQUE
(Upper Bound Case -- Totals for 3 States)

	Net Addition to Potential Reserves (billions of barrels)	% of Total Potential Reserves
Steam Drive	9.1	30
In Situ Combustion	0.9	3
CO ₂ Miscible	11.7	38
Surfactant/Polymer	8.8	29
Polymer Augmented Waterflood	*	*
TOTAL	30.5	100.0
*Less than 0.1 billion		

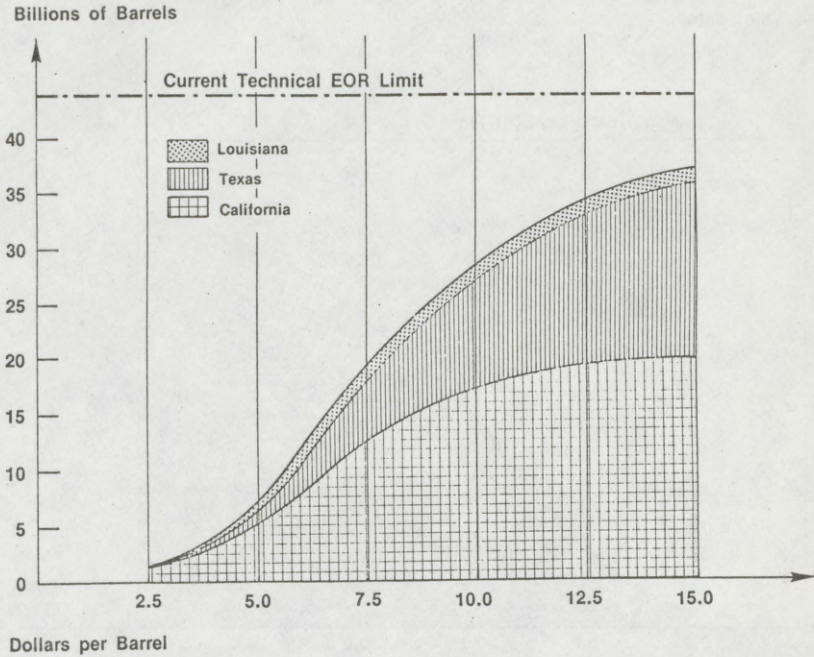
Thus, enhanced/tertiary oil recovery could nearly double the existing 32.7 billion¹ of proved reserves and, if brought on stream, could play a significant role during the period of greatest energy vulnerability.² The remainder of the study findings concentrate on the question of timing -- when can the nation expect tertiary oil to be put into the pipeline.

¹API estimated reserves of crude oil in the United States as of 1/1/76.

²Even with these important additions to the domestic oil supply, the overall domestic energy situation remains one of serious concern. In 1975, U.S. energy consumption was 73 quadrillion BTU's (equivalent to 12 billion barrels of oil). Domestically produced petroleum met only one-fourth, or 3 billion barrels of the total energy demand.

EXHIBIT 7

Projected Cumulative Price—Supply Curve by State



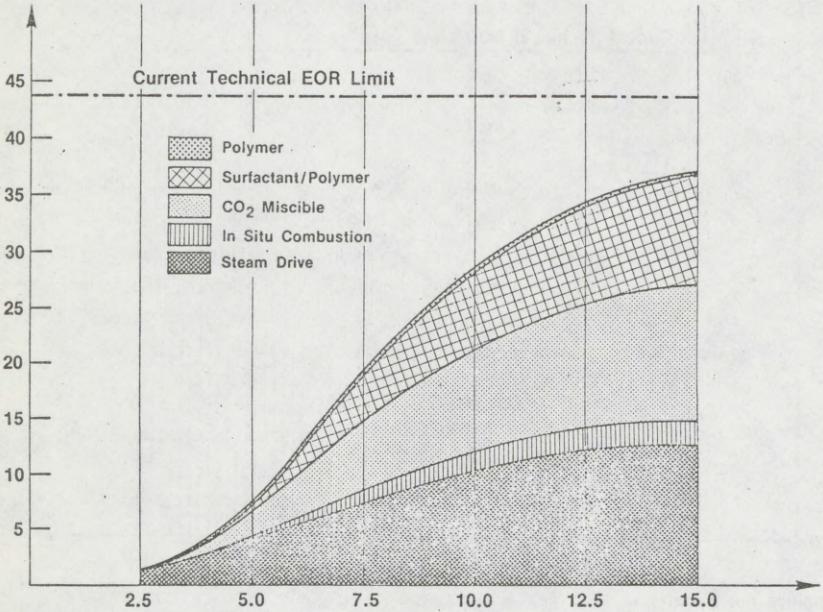
- 14 -

IBIT 8

Projected Cumulative Price—Supply Curve by Technique

(Total for 3 States)

Billions of Barrels



Dollars per Barrel

3. Additions to Proved Reserves

The first step for realizing the potential of tertiary reserves is to "prove" them through a series of technical and economic tests. Thus, the proving of potential reserves is a time-based function which depends not only on technology, but also on a price that will yield an acceptable return on tertiary investment. Using different combinations of time, technology, and rates of return, numerous cases could be developed for making projections of when tertiary oil will be considered proven and produced. Given the bounds of current federal legislative authority the study examined the consequence of three sets of federal initiatives:

- Base Case. This case reflects the anticipated response if prices for tertiary oil are maintained at the lower tier -- \$5.25 per barrel, as adjusted for gravity differential. (For the lower gravity California crudes, however, the lower tier price may be \$4.00 or less.) To a great extent the base case reflects the economic and regulatory conditions faced by a tertiary oil producer during the past several years.¹
- Lower Bound. This case reflects the minimum anticipated response of releasing tertiary oil to upper tier prices -- \$11.28 per barrel, as adjusted for gravity differential, and maintained in real terms. The lower bound case assumes a moderate level of federal initiative and research funding. From the industry perspective, this case assumes that tertiary oil recovery remains a high risk technology.²

¹The base case assumes that tertiary acreage already developed and producing will continue producing; that expansion will continue in the reservoir if the lower tier price provides at least an 8% (real) return on capital; and, that new projects will be introduced if the lower tier price provides at least a 20% return on capital.

²The lower bound case assumes that tertiary acreage already developed and being produced will continue producing; that expansion will continue for the reservoir if the price provides at least a 20% (real) return on capital; and, that new projects will be introduced, over 10 years, if the price provides at least a 20% (real) return on capital.

- Upper Bound. This case reflects the maximum anticipated response of releasing tertiary oil to upper tier prices (maintained in real terms). This case assumes a concerted and creative level of federal initiative coupled with a major research/development effort; it assumes that in the next fifteen years (by 1990) tertiary technology becomes a proven conventional means of oil recovery.¹

These criteria are translated into financial and timing assumptions for projecting proved reserves and tertiary production. The timing of proved reserves under each of the three cases is displayed in Exhibit 9.

Under the upper bound case, the analysis shows that by 1985, 17.5 billion barrels of proved reserves (in these three states) would be added to the nation's oil supply with the total 30.5 billion barrels being proved by the year 2000, as shown below.

CUMULATIVE PROVED TERTIARY RESERVES OVER TIME
(billions of barrels)

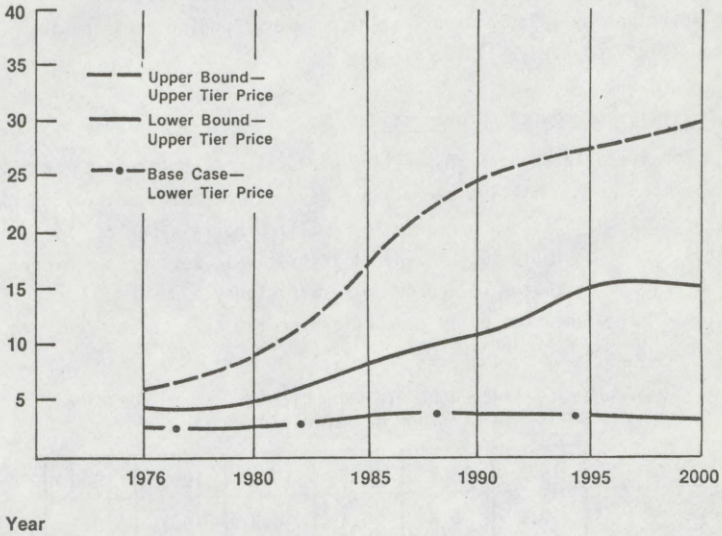
	1976	1980	1985	1990	1995	2000
Base Case	2.2	2.2	3.8	3.8	3.8	3.8
Lower Bound	4.1	4.4	8.3	11.0	15.6	15.6
Upper Bound	6.2	9.0	17.5	25.2	27.8	30.5

¹ The upper bound case assumes the same conditions as the lower bound except that expansion and new projects (introduced over 15 years) will take place if the price provides at least an 8% (real) return on capital. Considerable encouragement by FEA, ERDA, and the Administration, coupled with an aggressive stance by industry, would be required to achieve this upper bound case.

EXHIBIT 9

Timing of Proved Tertiary Reserves by Case (Total for 3 States)

Billions of Barrels



Of this 17.5 billion, two billion barrels (the 1976 Base Case) are most likely already included in existing API reported reserves.

As shown on Exhibit 10, for the upper bound case, steam drive provides the initial tertiary reserves, with CO₂ miscible flooding becoming important by 1985, and surfactant/polymer flooding contributing significantly to reserves by 1990.

4. Tertiary Production Forecasts

Considerable amounts of tertiary production (from these three states), as much as two million barrels per day, can be realized by 1985. Tertiary production could reach nearly four million barrels per day by 1995. Thus, under a timely set of federal initiatives, tertiary recovery could be a major contributor to energy self-sufficiency. Exhibit 11 and the table below show the daily production for the three cases analyzed.

ANNUAL TERTIARY CRUDE OIL PRODUCTION
(net production in millions of barrels/day)

	1976	1980	1985	1990	1995	2000
Base Case	0.2	0.4	0.4	0.3	0.3	0.2
Lower Bound	0.2	0.5	1.1	1.2	1.0	2.1
Upper Bound	0.2	0.7	2.0	3.0	3.8	3.6

Most significantly:

- Steam drive provides the bulk of the tertiary production in the early years, reaching 1.0 million barrels per day by 1985.
- CO₂ miscible flooding reaches 1.0 million barrels per day by 1990.

EXHIBIT 10

Distribution of Cumulative Additions to Proved Reserves by Tertiary Recovery Technique**(Upper Bound Case—Total for 3 States)**

Billions of Barrels

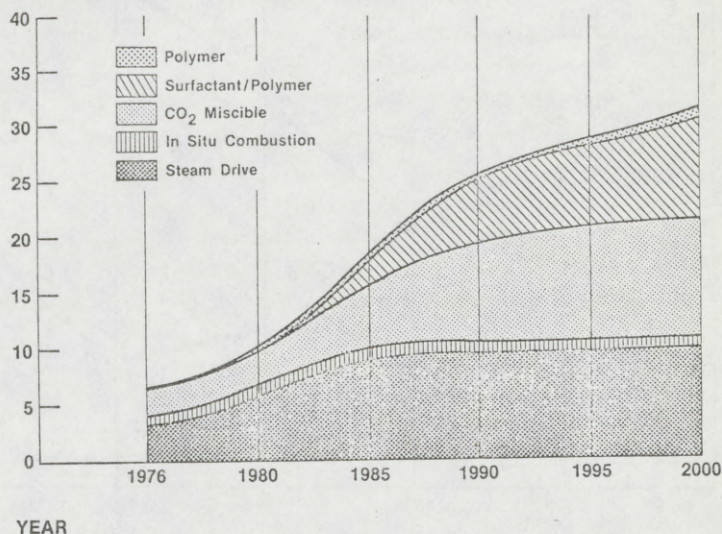
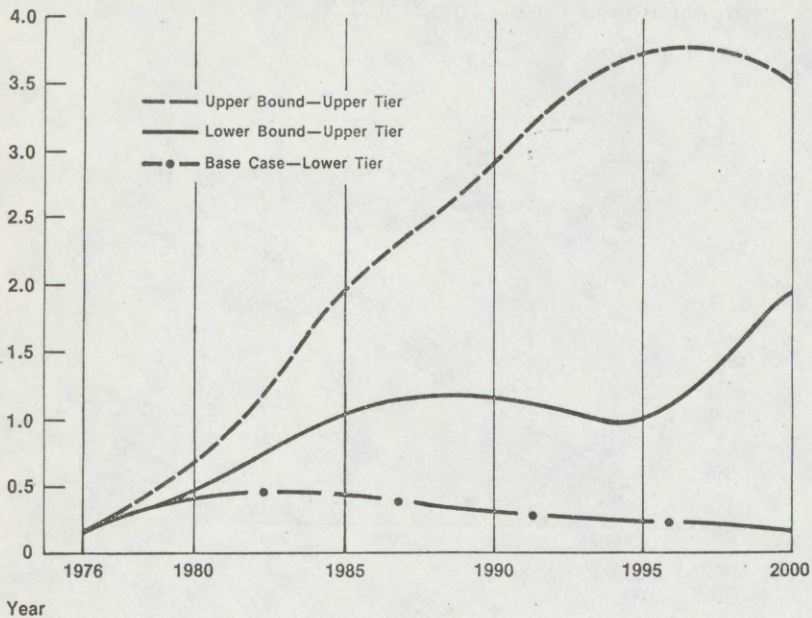


EXHIBIT 11

Tertiary Production for Three Cases
(Total for 3 States)

Daily Production (Millions of Barrels per Day)



- Surfactant/polymer flooding climbs slowly through the late 1980's at which time it accelerates sharply, reaching 1.4 million barrels per day in 1996.

The contribution of the five EOR techniques over time is shown below.

ANNUAL TERTIARY CRUDE OIL PRODUCTION -- UPPER BOUND CASE
(net production in millions of barrels/day)

	1976	1980	1985	1990	1995	2000
1. Steam Drive	0.1	0.3	1.0	1.3	0.8	0.7
2. In Situ Combustion	*	0.1	0.2	0.1	0.1	0.1
3. CO ₂ Miscible and Hydrocarbon Miscible ¹	0.1	0.3	0.7	1.0	1.5	1.5
4. Surfactant/Polymer	*	*	0.1	0.6	1.4	1.3
5. Polymer Augmented Waterflooding	*	*	*	*	*	*
TOTAL	0.2	0.7	2.0	3.0	3.8	3.6

*Less than 0.1

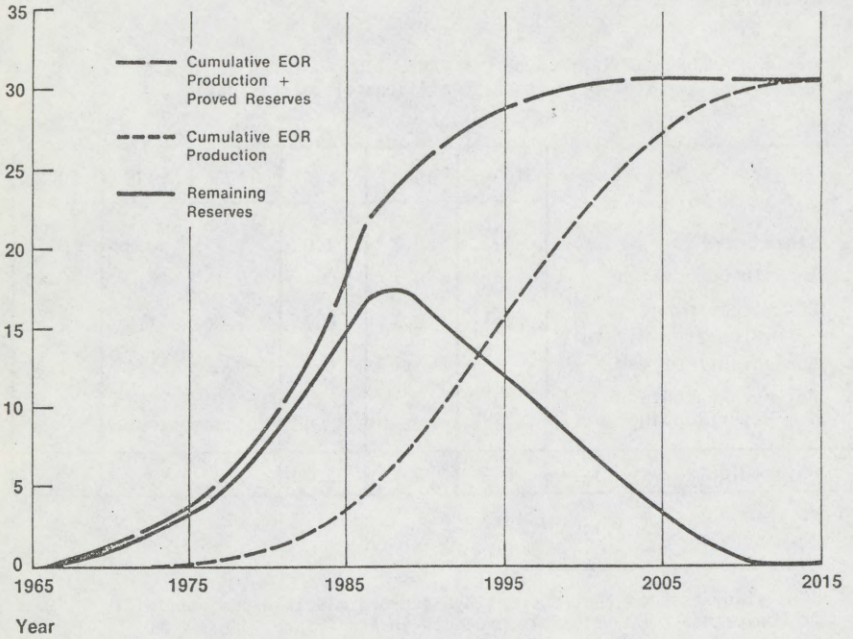
¹The study assumes that current hydrocarbon miscible projects will be converted to CO₂ miscible projects in the future.

These last two points, the timing of tertiary reserves and production, are displayed on Exhibit 12, showing the interaction of tertiary reserves and production over time.

EXHIBIT 12

EOR Production and Proved Reserves (Upper Bound Case—Total for 3 States)

Billions of Barrels



NOTE: Projections to National Totals. Given the unique nature of the states examined -- Texas with its large carbonate reservoirs, California with its viscous crudes, thick pays, and high oil saturations, and Louisiana with its highly fractured, saline reservoirs, we do not believe that projections of the findings for the three states to national totals would be valid.

CONSTRAINTS

Before the potential of EOR can be realized, certain key constraints must be overcome, namely:

- Capital. Approximately 150 billion dollars of expenditures (exclusive of well operating and overhead costs) would be required over the next 30 years to prove and produce the 30.5 billion barrels of tertiary oil projected for the upper bound case. Thirty billion dollars would be required for field development and equipment and an additional 120 billion for the injection chemicals and fluids (i.e., sulfonates, polymers, CO₂, steam, etc.). Thus, tertiary recovery, assuming an average of 5 billion dollars per year of expenditures, would become a major competitor for the yearly 30 billion dollars of oil and gas expenditures. A judicious sequencing of tertiary projects should provide sufficient cash flow in the later years. However, developments in the initial years (from 1976-1985) could be constrained by competing capital demands.

- Recovery Materials. Tertiary oil recovery will need to spawn and nurture many new ventures in chemicals and CO_2 supply. Approximately 75 billion pounds of sulfonates, 7 billion pounds of polymers, and 10 billion pounds of alcohols would be required over the next 30 years to produce the 9 billion barrels of tertiary oil attributable to surfactant/polymer recovery. However, sulfonate supply should not pose a near-term constraint. The domestic chemical industry already has the capacity to produce 500 million pounds of sulfonate per year with additional major plants coming on stream. Moreover, new plant construction has a relatively short construction lead time (3 years) and the major demand for sulfonates will not come until after mid-1985. Polymer requirements could pose some constraints given that the current production of polyacrylamides and polysaccharides is estimated to be only about 300 million pounds per year.¹

Approximately 45 trillion cubic feet (tcf) of CO_2 will be required over the next 30 years to produce the 10 billion barrels of oil attributable to this technique. While recycled CO_2 can substitute for about 20 percent of the requirement, natural sources will still need to supply 25 tcf and manufactured sources the remaining 10 tcf.

Currently, CO_2 supply appears to provide a major constraint. While considerable quantities of naturally occurring CO_2 are produced with natural gas and CO_2 is a by-product of many chemical and refining processes, its limited value has led to CO_2 being considered a waste material. Recent changes in the economic value of CO_2 have led to a renewed interest for discovering and capturing CO_2 supplies.² However, major improve-

¹Chemicals for Microemulsion Flooding in EOR, March 1976 by Gulf Universities Research Consortium.

²L.W. Holm, "Status of CO_2 and Hydrocarbon Miscible Oil Recovery Methods", in Journal of Petroleum Technology, January 1976.

ments in transportation and recycling will need to be made before the full potential of this recovery technique can be realized.

The other potential constraints of field equipment and drilling rigs seems well within the industry's capacity to be solved and are addressed in the full report.

- Technical Risk. Though the basic concepts of enhanced oil recovery have been discussed and tested for some time, (see Appendix I for a historic perspective), EOR is still a new, emerging technology. As such, considerable uncertainty and controversy surround even such basic questions as: How efficiently will the process mobilize oil? How can one confidently measure the incremental oil added by the tertiary technique? What will be the long term cost for the injection fluids or materials? What specific reservoir properties are detrimental to particular techniques? These basic questions of effectiveness, measurement and costs will need to be carefully assessed, technique by technique, if today's perceptions of risk and uncertainty are to be overcome.

In terms of economics and timing, the effects of these uncertainties are reflected in the high risk premiums attached to tertiary projects and the relatively slow rate of expansion EOR has experienced from the laboratory to field pilot to full field development.

We believe, however, that many of the current technical risks can and will be reduced. Such risk reduction can result from:

- an active basic and applied research program
- the sharing of knowledge from industry field projects
- sufficient research-based inquiry into what worked or did not work, and why
- demonstrations of proven techniques
- appropriate economic incentives and buffers against large-scale failures.

The efforts of FEA, ERDA and the industry will need to be combined over the next decade, to bring these risks into better understood and, hopefully, narrower bounds.

- Price uncertainty. The results of our analyses argue that EOR development is highly sensitive to the price of oil. Given that the greater proportion of tertiary production has been classified as "old" oil and priced at \$5.25 or less, one should not be surprised at the slow rate of EOR adoption. The recently passed energy price legislation with its proposed adjustments for inflation and property by property decline curves provides considerably improved economics. Many price impediments, however, will still exist, diluting the potential value and impact of these pricing provisions. Based on these regulatory uncertainties, we found few producers willing to assume a long term "upper tier" or world price. Consequently, many promising EOR prospects are being deferred.

Specifically, the producers' apprehensions stem from their concern that: the allowed increase in prices may be inadequate to cover rapidly rising costs; the OPEC cartel might break leading to a drop in world prices; and, future domestic oil prices may be inadequate in face of uncertain legislative or regulatory actions. An established, stable, long term price for tertiary oil could be the single most important stimulus for launching enhanced/tertiary oil recovery.

WHICH CASE DOES THE FUTURE HOLD

The findings from this study indicate that enhanced/tertiary oil recovery can play an important role in seeking energy self-sufficiency. However, the oil industry and its tertiary oil recovery efforts are currently at a crossroads. The industry can proceed at a modest, measured pace, seeing prospects dwindle as the domestic oil fields decline and are shut down; it can respond to the improved economic and regulatory conditions but, given limited federal involvement, the risky, capital intensive nature of the task and the indirect, delayed return from research, proceed at a moderate pace; or, it can launch a major, concerted effort, joined by creative federal leadership and research, focused on targets of high potential and on proving this new technology.

Which choice the industry will make depends heavily on near-term decisions of the Federal government. As the three cases demonstrate, alternative incentives, regulatory and R&D strategies can lead to vastly differing results. Reaching the upper bound case demands that sizable resources be committed and that the current technological constraints be overcome. The potential capacity of the industry and the Federal government appears to be sufficient to the task; however, it will need to be harnessed and carefully guided.

The purpose of this report was not to recommend any specific regulatory, legislative, or R&D alternatives. Rather, the report sought to illuminate the consequences of broad classes of policy. The three cases analyzed, we believe, delineate the range of potential outcomes. The development of a full set of detailed strategies will require further planning and analysis.

We hope that this analysis of the potential and economics of EOR will assist the federal government in formulating a judicious policy toward improving oil recovery from the nation's crude oil reservoirs.

Senator HASKELL. Senator Hart.

**STATEMENT OF HON. GARY HART, A U.S. SENATOR FROM THE
STATE OF COLORADO**

Senator HART. I appreciate the opportunity to testify here on enchanted oil recovery.

As the Senator from Texas indicated, enhanced oil recovery is what might be called the sleeping giant among alternatives to imported oil. This process can produce as much oil from old reservoirs as has been pumped over the last half century. And as both industry and Government studies point out, enhanced oil recovery can supply potentially large amounts of oil in the late 1980's when this country's oil situation promises to be critical.

In fact, in 10 years, if commercialization of enhanced oil is accelerated, enhanced oil recovery could provide an amount of oil equivalent to two Alaska pipelines. Two million barrels a day of enhanced oil would reduce the country's balance of payment up to \$20 billion a year.

Unlike some other fossil fuel alternatives which pose significant environmental problems, recent studies indicate that enhanced oil recovery can provide this energy with very little threat to environmental values.

Now with all of these advantages, EOR would seem ready for intense development work within the oil and gas industry. But EOR, like all new energy technologies, faces serious obstacles.

The most promising EOR methods have only recently reached the field-testing stage. Researchers are uncertain as to how well the technologies will work in the field, how much oil will actually be recovered, and what process refinements will need to be made. Adding to these technological questions are serious uncertainties about the eventual cost of EOR-produced oil.

In the face of these unknowns, EOR may not become productive until a decade or two too late. To encourage rapid investment in EOR, I have introduced legislation that will, in my judgment, help reduce the most serious EOR uncertainties.

The legislation I have proposed will speed EOR commercialization by reducing the uncertainty over future prices, by helping small firms gain financial backing, and by assuring that tax rules do not suddenly change the effective cost of EOR operations. The pricing and financial provisions that I have described are contained in the Enhanced Oil Recovery Commercialization Act of 1978, which is S. 2999.

Although EOR oil is expected to cost less than OPEC oil by the mid-1980's, there is a need for price guarantees on selected, "first of a kind" operations. Due to the risk associated with new techniques on new geological structures, and due to the high costs of chemical injection, a price of up to \$25 a barrel will be needed to attract private investment.

Without Government price guarantees, firms will most likely wait until the mid to late 1980's, when the market price of oil is projected by many to reach \$25, before they initiate these EOR operations. It then will be another 5 to 10 years before large numbers of full-field operations are undertaken.

This decade of leadtime can be eliminated if the Department of Energy guarantees up to \$25 a barrel now for a few selected high-cost operations. With successful demonstration of these techniques in the early 1980's, the industry will be ready to initiate dozens of these ventures in the mid to late 1980's, when the market price is due to reach about \$25 per barrel.

I think, Mr. Chairman, that's the key element that I want to stress here.

This bill is designed to eliminate this leadtime gap. What I think we have learned in this country is that if the price is right, we can come up with the technology and the process to do about anything within reason. The question is: How long can the country wait in the interim between when we've run out of the conventional supplies and when the new supplies are available? And what I think the role of the Congress and the Government should be in this area—what the Senator from Texas has described as the "exotic products"—is to help reduce if not eliminate that leadtime so that this country doesn't suffer the gap in between.

Under my legislation, the Department of Energy will guarantee the price that I've suggested only for EOR operations which are not economically feasible at current world prices and which will demonstrate a technology having wide applicability thereafter.

To test the two major high-cost techniques in the most promising geological zones will require 10 to 12 full-field demonstrations, at a maximum anticipated cost of \$200 million.

The full-field operations eligible for price supports will get underway in the early 1980's if this legislation is passed at a time when world prices are expected to be \$5 or so less than the \$25 support price. By the mid-1980's, the market price, as I have indicated, is expected to be about \$25, and at that point the Treasury would, of course, not incur further costs.

For so-called second generation EOR operations, those already in being, where the technology has already been proven, the oil should be allowed to be sold at world oil prices. Deregulation of EOR oil is needed because the cost of chemicals alone, which is estimated to be between \$5 and \$13 per barrel, exceeds the price of most controlled oil.

In some circumstances, enhanced oil recovery will be initiated before primary and secondary recovery is exhausted, as the Senator from Texas has indicated. Under these circumstances, my proposal would deregulate the oil which is recovered in addition to primary and secondary recovery. And, of course, this is the major difference between this legislation and Senator Bentsen's. To determine how much oil from a well is deregulated, and how much is still controlled, a company would determine the production increment resulting from the EOR operation. Although there is considerable uncertainty over the production increment due to EOR, estimates of primary and secondary production, of course, are quite precise at the present time.

As an example of one such estimate, I have attached a graph to this statement, which is drawn for an EOR project by the Kewanee Oil Co. This graph shows clearly how much additional productions results from an EOR project injecting chemicals to improve oil flow.

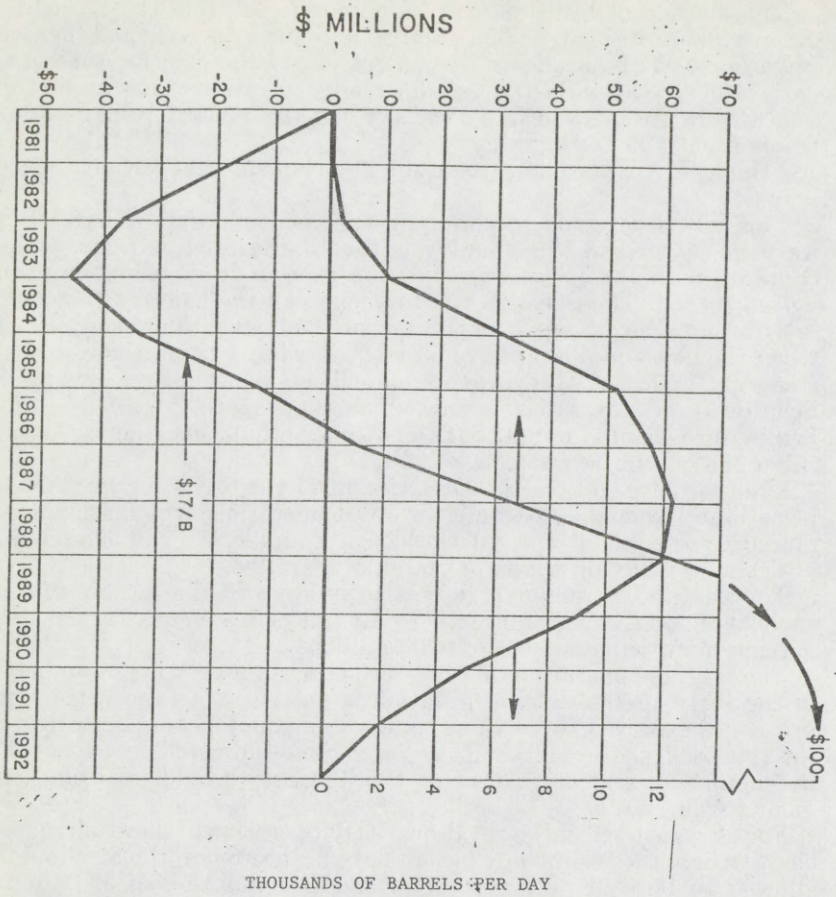
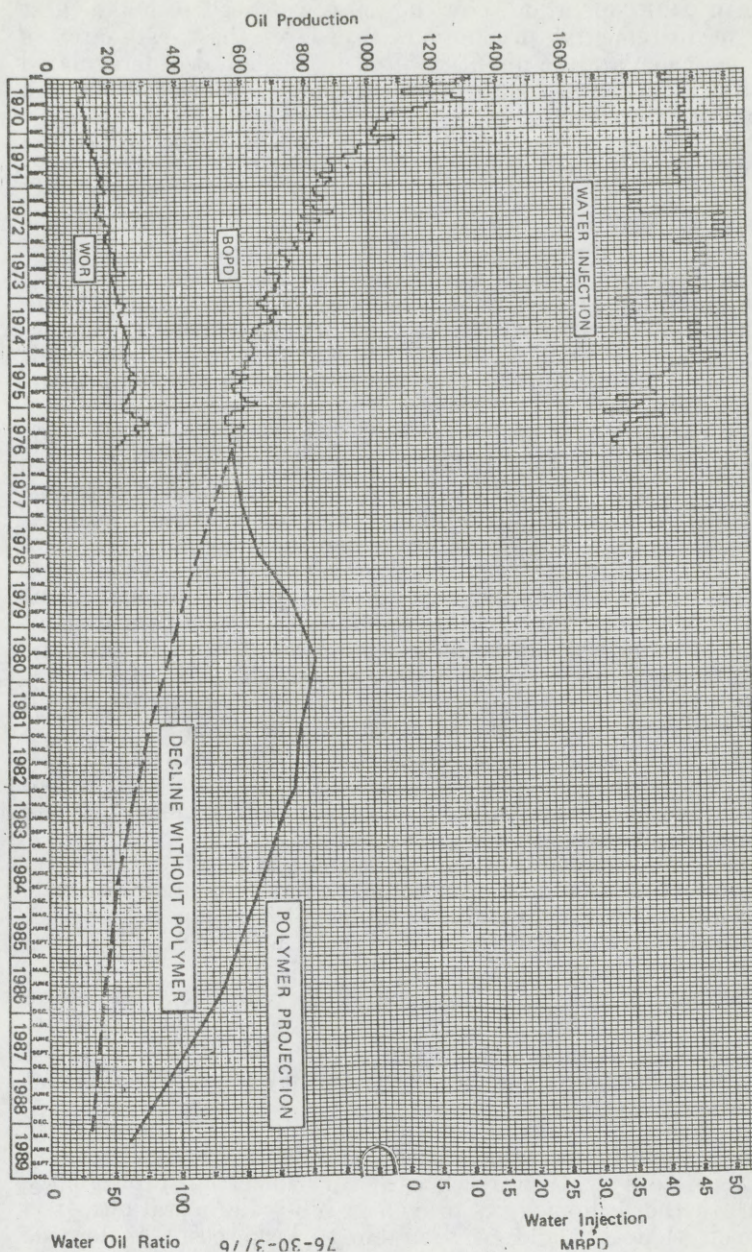


FIGURE 1.—EOR oil production and cumulative net cash flow for representative micellar-polymer flood. 3 years into the flood the cumulative net cash flow is minus \$45 million.

GRAPH 1.



NORTH STANLEY PROJECT
INJECTION-PRODUCTION HISTORY

Source: Society of Petroleum Engineers of AIME, "Improved Oil-Recovery Field Reports," vol. 2, No. 3, North Stanley Stringer Field Kewanee Oil Co.-ERDA.

To judge the economic feasibility of investing tens of millions of dollars in an EOR operation, any company will need to make these estimates of incremental production. Based on these estimates, a company can calculate the quantity of oil to be sold at a deregulated price by subtracting the estimate of primary and secondary production from actual daily production.

To ensure that decontrolled EOR oil does not depress the price of old oil, my legislation will take EOR oil out of the composite price which sets the legal maximum average price for oil sold in the United States. In that way, EOR production should have no effect on the rate of production from old wells not under EOR programs.

Mr. Chairman, high prices themselves will not be sufficient to ensure that small and intermediate-sized oil companies can enter and compete in a new enhanced oil recovery industry. Enhanced oil recovery operations require tens of millions of dollars for injection of chemicals before oil is actually brought to the surface. I have attached a graphic illustration of that fact.

Small companies would need to borrow anywhere from \$20 to \$50 million in order to undertake EOR. And yet traditionally banks are reluctant to loan that much without clear evidence that their investment is sound. Until EOR operations establish a successful history, few lending institutions will be willing to loan for these purposes without guaranteed repayment.

In this legislation, therefore, I propose that DOE guarantee loans for so-called "first of a kind" EOR operations when a firm demonstrates that it cannot otherwise obtain financing. To qualify for the loan guarantee, a company could produce no more than 25,000 barrels per day by any method. Under current conditions, the 33 largest oil companies would not qualify therefore for this provision.

Although I have opposed other instances of Federal loan guarantees, I believe they are necessary in this specific case. Small businesses simply would be excluded from the new EOR industry unless they are given assistance for early capital costs.

Under this legislation, DOE would guarantee loans up to a maximum potential liability of \$200 million for small or independent companies. The legislation authorizes a full \$200 million to cover potential losses. However, since it is doubtful that many loans will default, this sum will probably never leave the Treasury.

Mr. Chairman, at this time the Internal Revenue Services allows firms to treat the costs of injecting materials as a current expense. Now because these materials may have a useful life of several years, the IRS could conceivably rule in the future that these costs must be amortized over a several-year period.

If IRS makes this change in accounting procedures, the effective costs of EOR could be increased by several dollars per barrel, adding significant cost to a venture which is of very uncertain profitability already. Until the technology is proven in full-scale operations, it is my judgment that it would be desirable to keep costs as low as possible.

And, therefore, I proposed a companion piece of legislation, called the Enhanced Oil Recovery Tax Act of 1978, prohibiting the IRS from changing current expense-accounting for EOR operations for up to 8 years. And thereafter EOR operations could be treated for tax purposes the same way any other business venture is treated.

As I have indicated, the environmental impacts of enhanced oil recovery are expected to be small, although environmental considerations may limit some methods of EOR in some locations.

There are several main environmental considerations. First, air pollution can result from the use of gasoline and diesel engines in the steam-injection method. In parts of California where air pollution is already a problem, the steam injection method may therefore be restricted.

Second, the micellar-polymer process, which injects detergent-type chemicals to break up oil into smaller droplets, now requires fresh water. Until this method is refined to use naturally occurring saline water, this process may be limited in the water-short States of the Rocky Mountain West.

Third, there is a very slight chance that detergent chemicals could leak into below-ground fresh-water systems. Injection techniques must be monitored closely to insure that this does not occur.

Mr. Chairman, in light of these potential problems, EOR may need to proceed slowly in some parts of the country. On balance, however, the environmental constraints are not expected to severely limit EOR development.

In summary, Mr. Chairman, we need to speed enhanced oil recovery by reducing the uncertainty over price. The legislation I have described is designed to achieve this goal by, first, guaranteeing projected market prices for first-of-a-kind operations; second, providing a deregulated price for second generation operations; and, third, making loan guarantees available in special circumstances to insure that independent producers are an important competitive element of the new EOR industry.

With this more rapid formation of a full-scale EOR industry, it is my judgment that our country will be able to reduce oil imports by 1 to 2 million barrels per day by the late 1980's and the early 1990's. And given our need for freeing ourselves from this form of energy dependence, I think the EOR industry should be given this stimulus.

Thank you very much.

Senator HASKELL. Thank you very much, Senator Hart. Who under your legislation would determine what was incremental production due to tertiary recovery?

Senator HART. The calculations would be done by the companies themselves and submitted for approval by the appropriate state regulatory authorities. If no such review is performed by the State regulatory then the Secretary of Energy would make the determination. Although I do not think it is clear in my bill, I intend that the DOE establish criteria for the State regulatory authorities to use in establishing their review and approval regulations.

Senator HASKELL. And would the Department of Energy be responsible under your legislation for monitoring enforcement to prevent fraud?

Senator HART. Yes, that is my intention. If the provisions of the draft legislation which I introduced are not strong enough, certainly they could be strengthened in the committee or on the floor to that effect.

Senator HASKELL. I understand that under your legislation the Department of Energy would make the determination of (a) what technology qualifies as tertiary recovery, and (b), what oil is produced as a result of tertiary recovery. Is that correct?

Senator HART. That is not quite correct. The State agencies would approve the company's proposal. I don't think we would need a huge bureaucracy in the Department of Energy to do that. I think if the burden is placed on the companies to come forward with the facts, and the date, they would be reviewed. If there seems to be substantial question about it, it could be investigated by the Department.

Senator HASKELL. We need enough people at least to see that they were reporting accurately.

Senator HART. Absolutely.

Senator HASKELL. Had you considered any alternate possibility on tertiary recovery? You talk in terms of a \$25 price for a limited period of time, I realize. Have you considered the possibility of permitting amortization of investment plus a profit on investment to be added to the price of new oil as an alternative?

In other words, how do we know that \$25 is right or wrong?

Senator HART. The figure on oil prices that I have indicated in my testimony is based on the projections done by the Department of Energy as well as a number of outside entities about what world oil prices are expected to reach by the mid 1980's, which is the time frame that we are aiming toward.

While I am not familiar with the financing incentive system that the chairman has suggested, it would be an alternative to this one. I think it was taken in consideration in our drafting of this legislation. We felt that this would be a way than what that alternative might suggest.

Senator HASKELL. I don't believe I have any further questions. Senator Hansen.

Senator HANSEN. May I yield to Senator Bartlett first again, if that would be all right with you, Mr. Chairman?

Senator HASKELL. Certainly.

Senator BARTLETT. I want to say to my friend from Colorado I appreciate very much your appearing before the committee and presenting your bill.

As I read it, am I correct that it is geared more toward enhanced oil recovery technology development and demonstration and not toward general economic incentives for enhanced recovery?

Senator HART. That is partially correct. My bill does have incentives for proving very new technologies. And I think that's the principal difference here between this legislation and that proposed by the Senator from Texas. My bill also has incentives for rapidly commercializing technologies once they are proved.

Senator BARTLETT. In what way would it duplicate ongoing DOE cost sharing purpose in enhanced oil recovery? There is a project in Osage County, Okla., where private capital and public money of DOE are working together in a tertiary effort.

Senator HART. Well we don't want to overlap, certainly. And the purpose here is, as I've indicated, to get upward of a dozen full-field commercial operations going in the five or six regions around the country, major oil recovery regions, using the two principal technologies or variations thereof in each of those regions. And that's how we come up with 10 to 12 full-field test operations, and those are the ones that we want to encourage with one part of my bill.

I think my bill would supplement what the Department is already doing and not overlap.

Senator BARTLETT. I think I am correct that your loan program of \$200 million would apply for new and improved methods. The \$25-per-barrel guarantee would be a first of its kind. I don't know whether "new and improved" is different from "the first of its kind." But then I want to try to have you explain this. I would ask you to explain it, and I know you will.

Then also you provide for the incremental increase to be the free market from qualifying tertiary enhanced to oil recovery projects. I presume in this case that would not be a first of its kind or would not be a new and improved, but would be a recovery approach, recovery method, that had been used before.

Senator HART. Well, let me start at the first part of that question. The goal of the legislation, including the deregulation of EOR oil, support price, as well as the loan guarantees, is to encourage as many elements of the industry as possible, including the small and independent operators, to improve on the technologies that we already have. Obviously, if companies are already undertaking some processes now—and the results are pretty broadly available—there doesn't seem to be a need for Government incentives like loan guarantees or price supports.

What we are trying to do is induce expansion of new technologies and an expansion of the base in terms of the number of companies undertaking it.

Obviously, it would be extremely difficult, if not impossible, for the Congress or any of its committees to draft legislation so precise as to, in fact, administer the program. You are going to have to leave some discretion with the Department, the Secretary and his designee. And, therefore, we have used language like "first of a kind" understanding these terms will need further refinement in practice. And I think we would want to make the legislative history pretty clear that there is going to be some secretarial discretion as to what kind of technologies and what kind of operations qualify.

But the intent of the provisions for loan guarantees and price supports is to broaden the base in terms of the number of companies, and to increase experimentation in terms of technology.

Senator BARTLETT. Am I correct, Senator Hart, that the Secretary would define the terms of "new and improved" methods of advanced oil recovery, on the one hand, for qualifying for the loan program, and for the \$25 a barrel which would be a "first of its kind" operation, would define terms there? And then for the incremental increase, he would again define where that change could be made. I mean, what methods used would qualify for incremental increase.

Senator HART. That is correct.

But on the last part of the question, on the incremental production, again I think that's going to be a fairly factual, scientific kind of a calculation, where there will be more, I think, administrative discretion required in terms of defining what technologies qualify.

I would hope that we could pin down how much oil is coming from the enhanced process, using, as I've indicated, the fairly hard statistics firms have now on primary and secondary. The incremental production is determined by subtracting the estimated primary and secondary production to get fairly precise figures. Certainly by the time these operations are underway in the 1980's, we will have more experience to determine how much of this oil is coming from the enhanced technology.

Senator BARTLETT. Would your intent on incremental increases be for projects beyond secondary recovery of water flooding and would it be for tertiary projects only?

Senator HART. That's correct.

Senator BARTLETT. Your loan guarantee provision would apply only to small independent oil producers and only for instances in which independent oil producers own at least 60 percent of the working interest. Is that a correct statement?

Senator HART. That is correct.

Senator BARTLETT. Is it not true that in most of the big fields with large enhanced oil recovery potential that the majority of the working interest is owned by major oil companies?

Senator HART. I think that is correct in many cases.

Senator BARTLETT. I mean, as a general statement.

Senator HART. Yes.

Senator BARTLETT. Probably not entirely.

Is it correct that most of the research and development developing improved methods or new methods or first-of-a-kind methods come from the research of the major oil companies?

Senator HART. Well the use of the term "most" is, of course, relative. Most of the research is by the majors, but the independents are trying to get involved, too.

Senator BARTLETT. "Most" is only half plus one, I guess.

Senator HART. Yes.

I don't know how to quantify that. The operations that I am familiar with, most familiar with, are coming from independents in my State. We can provide the statistics on that I think.

Senator BARTLETT. All right. I would appreciate that for the record.
[The information follows:]

The Department of Energy reports that in 1977, there were 132 enhanced oil recovery projects underway in the United States. About 43 of these were commercial steam drive projects. Most of the remainder were pilot projects to test the newly emerging technologies using carbon dioxide polymers, or surfactants. Of the 132 EOR projects, 35 were undertaken by independents. This shows that independents are an active group in EOR.

The Department of Energy has cost-sharing programs with 21 companies to test EOR technologies in pilot operations. Independents are doing 6 of the 21 projects.

Senator BARTLETT. I know that independents do involve themselves in new methods, modifications of methods, new changes in tertiary recovery, or do involve themselves in secondary recovery by water flooding, and combinations of water flooding and tertiary recovery.

But I think oftentimes, and most often, the technology does come from either the service companies who develop the chemicals or develop the techniques, or the major oil companies, and probably particularly the majors.

Senator HART. Well I might want to quarrel with that. That is kind of an objective judgment. I think an awful lot of improved technology over the years in energy and petroleum, related energy, has come from independent and smaller operators. But we are really talking now about relative judgment.

Senator BARTLETT. Well I think that would be nice. And I don't think all my judgment is subjective. I think some of it is objective. It may be a little old. But I know that when I was involved in water

flooding—and there were a lot of independents involved, and I was involved with an independent—the majors were also very much involved with the technological development.

Senator HART. I think the question is who starts it and then who picks it up. I hope we can encourage more independents to help start it up.

Senator BARTLETT. Would it be important for independents to participate in commercial demonstration programs operated by majors, as in those operated by independents, where they own a share of a field that might be unitized but do not own 60 percent?

Senator HART. Oh, I suppose it would be important.

Senator BARTLETT. But your bill would not permit this?

Senator HART. No. It wouldn't prevent it. It wouldn't reward it.

Senator BARTLETT. But it wouldn't support it?

Senator HART. No.

Senator BARTLETT. There are two types of risks involved in enhanced oil recovery: process risk (how well will the process work?) and reservoir risk (how amenable is that particular reservoir?).

Is it not probable that the first generation projects will carry the greatest process risk and perhaps the least reservoir risk—

Senator HART. I don't know.

Senator BARTLETT [continuing]. As tertiary recovery will be tried first on the best reservoirs, I would presume, and that the second-generation projects would involve less process risk but greater reservoir risk?

Senator HART. Well I suppose that's true under normal market conditions. But what we are trying to do is shortcut some of those risks by getting, as I have indicated, more people involved in more parts of the country.

Senator BARTLETT. The point I am making is, don't all enhanced recovery programs need the same incentives? I think this is the point that the Senator from Texas was making, that you can have a demonstration project that will work, but when you try it out on a field basis it doesn't work. Or what often happens is that you have a project that will work on a certain field but it won't work on another field. The reservoir conditions vary. Characteristics vary from field to field; the water content and so on.

These I think do affect the prospects of recovery and do affect the recovery itself.

So do you feel that there is need of some incentive, such as price, for all tertiary recovery methods? And in addition for secondary, including waterflooding, which is the one that is most broadly used.

Senator HART. Well I want to stay within the four corners of this bill. It doesn't affect secondary processes. This is an enhanced oil recovery bill, meaning tertiary recovery. And we can take up the subject of would it provide incentives on secondary recovery in another context.

I am always suspicious of a piece of legislation that attempts to do everything. This bill does not attempt to do everything. It attempts to do a few things. And it doesn't solve all the problems of enhanced oil recovery, even if you include secondary recovery in the definition, nor is it going to reward everybody who does anything in the enhanced oil recovery field. What it is trying to do is to get an independent operator as well as major oil companies into the business to help

reduce the risk. Not eliminate the risk but reduce it sufficiently that it will attract more people into it and cut down the technological leadtime, that I have indicated. Now that is all this bill tries to do.

And I guess the answer to your question is no, I don't believe we should attempt to award everybody who tries to do anything having to do with enhanced oil recovery.

Senator BARTLETT. Well I guess my suggestion is rather than reward everybody, why not stop restricting everybody with price controls.

Senator HART. Well I think the price control issue pertains to the second part of this bill. E and R oil is deregulated for second generation (meaning not first of a kind) operations.

Senator BARTLETT. Yes. But if the price controls were removed from tertiary oil, then oil that's priced at \$5.25 would go up to \$13.50 or something like that. And wouldn't that in your mind stimulate much development of tertiary projects and programs, including new and improved methods and first of a kind methods?

Senator HART. Well the answer is yes, once again. But as I stated in my opening remarks, my bill attempts to do that. It does decontrol enhanced tertiary recovered oil.

Senator BARTLETT. Just incremental production.

Senator HART. Pardon me?

Senator BARTLETT. On an incremental basis.

Senator HART. That's correct.

Senator BARTLETT. But our problem is not, as far as domestic production is concerned, as the Senator knows, is not a narrow, small problem, it's a rather large problem. And tertiary oil recovery itself is rather narrow compared to the total energy picture. It seems to me that we would want to go into this a little more with the administration witnesses, but it seems that the roughly \$2 billion that DOE has been holding in its hip pocket should be utilized, plus other revenues coming from the private sector which would come with decontrol to expand our domestic production. So if this were done in a tertiary area, it would not be a very major expansion of incentives, but would be rather a minor one, certainly compared to \$20 billion plus.

And so I feel that the effort that the Senator is making, which is certainly to develop new reserves, can be accomplished along with a broadening effort in the whole tertiary field, which is greatly needed today if we are going to really get anywhere.

Senator HART. Well I am not sure that we are saying different things. I think the Senator is making an argument about decontrolling old oil. And if that's what we want to discuss in this hearing, I will be glad to give him my views on it.

What I am here to do is to try to get people into the enhanced oil recovery, tertiary recovery. And I don't think that's a small thing. I think all of us agree that there is an enormous amount of oil out there to be recovered. Although there's more than one way to do it, I have offered one way which I think is fair to producers and consumers as well.

Senator BARTLETT. Well I was talking about tertiary primarily and the importance of expanding it in every direction that we possibly can, which I think would be much greater with deregulation of tertiary oil. Not just the incremental increase.

Senator HART. My bill provides that.

Senator BARTLETT. Well it provides for the incremental increase.

Senator HART. That's right. But it is the incremental oil that's tertiary.

Senator BARTLETT. Production from the whole project, I think, should be considered tertiary.

Senator HART. Well you don't make all the oil in the ground. If you are already covering some primarily and secondarily, you don't make it all tertiary just by sticking some chemicals down there.

Senator BARTLETT. Well I think it is a matter of amortizing the investment in the project. I think your efforts would restrict the total effort more than is justified. We have been restricting it all the way along the line. I think we should completely remove the barriers that we have been putting up.

I thank the distinguished Senator very much.

Senator HART. I simply must say I don't quite understand, by offering a piece of legislation like this, to provide a variety of incentives to people that go get oil they wouldn't get and the process that presently is being used to restricting.

Senator BARTLETT. I guess I am saying that I think this is a step in the right direction, but it does not go far enough. It's not taking a giant step, it's taking a ministep.

I thank the distinguished Senator.

Senator HASKELL. Thank you very much, Senator Hart. Do you have something, Senator Hansen?

Senator HANSEN. I will try to make it brief, Mr. Chairman. I was impressed, Mr. Chairman, in your opening statement when you spoke about the delay between the assurances that DOE has given and they're actually implementing those changes. You called our attention to the fact that they were going to make some changes. The most recent notice of rulemaking concerning tertiary recovery was published April 17, 1977. I alluded to that earlier. And I think that is a real problem.

Senator Hart, there are a number of restrictions in S. 2999, limitations to independent oil producers, a requirement that independents own 60 percent of the working interest; limitations to commercial demonstrations, and first of a kind operations and requirements for Federal review and classification.

You spoke about the desirability of trying to qualify what oil is presently being recovered from these wells so as to get a handle on ways to measure the enhanced recovery.

My question is, given the price incentive, I should think it might be easier to let them make their own determination rather than going through the lengthy process of DOE approval.

I say that because frankly DOE has talked a better game than it has delivered. And it seems to me that if we were able to do what you suggest, and if it could be done quickly, I don't know that I would have any objection but I do have to agree with you, Mr. Chairman, that so far the track record of DOE hasn't been one that inclines me to believe that they could get this done.

Do you think that this could be a problem, too?

Senator HART. I think we all have had our experience at various agencies with paperwork and delays and tools and all the rest. And it's a balance in consideration. I think any time you are spending the taxpayers' dollars you have got a constitutional and legal obligation to

cross the T's and dot the I's. The point beyond which what becomes good administration and becomes bureaucratic delay and foot dragging is a matter for personal judgment.

My own judgment is that there's an adequate congressional record here made in the committees and on the floor. When legislation of this sort is passed, we intend it to be administered efficiently. And yet protect the American taxpayers who are really being moved into this as guarantors. Then I think I would hope the DOE would follow that congressional mandate. If we didn't, we have got oversight. We have got authorization hearings. We have got all the other mechanisms that crack the whip.

Senator HANSEN. I would just conclude by saying in the meantime, of course, I think a lot of wells are going to be shut down, or at least that's been our experience in Wyoming.

Thank you very much, Senator Hart.

Senator HART. Thank you.

Senator HASKELL. Our next witness is Mr. Langenkamp, Deputy Assistant Secretary of the Oil, Natural Gas and Shale Resources of the Department of Energy.

We have until 12:30 to meet, and we've got one, two, three, four, five more witnesses. So I would hope that our witnesses would be as brief as possible. And I would hope that the committee members would restrict their questions as much as possible.

Mr. Langenkamp, would you proceed?

Mr. LANGENKAMP. Senator Haskell, I understood Senator Bartlett wanted to make his statement after—

Senator HASKELL. Oh, that's right, He did.

Senator BARTLETT. Thank you, Secretary Langenkamp. Mr. Chairman, may I proceed?

Senator HASKELL. Go right on ahead.

Senator BARTLETT. All right. Thank you, Mr. Chairman.

STATEMENT OF HON. DEWEY F. BARTLETT, A U.S. SENATOR FROM THE STATE OF OKLAHOMA

Senator BARTLETT. I am pleased that this hearing on enhanced oil recovery has been called today. It is a step in the right direction. It has been a long time coming.

As I have pointed out so many times in this committee and on the Senate floor over the past 15 months, the President's proposed energy program contains at least one major flaw: it ignores the need to increase domestic energy production.

Underlying the exclusive emphasis on conservation at the expense of production is the false assumption that the United States has virtually exhausted its crude oil and natural gas reserves.

To put it another way, the argument goes that there is no sense allowing the "fat cat" oil companies to make windfall profits, because the additional income they would receive from partial decontrol of crude oil prices could not be put to any productive use, inasmuch as there is no more oil and gas to be found.

Mr. Chairman, people who make such statements do not understand the oil and gas business at all.

The economics of oil and gas production are not markedly different from the economics associated with the production of any other goods or services. Businessmen generally, including oil operators, make

their decisions on whether or not to invest in a given enterprise by estimating how much the operation will cost and what kind of return on their investment they are likely to realize.

In enhanced oil recovery, as in wildcatting or in marginal well operations, as the costs increase and the likelihood of earning a return on the money invested for such operations is reduced, oil companies, like any other business, reach a point where they decide that the return is insufficient to justify the investment. This, of course, assumes they have the necessary capital for the investment in the first place.

Domestic production of crude oil can be increased significantly by developing and encouraging more efficient methods of recovering oil from known reserves. Only about one-third of the 440 billion barrels of oil discovered in the United States will be produced under current economic conditions. More efficient methods to recover the known remaining 300 billion barrels are available, but their costs are high. The return, however, can be sufficient with the proper incentives.

Various studies, including one by the Office of Technology Assessment and another by the National Petroleum Council, have estimated that an additional 30 to 50 billion barrels of oil could be recovered at present market prices. At higher prices, the potential exists for even greater recovery. It is thus imperative to put this potential domestic crude oil production in parity with imported oil by exempting enhanced recovery crude oil from price controls.

As I have said before, no barrel of domestic oil should be left in the ground unproduced at a controlled price lower than the cost of the imported barrel that must replace it.

The Congress has recognized the need for price incentives for enhanced oil recovery, and in 1976 directed the President in the Energy Conservation and Production Act (ECPA) to implement a program of price incentives for tertiary enhanced recovery techniques.

In August of last year the Federal Energy Administration assured us that the regulations would be issued "in the near future." In December, we learned that the proposed regulations were on Secretary Schlesinger's desk, apparently held hostage for passage of the COET (crude oil equalization tax) program.

We have yet to see any price incentives proposed by the administration for enhanced oil recovery or for any other category of production. Instead, we have an accumulated deficit in producer revenues—the difference between what Congress authorized and what the administration has allowed—approaching \$1.9 billion and growing.

If this Nation is to stem the tide of imported oil, and arrest the mounting trade deficit and resulting erosion of the dollar, then we must increase domestic energy production. Punitive pricing policies for oil and gas can only make the situation worse.

Mr. Chairman, inasmuch as this hearing was called to deal with enhanced oil recovery, I will limit my remarks to that area, though it covers only a portion of the domestic energy supply problem.

There are six general qualifications which must be fulfilled, I feel for any enhanced oil recovery program to work effectively and efficiently for the United States.

One, the framework for granting price incentives must be simple, understandable, and predictable, not subject to capricious change or reinterpretation.

Two, price relief should be generic in nature and available to all operators on a nondiscriminatory basis. For it to be otherwise would be unfair and anticompetitive.

Three, the price incentives should be broadly applicable to all techniques used to increase crude oil production beyond the primary level. Countless numbers of secondary recovery or waterflood projects would be implemented to greatly increase our domestic crude oil production, if only the price incentive were there.

Four, the price incentive should apply to all production from a bona fide enhanced recovery project, not just to an arbitrary or calculated production increment. Price relief for only a fraction of the production from a project will not justify the enormous front-end investment required.

Five, price relief should be made available to qualifying existing enhanced recovery projects, as well as to new or expanded projects. This will permit the continued operation of those projects approaching their economic limit under present price constraints.

Six, price relief for enhanced recovery crude oil should not penalize or "ratchet down" other categories of domestic oil production. Constraints of the composite weighted average pricing scheme should not be allowed to translate relief for one industry sector into injury for another.

Mr. Chairman, I would like to mention, too, that the funds appropriated through fiscal 1978 for the strategic petroleum reserve total \$3.1 billion, while the total projected by DOE for the first 750 million barrels of stored oil would be \$14.5 billion. The estimated total for 1 billion barrels would be \$20-plus billion. If these figures are wrong, I wish Mr. Langenkamp would correct me. Of this figure of \$20-plus billion, 14½ would be for the oil alone at \$14.50 a barrel. If that per-barrel figure is wrong, then that, of course, would change the arithmetic that we've used.

I would just make the quick point that we are willing, and I think justified, in having a strategic petroleum reserve program. I dissent in the amounts that we are spending this year, or authorizing, rather. But the strategic petroleum reserve is necessitated because of our inability to provide domestic energies in sufficient amounts to take care of our needs. And I think we should be just as concerned, and put it on just as much a crash basis, to remove the restrictions that exist on oil and gas generally, and particularly those that exist on secondary, tertiary, and all kinds of enhanced recovery oil.

I would hope that the Department Mr. Langenkamp works so ably for would come up with a program right away to provide for decontrol of oil from enhanced recovery operations, including waterflooding and other secondary methods.

Mr. Chairman, I firmly believe in the six principles for an enhanced oil recovery bill that I outlined earlier, and later today I will introduce into the Senate a bill which meets these qualifications. I ask that a copy of my bill be made a part of the hearing record, and that it be made a vehicle for consideration by this committee of price incentives for enhanced crude oil production. And I will, Secretary Langenkamp, provide you with a copy of my remarks and the proposed legislation.

Mr. Chairman, thank you very much.

Senator HASKELL. Thank you.

[The text of Senator Bartlett's bill, which was introduced subsequent to the hearing, follows:]

95TH CONGRESS
2D SESSION

S. 3306

IN THE SENATE OF THE UNITED STATES

JULY 17 (legislative day, MAY 17), 1978

Mr. BARTLETT introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

A BILL

To provide for increased crude oil production in the United States through the use of price incentives for enhanced crude oil recovery.

1 *Be it enacted by the Senate and House of Representa-*
2 *tives of the United States of America in Congress assembled,*
3 That this Act may be cited as the "Enhanced Crude Oil
4 Recovery Incentives Act".

5 SEC. 2. Section 8 of the Emergency Petroleum Alloca-
6 tion Act of 1973, as amended, is amended by adding the
7 following new paragraph:

8 “(k) (1) The first sale price of enhanced recovery
9 crude oil shall be exempt from the regulation promulgated
10 under section 4 (a) of this Act.

1 “(2) For purposes of this subsection, ‘enhanced recovery
2 crude oil’ means crude oil produced from any reservoir on a
3 property for which a bona fide enhanced recovery project,
4 consisting of the injection of fluids and/or other materials
5 into the reservoir for the purpose of increasing ultimate crude
6 oil recovery, has been implemented. Eligible enhanced re-
7 covery projects must be certified by the appropriate State
8 regulatory authority and shall include, but not be limited to,
9 waterflooding, chemical flooding, polymer flooding, miscible
10 fluid injection, steam injection, gas injection, in situ com-
11 bustion, and any variation or combination of the same. The
12 President shall have the authority to further define the term
13 by rule.

14 “(3) For purposes of this section, the President shall
15 include in the computation of the actual weighted average
16 first sale price of crude oil produced in the United States in
17 any month subsequent to the month of enactment of this sub-
18 section, the actual volume of enhanced recovery crude oil
19 and such actual volume shall be deemed to have been sold at
20 a first sale price which equals the average price for which
21 such crude oil would have been sold if the exemption under
22 this subsection had not been in effect.”.

Senator HASKELL. We'll hear Mr. Langenkamp.

STATEMENT OF DOBIE LANGENKAMP, DEPUTY ASSISTANT SECRETARY, RESOURCE APPLICATIONS, DEPARTMENT OF ENERGY; ACCOMPANIED BY DR. LISLE REED, OFFICE OF OIL AND NATURAL GAS SUPPLY AND DEVELOPMENT

Mr. LANGENKAMP. Thank you, Mr. Chairman. My name is Dobie Langenkamp with the Department of Energy. I have with me, Senator, Dr. Lisle Reed who heads the Office of Oil and Natural Gas Supply Development in the Department of Energy in resource applications. I will read a truncated version of our statement.

Senator HASKELL. Your full statement will be received in the record.

Mr. LANGENKAMP. And then answer any questions that you may care to pose.

I'm pleased to be here today to provide comments about enhanced oil recovery and the type of incentive programs that may be appropriate to encourage the use of EOR techniques.

Enhanced oil recovery offers our Nation considerable potential for additional energy supplies which will be critically needed to offset imbalances in supply and demand that we expect to occur in the late 1980's.

At the present time there are two bills under consideration by this committee which deal with the incentives necessary to encourage enhanced oil recovery. Both of these bills are thoughtful and appear to recognize the potential contribution which enhanced oil recovery can make toward increasing domestic crude oil production. Both offer special incentive programs designed to accelerate and increase the use of enhanced oil recovery processes.

The Department of Energy is equally cognizant of the potential for enhanced oil recovery and encourages the use of enhanced oil recovery processes.

The Department is currently involved in substantial research, development, and demonstration programs aimed at fostering EOR technology development. In fact, statistics will show that the Department of Energy, in fiscal year 1978, is expending approximately \$46 million in this regard.

Also, within the Department a commercialization strategy is presently being developed by a task force under the leadership of Under Secretary Dale Myers. The mission of the task force is to determine the potential for enhanced oil recovery, delineate the barriers that are impeding significant utilization of enhanced oil recovery processes, and analyze the options for removing those barriers.

Following completion of the task force effort, recommendations will be made identifying those programs which appear to be most desirable for the Government to pursue in increasing enhanced oil recovery production.

Although specific answers about the costs and benefits of various incentive programs are not available at this time, I will attempt to address the major issues concerning EOR.

The Department is of the opinion that approximately 300 billion barrels of oil remain in place after primary and secondary recovery practices. The Federal Energy Administration, ERDA, National

Petroleum Council, and the Office of Technology Assessment have all attempted to estimate the quantity of the remaining oil that could be produced by employing enhanced oil recovery techniques.

I noted this morning that none of the witnesses have disagreed on these rough parameters. Estimates indicate a range from 10 billion barrels to 50 billion barrels that could be recovered with EOR techniques. These estimates differ depending on assumptions of price and so forth. At the Department of Energy, we're operating under the assumption that on the basis of the best analysis to date, the range would be from 25 to 45 billion barrels of oil recoverable with EOR techniques.

This volume could be more than the present proved crude oil reserves in the United States of approximately 30 billion barrels. With proper inducement, we believe that our Nation could realize over 2 million barrels per day of oil production by 1990 from enhanced recovery techniques.

Once again, we agree with the general parameters that show the low estimate as one-half million barrels a day to the highest of about 2 million barrels a day, although, I think that the Office of Technology Assessment estimate was slightly above the 2-million-barrel-a-day estimate.

In considering the EOR potential, it is important to acknowledge that a large portion of the production and transportation infrastructure is already in place. Enhanced oil recovery will come from existing fields that are currently being produced. These fields are known and developed with gathering systems in place.

There are refineries already constructed and dependent on the type of crude oil produced from these fields. Labor needed for the field operation is generally in adequate supply. Realization of the full potential of EOR from these fields will, of course, require drilling some additional wells, installing additional equipment, and injecting various materials into the reservoir formations.

The state of the art associated with each of these EOR techniques is currently in different stages of development and each has a different degree of reliability. For instance, steam drive in shallow, heavy oil reservoirs is already commercially used although nontechnical barriers constrain the development of its full potential. Surfactant/polymer flooding in shallow, homogenous reservoirs also appears technically feasible, but may not be economically viable at today's prices.

The DOE, at the present time, has an ongoing research development demonstration program designed to improve EOR processes and demonstrate their application in challenging reservoirs. In fact, the Department of Energy has a research and development laboratory in Bartlesville, Okla., Senator Bartlett's home State, that has spent considerable time and money in developing these EOR techniques.

At the present time, over \$58 million has been budgeted for this R. & D. —

Senator HASKELL. I wonder, sir, if you could just go to your recommendations on the two bills. Time is passing here and we've got to stop at 12:30.

Mr. LANGENKAMP. Let me summarize it very briefly. The position of the Department of Energy now, Senator, is that we have a comprehensive task force effort underway which we refer to as the commercialization task force.

We're attempting to determine the proper incentives for not only oil and gas, but for shale and many other resources. The task force is in midstream. At the present time, we feel that it is premature to support or oppose legislation of the sort that has been set forth here. We would like to emphasize the following points:

First of all, we find that enhanced oil recovery does have the potential that the witnesses here today have testified to. We feel that an effort must be made to insure the development of enhanced oil recovery. We point to the effort that the Department has been involved in over the past year, the some \$50 million that's being spent in research and development as evidence of the Department's interest in enhanced oil recovery.

But at the present time, we feel that it is premature to advocate or sponsor either of these two bills under consideration by the committee. I'll read the summary from my statement.

In summary, the Department of Energy is presently analyzing various programs which would encourage enhanced oil recovery development. Several of these options could be implemented by regulatory changes. We feel it is premature to enact additional legislation pertaining to enhanced oil recovery and, accordingly, we cannot support the enactment of S. 2623 and 2999 at this point in time.

That concludes my statement.

[The prepared statement of Mr. Langenkamp follows:]

STATEMENT OF DOBIE LANGENKAMP, DEPUTY ASSISTANT SECRETARY, RESOURCE APPLICATIONS, DEPARTMENT OF ENERGY

Mr. Chairman and members of the committee, I am pleased to be here today to provide comments about enhanced oil recovery (EOR) and the type of incentive programs that may be appropriate to encourage the use of EOR techniques. Enhanced oil recovery offers our Nation considerable potential for additional energy supplies which will be critically needed to offset imbalances in supply and demand that we expect to occur in the late 1980's.

At the present time, there are two bills (S. 2623 and S. 2999) under consideration by this Committee which deal with the incentives necessary to encourage enhanced oil recovery. Both of these bills are thoughtful and appear to recognize the potential contribution which enhanced oil recovery can make toward increasing domestic crude production. Both offer special incentive programs designed to accelerate and increase the use of enhanced oil recovery processes. The Department of Energy is equally cognizant of the potential for enhanced oil recovery and encourages the use of enhanced oil recovery processes. The Department currently involved in a substantial research, development, and demonstration program aimed at fostering EOR technology development. Also, within the Department, a commercialization strategy is presently being developed by a task force under the leadership of Under Secretary Dale Myers. The mission of the task force is to determine the potential for enhanced oil recovery, delineate the barriers that are impeding significant utilization of enhanced oil recovery processes, and analyze the options for removing those barriers.

Following completion of the task force effort, recommendations will be made identifying those programs which appear to be most desirable for the Government to pursue in increasing enhanced oil recovery production. Although specific answers about the costs and benefits of various incentive programs are not available at this time, I will attempt to address the major issues concerning enhanced oil recovery.

ENHANCED OIL RECOVERY RESOURCE POTENTIAL

Approximately 300 billion barrels of oil remain in place after primary and secondary recovery practices. The Federal Energy Administration, Energy Research and Development Administration, National Petroleum Council, and the Office of Technology Assessment, have all attempted to estimate the quantity of the remaining oil that could be produced by employing enhanced oil recovery

techniques. Estimates indicate a range of from less than 10 billion barrels of oil to more than 50 billion barrels of oil may be recovered through enhanced recovery techniques. These estimates differ depending on assumptions of price, technology development, and a number of other variables. We believe in light of the analysis, performed to date, that a range of 25 to 45 billion barrels of oil may be recoverable using EOR techniques. This volume could be more than the present proved crude oil reserves of approximately 30 billion barrels. With proper inducement, we believe that our Nation could realize over 2 million barrels per day of oil production by 1990 from enhanced recovery techniques.

When considering the enhanced oil recovery potential, it is important to acknowledge that a large portion of the production and transportation infrastructure is already in place. Enhanced oil recovery, for the most part, will come from existing fields that are currently being produced. These fields are known and developed with gathering systems in place. There are refineries already constructed and dependent on the type of crude oil from these fields. Labor needed for field operation is generally in adequate supply. Realization of the full potential of enhanced oil production from these fields will, of course, require drilling some additional wells, installing additional equipment, and injecting various materials into the reservoir formations. A further advantage of prompt exploitation of enhanced oil techniques is the fact that once fields are depleted and the wells plugged, the possibility of successful enhanced oil recovery is reduced.

CURRENT ENHANCED OIL RECOVERY ACTIVITIES

Enhanced oil recovery techniques can be broken into three major categories: (1) Thermal processes which include steam drive, cyclic steam, and in situ combustion are processes wherein heat is applied to decrease the viscosity and increase the mobility of the oil in the reservoir; (2) Miscible gas processes which include hydrocarbon miscible and carbon dioxide miscible are processes involving the injection of fluids that dissolve the oil retained in the reservoir, forming a single oil-like liquid that can flow through the reservoir more easily than the original crude; and, (3) Chemical processes which include surfactant-polymer flooding caustic flooding and polymer augmented waterflooding, involve the injection of materials that modify the chemical and physical interaction of oil with its surroundings, thus increasing the mobility of the oil.

The state of the art associated with each of these techniques is currently in a different stage of development, and each has a different degree of reliability. For example, steam drive in shallow, heavy oil reservoirs is already commercially used although non-technical barriers constrain the development of its full potential. Surfactant/polymer flooding in shallow, homogeneous reservoirs, also appears technically feasible, but may not be economically viable at today's prices.

Table 1 shows the status of enhanced oil recovery in the United States. The first three columns represent the number of active projects by process in 1973, 1975, and 1977. The fourth column shows the number of new projects being proposed and the fifth column provides an estimate of current production by technique. Cyclic steam projects have been omitted because they have been frequently utilized for a number of years and are considered a secondary means of recovery.

TABLE 1.—ACTIVE U.S. EOR PROJECTS

	1973	1975	1977	Proposed projects	Current production (barrels per day)
Steam drive.....	22	31	43	10	128,000
In situ combustion.....	19	21	16	8	10,000
Surfactant-polymer.....	7	13	22	4	400
Polymer.....	9	14	21	3	2,600
Caustic.....	2	1	3	1	(1)
Hydrocarbon miscible.....	12	15	15	0	20,000
Carbon dioxide.....	6	9	14	4	40,000
Total.....	77	104	134	30	201,000

¹ None reported.

Since 1974, a total of 21 of these projects have been funded by DOE programs.

GOVERNMENT SPONSORED RESEARCH AND DEVELOPMENT ACTIVITY

The DOE has an ongoing research, development and demonstration program designed to improve EOR processes and demonstrate their application in challenging reservoirs. This program is a joint, cost-shared activity with industry that seeks to focus on major technological problems. A summary of projects funded to date are given in Table 2 below.

TABLE 2.—ENHANCED OIL RECOVERY FIELD-TEST CONTRACTS SUMMARY

[Dollars in millions]

	Projects	DOE	Industry	Total	DOE percent of cost
Surfactant polymer.....	6	31.9	51.9	83.8	37
Carbon dioxide.....	4	5.2	8.5	13.7	38
Improved waterflood.....	5	10.5	18.6	29.1	36
Thermal recovery.....	6	10.4	22.9	33.3	31
Total.....	21	58.0	101.9	159.9	36

In addition to the development program just discussed, there is an active Government laboratory research program located in Bartlesville, Oklahoma.

MAJOR PROBLEMS CONFRONTING THE USE OF ENHANCED OIL RECOVERY PROCESSES

As Table 1 indicates, the EOR process currently making the greatest contribution is steam drive, specifically steam drive in shallow, heavy oil reservoirs. However, air quality standards will place restrictions on the expansion of steam injection operations in California and probably in other states. Expansion of steam drive operations will require accommodations of air quality regulations, and development of cleaner-burning steam generators.

The major problem facing the other enhanced oil recovery techniques is the lack of knowledge of the reservoir performance. Reservoirs are different in thickness, depth, size, porosity, and permeability. The reservoir fluids also differ in mobility, surface tension, and gravity. All of these factors result in uncertainty in forecasting specific reservoir performance and project profitability.

In order to reduce these uncertainties, operators generally perform technical pilots and economic pilots in most fields. The technical pilot will usually involve a limited number of wells and cover a small area. Its purpose is to determine if the enhanced oil recovery technique will actually recover additional oil. An economic pilot will usually consist of more wells, but will still represent a small percentage of the total field. The economic pilot will give an indication of the expected recovery and economies of scale for full field development by the particular enhanced oil recovery process.

Performing the various pilots in oil fields today is a necessary means of testing reservoir performance, decreasing major uncertainty, and projecting the application of the enhanced oil recovery techniques. The testing of a field is a process that requires several years and even with large incentives for enhanced production, a substantial delay will occur before most fields can be brought into full scale enhanced oil development. Nevertheless, because of the pilots conducted to date, there are several fields in the United States that are potential candidates for full field commercialization during the next few years.

OPTIONS FOR GOVERNMENT PROGRAMS

The Government may continue to sponsor research pilot projects by offering cost share programs as it has for the past few years. Pilot projects might also be encouraged by altering present price regulations to favor initiation of both technical and economic field pilots. The number of pilots initiated would be a function of the incentives provided for conducting them.

There are several incentive approaches that could be devised for encouraging full field development for enhanced oil recovery processes. The Bentsen and Hart Bills (S. 2623 and S. 2999) under consideration by this Committee offer such programs for sponsoring full field development.

The Bentsen Bill (S. 2623) proposes to release all controlled oil produced from a property from price controls when a qualified enhanced oil recovery process has

been employed on such properties. Such a program would give substantial incentives for many operators to utilize enhanced oil recovery processes. Under this type of proposal, current primary and secondary oil production from a property would be released from price controls upon the implementation of an EOR project on the property. Thus, the EOR project operator would receive cash flow attributed to the additional production resulting from the employment of a qualified EOR technique as well as cash flow resulting from the decontrol of existing primary and secondary production from the property in question. Accordingly, situations may occur where operators would realize unjustifiably high rates of return.

Our major concern with giving such a program is that some enhanced oil recovery projects would be initiated without conducting proper and prudent technological study and development to accord with maximum reservoir recovery. Also, the cost to the public and the revenues to the producer resulting from such an incentive may in some cases be substantially greater than the benefits derived from increased production and greater than necessary to actually stimulate many projects. In fact, certain operators may be encouraged to install anything that would qualify as an enhanced oil recovery process so as to release from price limitations all controlled oil from their property. Finally, there are a number of administrative problems that would be introduced, such as determining the time at which production would be released, maintaining consistency of individual State interpretations and establishing criteria for a valid EOR project.

The studies being conducted in the Department of Energy at the present time should indicate the costs and benefits of the type of program proposed in S. 2623 as well as alternative incentive plans. Although we do not see the need for the extent of economic stimulus that the incentive package proposed in S. 2623 would provide, we do see merit in the concept of providing higher prices for quantities of controlled oil based on enhanced oil recovery investments. Several of our program alternatives now under study in the Department of Energy are variations of this concept.

The Hart Bill (S. 2999) is a bill that would provide for:

loan guarantees for independent operators;

price guarantees of up to \$25 per barrel for full field development of a limited number of projects; and,

world price for incremental enhanced oil production from all other projects.

We do acknowledge that there may be significant negative cash flows during the first few years for some enhanced oil projects. Given the uncertainty of project economies, some mechanism may be needed to generate investment capital for some independent operators. S. 2999 addresses this issue by way of a loan guarantee program. We feel that there are alternative methods which should be evaluated before the adoption of loan guarantees. One of our objectives at the present time is to verify the need for a loan guarantee program or some alternative program and to determine what specific criteria should be utilized in such a program.

The purpose of the enhanced oil recovery price guarantee program is apparently to provide an incentive for a limited number of operators to initiate full field enhanced oil recovery development utilizing various enhanced oil recovery processes that are not, presently, considered commercial. After employment of the various enhanced oil recovery technologies on a commercial scale, it is presumed that other commercial scale projects will be initiated without subsidization. The Department of Energy concedes that the full field utilization of various enhanced oil recovery processes may contribute to advancing technology. However, our present judgment is that the Bill would not significantly contribute to the number of full field utilization projects. Furthermore, \$25 per barrel exceeds the price that is needed to sponsor full field development of varying technologies in the best candidate fields in the country today.

As I noted earlier, some commercial development of enhanced oil recovery processes was initiated at prices lower than the current oil prices. There are plans by some companies to initiate full field enhanced oil recovery projects at the world oil price level for only the incremental production resulting from the project. Where increased prices are required, they may still be substantially less than the \$25 per barrel prescribed by S. 2999. The needed incentive could be provided through the regulatory mechanism of releasing a certain additional portion of crude oil production to higher price levels.

In summary, the Department of Energy is analyzing various programs that would encourage enhanced oil recovery development. Several of these options could be implemented by regulatory changes. We feel it is premature to enact additional legislation pertaining to enhanced oil recovery and, accordingly, we cannot support the enactment of S. 2623 and S. 2999 at this time.

This concludes my formal comments. I would be pleased to try to answer any questions the Committee may have at this time.

Senator HASKELL. OK. Mr. Secretary, I've just got three questions. I have a number of other questions that I'm going to submit in writing which I would hope you would be able to answer within 10 days.

The Congressional Budget Office estimated that your COET tax would save about 200,000 barrels a day. Now we've got testimony that tertiary recovery at current world prices could add one-half to 1 million barrels per day by 1985.

Now doesn't this suggest that from a balance of payment standpoint tertiary recovery is more important than COET?

Mr. LANGENKAMP. Well, Senator, I don't think—they are necessarily exclusive——

Senator HASKELL. Well, if you have to have one or the other, which would you have?

Mr. LANGENKAMP. I don't think we do.

Senator HASKELL. I said if you had to have one or the other, which would you have?

Mr. LANGENKAMP. Senator, the fact that you put the 200,000 barrels a day figure on COET and the fact that——

Senator HASKELL. The Congressional Budget Office did, I didn't.

Mr. LANGENKAMP. The 500,000 barrels per day on tertiary recovery, we feel, can be achieved without extraordinary measures. We feel that the 2 million barrel a day minimum level would probably require an extra effort.

But as far as the 500,000, I think that this probably could be achieved under our present R. & D. policy.

Senator HASKELL. Well, you indicate basically that you're studying this thing. And you've really been studying it. This isn't a personally directed remark. But for 2 years the executive branch of the Government has been studying it.

Now in August of 1977 you put a notice in the Federal Register saying that you were going to have regulations. Now why the devil did you put a notice in saying you were going to have regulations without having regulations I don't know. But the fact is, the only thing you've done so far, as far as we can see, you put a notice in August 1977, saying you're going to have regulations. This is a year later or practically a year later.

So I think that speaking for myself, and I probably don't share all the views of Senator Bartlett and he and I know we don't share all the views. In fact, on this subject this may be unique. But I——

[Laughter.]

Senator HASKELL [continuing]. Just cannot understand why the Department is still studying this. It doesn't impress me one little bit that a task force is at work.

I will submit my questions for the record.

Mr. LANGENKAMP. Well, let me make just this one comment. I don't think that's an unreasonable response, and it sure wasn't a surprise to me that I received it this morning.

[Laughter.]

But let me say that this matter of commercialization is more complex if one is attempting to balance the interest of varying sources

of energy. Now the bill that we are discussing this morning may be quite thoughtful with regard to oil and gas, but they do have a price tag, each one of them. They vary and each portion of them has a price tag.

But we've also got the shale matter, as you're fully aware. And we've got the commercialization there and we've got all the other forms of energy ranging from the more exotic down to coal. To balance the price tag to the taxpayer and consumer in a rational way is difficult. Many of the arguments that could be made for one resource can be made for another.

I think the Department is acting in a responsible way in approaching commercialization across the board, even though it may, in the area of oil and gas which is an area that I'm involved in, appear that it's acting less rapidly than those who have proposed these bills would like it to act.

Senator HASKELL. OK. Thank you, sir. Senator Bartlett.

Senator BARTLETT. Mr. Chairman, I congratulate you for your comments and statement, and I'm very happy that we do agree on this matter. I think we've agreed on several over the last 5½ years. And I hope there will be more in the remaining months that we'll be here.

Mr. Langenkamp, I will be covering some of the same ground but I will try to take it maybe a little further.

The Energy Conservation Production Act of 1976, ECPA, directed the administration to come up with a program of price incentives for enhanced oil recovery. We've heard that promulgation of such regulations is imminent. When can we expect to see those regulations?

Mr. LANGENKAMP. Well, as I'm sure you're aware these regulations have been published as proposed rulemakings although they have not been published in final form. Now, I can't, at this time, give you any indication as to when those regulations will be published in their final form. Although, I'm sure you're aware that from the Department of Energy's standpoint, we must consider the national energy program as a unitary whole.

There is inevitably a relationship between all of the programs, all of the incentive programs, in the overall energy policy that appears deadlocked at this time.

Senator BARTLETT. Mr. Langenkamp, is it true that they have been prepared and awaiting the Secretary's approval since late last year?

Mr. LANGENKAMP. I couldn't answer that, Senator Bartlett. The Economic Regulatory Administration is responsible for the preparation of regulations and I'm not sure what the status of those regulations are.

Senator BARTLETT. What is the total amount of money that has been spent to date on the strategic petroleum reserve?

Mr. LANGENKAMP. Senator Bartlett, I appreciate your kind words about the strategic petroleum reserves because it is a program that I am involved in. It's difficult to say at this point in time exactly how much has been spent.

We have over 30 million barrels of oil in the ground. Our average price has been \$13 to \$13½ a barrel for that oil. Our storage costs are roughly \$2 a barrel and are probably greater than \$60 million at this time because we have some capacity that we have yet to fill. The sum

is substantial and it will increase between now and the end of the year when we hope to have over 100 million barrels in the ground.

Senator BARTLETT. What is the estimated total for 1 billion barrels?

Mr. LANGENKAMP. Well, if we went to 1 billion and did not utilize any alternative financing device such as industrial storage or anything else, you would have 1 billion times the average cost of the oil plus our estimated cost for storage which is still only \$2 a barrel. You can calculate for yourself what the rough cost of 1 billion barrels of strategic petroleum reserve would be.

There are options available to us that would reduce that cost. But if it were all stored in presently contemplated salt dome storage the cost would be close to the figures that you set forth earlier.

Senator BARTLETT. If the American people are willing to spend this amount of money to buy foreign oil to guard against the interruption of foreign oil imports, the necessity of which is the result of declining domestic production, wouldn't they be even more willing to spend that money to develop and produce more secure reserves of petroleum here at home?

In other words, solving the problem rather than just dealing with a symptom without a solution?

Mr. LANGENKAMP. You probably could estimate what the people would prefer to do better than I could. I would say this, though; we're talking about separate problems. The strategic petroleum reserve is designed to have a 3-million-barrel-a-day drawdown. So that in the event of an interruption of supply, you would have approximately 3 million and as much as 6 million barrels a day of drawdown capability.

What we're talking about with EOR is increasing U.S. domestic oil production by as much as 1 million barrels a day and if we were to realize the highest projections that any witness here today testified to, it may be 2 million barrels a day. Even with this production, we would still have considerably less domestic production than domestic need. We might be able to reduce imports by 2 million barrels, but we would still have an import shortfall of approximately 5 million barrels a day.

So I think that these are separate issues.

Senator BARTLETT. I think they're separate, but isn't it more important to solve the problem? Or isn't it also important to solve the problem?

Mr. LANGENKAMP. It is important to solve the problem.

Senator BARTLETT. The administration's apparent-enhanced oil recovery plan is intended to prevent the producer from making a windfall profit if he succeeds, but to force him to absorb a windfall loss if he fails. How can you expect an operator to take the enormous risk inherent in such expensive projects under your proposal?

Mr. LANGENKAMP. Well, I think that if I could summarize the attitude of the Department of Energy, it is that incentives are needed to encourage and increase the production of oil tertiary needs.

At the same time, the Department isn't prepared to sponsor any particular incentives at this point in time.

Senator BARTLETT. I thank the Deputy Assistant Secretary. Thank you, Mr. Chairman.

Senator HASKELL. Well, thank you very much, Mr. Secretary. There will be written questions which I hope you'll answer.

[Subsequent to the hearing, Mr. Langenkamp supplied the following:]

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C., July 20, 1978.

MR. R. DOBIE LANGENKAMP,
Deputy Assistant Secretary, Oil, Natural Gas and Shale Resources, Resource Applications, Department of Energy, Washington, D.C.

DEAR MR. LANGENKAMP: At the July 17 hearing of the Committee on Energy and Natural Resources, there was not enough time to discuss a number of issues which are relevant to the subject. Accordingly, I am enclosing a set of supplemental questions which I hope can be answered for the record.

I look forward to receiving your responses to supplemental questions. In order to expedite printing of the hearing record, these responses should be provided by close of business, August 4, 1978.

Questions about this request should be directed to Benjamin S. Cooper or James T. Bruce at 224-9894.

Sincerely yours,

FLOYD K. HASKELL,
U.S. Senator.

SUPPLEMENTAL QUESTIONS—COMMITTEE ON ENERGY AND NATURAL RESOURCES

1. President Carter's Energy Program described in a White House release of April 20, 1977, provided for removal of price controls from incremental tertiary recovery in old fields.

Has the Administration changed its mind on this part of the National Energy Program?

2. What has been the reason for the Department's delay in issuing final rules for tertiary recovery projects as required by section 122 of the Energy Conservation and Production Act (Public Law 94-385) and as proposed by the FEA in August, 1977 (42 FR 41572)?

3. What are your estimates of the amount of domestic production which will be covered by the deregulation provisions of S. 2623 and S. 2999 in each year between now and 1985?

What amount of additional revenues to oil producers will result from adoption of these bills? Indicate how much of this revenue will accrue directly to producers instituting tertiary recovery and also what will be the impact on producers generally as a result of removal from the composite price calculation of volumes subject to the exemption.

4. What is the meaning of the concept of a crude oil producing property in current DOE regulations? Can a property encompass several wells? reservoirs? fields?

5. Please supply the Committee with a list of fields with significant enhanced oil recovery (EOR) potential showing the amount of working interest and the amount of royalty interest in each owned by the major oil companies.

6. How would DOE interpret the phrases "new and improved" (proposed sec. 20(b) of Public Law 93-577 in S. 2999) and "first of a kind" (proposed sec. 20(d)(2) of Public Law 93-159 in S. 2999) EOR operations:

(a) First field-wide program?

(b) First generation (5 years experience) with such projects?

(c) some other interpretation?

7. What EOR technologies have been demonstrated on a field-wide basis?

8. Which is the larger risk in EOR operations?

(a) that the process will or will not work? or

(b) that the process will not work in the context of a given reservoir?

Which of these risks is best addressed by S. 2999 and S. 2623?

9. Carbon dioxide is an important chemical for some forms of tertiary recovery. What is the supply situation for CO₂?

10. According to the OTA report on "Enhanced Oil Recovery Potential in the U.S." the most important legal obstacle, aside from price controls, is the absence of a compulsory unitization statute in Texas and the ineffectiveness of the compulsory unitization statute in California. Would the Administration favor legislation encouraging or mandating compulsory unitization, as these two states have one half the nation's potential opportunity for enhanced recovery?

11. Who would be responsible for monitoring and enforcement to prevent fraud or other violations of the pricing provisions of S. 2999 or S. 2623?

12. What criteria would the Secretary use to determine that "the environmental impacts directly resulting from the proposed operation have been fully evaluated by the borrower" (proposed section 22(a)(6) of Public Law 93-577 in S. 2999)?

13. What evidence indicates that uncertainty that loans will be repaid (rather than doubt about the size of return on investment) is causing a shortage of capital for investment to prove tertiary recovery techniques?

14. What amount of additional revenues will accrue to oil producers as a result of the amendment proposed by Senator Bartlett at the July 17 hearing? (A copy of the amendment is attached.)

AUGUST 9, 1978.

Hon. FLOYD K. HASKELL,
U.S. Senate,
Washington, D.C.

DEAR SENATOR HASKELL: This is in response to your letter of July 20, 1978, wherein you requested additional information concerning enhanced oil recovery. A response has been provided to all questions, but in some instances, it was necessary to make some very gross assumptions.

As you are probably aware, shortly after I testified before your Subcommittee the Department of Energy published final rulemaking which will allow world price for incremental production resulting from the employment of qualified enhanced oil recovery techniques. We are also giving consideration to further rulemaking which will address the problem of capital availability for EOR projects.

It is our intention, and I am sure that of the Congress also, to see that major problems inhibiting domestic energy production are resolved. We hope that our programs will result in encouraging significant enhanced oil recovery production.

I personally appreciated the courtesy shown me by you and the Subcommittee at the time of my testimony.

Inquiries concerning the enclosed responses may be directed to J. Lisle Reed or Ira Mayfield at 566-7425.

Sincerely,

(Signed) R. DOBIE LANGENKAMP,
Deputy Assistant Secretary,

Oil, Natural Gas and Shale Resources, Resource Applications.

Enclosure.

1. President Carter's Energy Program, described in a White House release of April 20, 1977, provided for removal of price controls from incremental tertiary recovery in old fields.

Has the Administration changed its mind on this part of the National Energy Program?

No we have not. The final rulemaking on additional price incentives for tertiary enhanced recovery techniques was signed by Economic Regulatory Administration Administrator David J. Bardin on July 26, 1978, to become effective September 1, 1978. As part of this final rule, there was a notice of continuation of rulemaking, request for further comments and public hearing concerning possible further incentive measures for certain tertiary enhanced recovery projects. A copy of this rule is attached.

We should note that, as indicated in the attached Notice, incremental tertiary production is not exempt by statute from price controls, although our regulations provide that qualifying tertiary production is permitted to receive a market-clearing price. The actual selling price of this category of crude oil must be included in calculating the composite price for domestic crude oil under section 8 of the EPAA.

2. What has been the reason for the Department's delay in issuing final rules for tertiary recovery projects as required by Section 122 of the Energy Conservation and Production Act (Public Law 94-385) and as proposed by the FEA, in August, 1977 (42 FR 41572)?

In the August 1977 Notice, FEA recognized the extreme difficulty of reconciling all of the competing considerations involved in determining the proper scope of the tertiary recovery incentive program. Among the most difficult of these issues was the question, raised in the January 1977 Notice of Proposed Rulemaking and commented on extensively, of whether the incentive price should be limited to incremental tertiary production only, or whether some amount of production occurring prior to the tertiary production response should receive higher prices in order to permit adequate capital formation and/or reduce the risks for projects requiring heavy "front-end" investment.

Despite the decision in the August Notice that incentive prices should be tied to incremental production resulting from the tertiary project, at least in this experimental stage of the program, we remained concerned about whether limiting the incentive price to incremental production at the time it is produced will provide adequate incentives for those projects that are very high-risk and that require very substantial investment of expenditures prior to any production response. Our further consideration of this issue caused some delay. We ultimately decided, in the interests of time and the desire to receive more detailed comments directed specifically at the "front money" issue, to issue a final rule implementing the August Notice and also to reopen on a limited basis the decision set forth in the August Notice by proposing that, in the case of certain high-cost, high-risk projects, the producer would be allowed to "release" some current production to higher prices, provided this amount is "paid back" in the form of foregoing the incentive price for incremental production until the pay-back has been completed. We are continuing this rulemaking proceeding to obtain further written comments on this proposal, and we have also scheduled an additional public hearing for this purpose.

We also have been desirous of establishing close coordination and cooperation with the various state regulatory bodies and to obtain their assistance in the application review procedure. Laying the general groundwork for this procedure has taken some time, as has the need to establish our own internal procedures for processing and reviewing applications.

3. What are your estimates of the amount of domestic production which will be covered by the deregulation provisions of S. 2623 and S. 2999 in each year between now and 1985?

What amount of additional revenues to oil producers will result from adoption of these bills? Indicate how much of this revenue will accrue directly to producers instituting tertiary recovery and also what will be the impact on producers generally as a result of removal from the composite price calculation of volumes subject to the exemption.

In addressing either S. 2999 or S. 2623, one has to assume, among other things, the success of EOR techniques and the motives and assumptions of oil field operators. In addition to these items, the amount of upper tier and lower tier oil would have to be known for each project that may go forward. Obviously, the answer to this question cannot be stated accurately at this time. However, in an attempt to be responsive, we will make certain gross assumptions and estimate production and revenue impacts. The response to this question could vary considerably depending on the assumptions utilized.

ASSUMPTIONS

Current enhanced oil recovery (EOR) production is 380,000 barrels per day including about 120,000 barrels per day from steam soak methods.¹ The distribution of this oil is assumed to be 50 percent lower tier and 50 percent upper tier.

EOR production under present world prices and technologies is expected to be 500,000 barrels per day in 1985. This is the presumed released production for S. 2999.

The amount of EOR production resulting under the pricing provisions of S. 2623 and current technology is estimated to be 1,000,000 barrels per day by 1985. (It was noted in the OTA Report titled, "Enhanced Oil Recovery Potential in the United States," January 6, 1978, that approximately 900,000 barrels per day of EOR production could probably be realized by 1985 using current technology and \$22 per barrel. We believe the incentives provided by S. 2623 would be in this range.)

Under S. 2623, a large incentive exists to install tertiary projects to release controlled oil regardless of the magnitude of the incremental EOR production. In light of this, it is assumed that at least 50 percent of all lower tier oil and at least 25 percent of all upper tier oil would be released from controls by 1985 under S. 2623.

Current price controls would remain in existence until 1985. Also constant oil prices are assumed.

The estimates of the amount of domestic production which will be covered by the deregulation provisions of S. 2623 and S. 2999 between 1978 and 1985 are as follows:

¹ Not clear whether S. 2999 means to include or exclude steam soak, although S. 2623 would expressly include it.

Year	Released oil (1,000 bbl/d)							
	S. 2999				S. 2623			
	Lower tier	Upper tier	New EOR	Total	Lower tier	Upper tier	New EOR	Total
1978.....	190	190	-----	380	190	190	-----	380
1979.....	190	190	10	390	200	200	20	420
1980.....	190	190	20	400	450	250	40	740
1981.....	190	190	40	420	700	340	80	1,120
1982.....	190	190	60	440	950	430	140	1,520
1983.....	190	190	80	460	1,200	520	240	1,960
1984.....	190	190	100	480	1,450	610	400	2,460
1985.....	190	190	120	500	1,700	700	620	3,020

The gross revenues to operators as a result of S. 2999 would be the current amount of lower tier and upper tier oil produced by EOR methods that would be released from price controls. The gross revenues under S. 2999 resulting from additional EOR production beyond today's current level are not estimated to be any different than those occurring under present regulations. In other words, the primary difference between the gross revenues under S. 2999 and the present regulations is that S. 2999 would provide for the release of present EOR production from price controls whereas present regulations only provide the higher price to additional ECR production.

It is recognized that removing the increment of EOR production from the composite price controls which would be offered by S. 2999 would provide more stability to the system and assurance to the operator of realizing actual world price for oil without adversely affecting other controlled oil production. We have not tried to quantify the slight EOR production difference that might result from this aspect. Thus, the gross additional revenues that may result from the decontrol provisions of S. 2999 are approximately as follows:

IMPACTS RESULTING FROM S. 2999

Year	Released oil (1,000 bbl/d)			Gross revenues (dollars in millions)		
	Lower tier	Upper tier	EOR production over base	Released lower tier at \$8.50/bbl	Released upper tier at \$2/bbl	Total gross revenues
1978.....	190	190	-----	590	140	730
1979.....	190	190	-----	590	140	730
1980.....	190	190	-----	590	140	730
1981.....	190	190	-----	590	140	730
1982.....	190	190	-----	590	140	730
1983.....	190	190	-----	590	140	730
1984.....	190	190	-----	590	140	730
1985.....	190	190	-----	590	140	730

The gross revenues resulting from S. 2623 would occur from releasing controlled oil from properties that would be subjected to EOR processes and from the additional EOR production above the present (world price) case. The estimated gross revenues resulting from S. 2623 are shown in the attached table. (These gross revenues are subject to operating costs, royalty payments, as well as State and Federal taxes.)

Releasing tertiary production from the composite price controls would, in principle, benefit all oil producers. If tertiary production is given special pricing incentives and the production resulting therein is left inside the composite, the prices and revenues realized might at some time require a reduction of prices and revenues of some one or more categories of domestic crude oil production in order to comply with section 8 of the EPAA.

Year	Released oil (1,000 bbl/d)			Gross revenues (dollars in millions)			
	Lower tier	Upper tier	EOR production over base	Released lower tier at \$8.50/bbl	Released Upper tier at \$2/bbl	Additional EOR production at \$14	Total gross revenues
1978	190	190		590	140		730
1979	200	200	10	620	150	50	820
1980	450	250	30	1,400	180	100	1,680
1981	700	340	40	2,170	250	200	2,620
1982	950	430	80	2,950	310	410	3,670
1983	1,200	520	160	3,720	380	820	4,920
1984	1,450	610	300	4,500	450	1,530	6,480
1985	1,700	700	500	5,270	510	2,560	8,340

4. What is the meaning of the concept of crude oil producing property in current DOE regulations? Can a property encompass several wells? reservoirs? fields?

"Property" is the right which arises from a lease or from a fee interest to produce domestic crude oil. Such leases or fee interests typically describe the right to produce by surface boundaries, although they may also delineate particular underground strata to which rights are conferred.

One of the underlying concepts of the Emergency Petroleum Allocation Act of 1973 and, later, of the Energy Policy and Conservation Act of 1975, is to monitor and control crude oil prices while still encouraging increased domestic crude oil production. Comparing the prior production from a property versus the current production from that property indicates whether this dual goal has been accomplished. Property, therefore, is the productive entity with respect to which crude oil production is measured to determine the appropriate classification as "old," "new," "released," or "stripper" oil.

It is also possible to segregate or aggregate initial rights to produce for purposes of delineating a producing property. Certain guidelines are in effect, for example, with respect to "unitized properties," which are properties that have been combined pursuant to a unitization agreement approved by the applicable state governmental regulatory authority in order to maximize the benefits of an enhanced recovery project.

More complex issues are posed with respect to the extent to which a tract subject to a single right to produce may appropriately be subdivided to form separate properties. One such example is that of noncontiguous tracts, where a single right to produce may be undifferentiated between tracts very distant from one another. Another example is that of very large tracts where exploration and development have been exercised on only certain specified areas, each constituting a separate geological structure, as compared to development of the entire tract. DOE has concluded that noncontiguous tracts and separate geological structures under very large tracts (as opposed to separate geological formations) subject, to the same right to produce, which have been developed and produced separately, and which have historically and consistently been accounted for as separate properties, may continue to be so regarded. It is also possible that a single right to produce may be segregated into separate properties due to severance tax or royalty owner accountability.

The most complex issue with respect to segregation of a property subject to a single right to produce has to do with production from separate "reservoirs." A property which contains multiple reservoirs but which is subject to a single right to produce may not, simply by virtue of the existence of separate reservoirs, be treated as comprising multiple properties. However, effective September 1, 1976, the definition of property was amended to recognize as a separate property each separate and distinct producing reservoir underlying a tract, to the extent that each reservoir is recognized by the appropriate state regulatory body, and production has been consistently and historically so reported.

A property usually encompasses more than one well, but may consist of only one well.

As defined above, a property *may* encompass two or more reservoirs under a single lease, or, these reservoirs may be considered two or more properties if recognized by appropriate state regulatory bodies and production has been consistently and historically so reported. The method of treatment in the latter instance is at the option of the operator.

A property may encompass a field if the field is small or in cases where a whole field is unitized for production purposes of secondary or tertiary recovery applications. Details and references to property definitions may be found in "Federal Energy Guidelines," paragraphs 16,055, 16,065 Part I and 16,066.

Finally, major oil companies were defined using the S. 2999 definition as those companies with at least 25,000 barrels daily oil production. Using Table 9 of the "31st Annual Report Survey," (of some 150 Oil and Gas Companies) from Energy Publications as a guide, this definition covered 33 companies.

Listing of EOR field and operator data

	Percent operated by majors
I. California:	
Belridge South.....	32
Coalinga.....	93
Coles Levee N.....	100
Cymric.....	98
Kern River.....	98
Mt. Poso.....	95
McKittrick.....	98
Elk Hills.....	100
Kern Front.....	79
Cat Canyon.....	94
San Ardo.....	100
Ventura.....	98
Brea Olinda.....	80
Inglewood.....	98
Long Beach.....	65
Richfield.....	97
Wilmington.....	12
II. Louisiana:	
Caddo Pine.....	29
Haynesville.....	95
Avery Island.....	100
Weeks Island.....	100
II. Texas:	
Fairway.....	0
Stephens Co. Regular.....	53
Crossett.....	96
N. Cowden.....	89
Howard-Glascock.....	73
Keystone.....	68
Parks.....	94
Sand Hills.....	91
Kelly-Snyder.....	99
Levelland.....	69
Salt Creek.....	0
Slaughter.....	91
Wasson.....	92
Wichita Co. Regular.....	42
Block 31.....	99
Hawkins.....	97
IV. Oklahoma:	
Stroud.....	74
Sho-Vel-Tum.....	81
V. Arkansas: Smackover.....	52
VI. Wyoming:	
Hilight.....	3
Salt Creek.....	95
VII. Colorado: Rangely.....	99
VIII. New Mexico: Vacuum.....	97
IX. Illinois:	
Salem Consolidated.....	98
Main Consolidated (Robinson).....	89

NOTE.—The data listed here are field operator data and not ownership data.

5. Please supply the Committee with a list of fields with significant enhanced oil recovery (EOR) potential showing the amount of working interest and the amount of royalty interest in each owned by the major oil companies.

We do not have comprehensive information on working interest or royalty interest of the majors in each field. However, we do have information on companies operating in each field and their production levels. This information is presented in the following table. The list of fields having significant EOR potential includes the 300 largest oil fields in which some EOR activity has already been undertaken or, in which the area has been identified as a high priority candidate under advanced EOR technology in previous ERDA, FEA, OTA, and NPC studies.

The 1975 FEA Survey of Oil and Gas Field Operators was used to develop the information on the major companies operating in each field. This survey asked individual operators to report their oil and gas production by state by field for the years from 1970-74. The oil production data were used to derive the percent of field production in 1974 produced by the majors. (Information on working interest and royalty interest is not available from this survey.) It should be kept in mind that the survey data may not have total coverage for each field and thus may not have all companies operating in the field. The percentages derived using the survey must be considered approximate.

6. How would DOE interpret the phrases "new and improved" (proposed sec. 20(b) of Public Law 93-577 in S. 2999) and "first of a kind" (proposed sec. 20(d)(2) of Public Law 93-159 in S. 2999) EOR operations:

- (a) First field-wide program?
- (b) First generation (5 years' experience) with such projects?
- (c) Some other interpretation?

In general, DOE would interpret the quoted phrases in a manner designed to be consistent with the overall context and perceived purposes of the legislation, having reference to the structure and language of the legislation and to any available legislative history. However, we do not believe that it would be prudent to adopt any fixed, categorical definitions or interpretations of these phrases at this time. Rather, we would be disposed to allow the content of these concepts to evolve through case-by-case determinations and/or to adopt general standards as a result of rulemaking proceedings utilizing public notice and comment procedures.

It should be noted that these phrases appear in provisions which establish a largely discretionary authority in the Secretary to provide loan or price guarantees with respect to enhanced oil recovery (EOR) operations. Proposed section 20(d)(2) of P.L. 93-159 in S. 2999 does mandate that the Secretary shall consider the extent to which the EOR project needs to be or has been demonstrated as commercially viable in determining whether to provide a price guarantee; but this criterion is not the only one that might be applied in making such determinations. Based upon a perceived purpose of this legislation to stimulate EOR activities that would not occur in the absence of these special benefits, we would be disposed to interpret the quoted phrases in a manner which takes account of the nature and degree of the unknowns presented by a given operation, with respect to the novelty of the technique being applied and also possibly with respect to the novelty of its application (or the scope of its application) to a given type of formation. The particular determination as to whether a method is "improved" would also appear to be dependent in part upon a judgment that the method proposed is at least theoretically well calculated to result in more efficient enhanced recovery than under existing methods.

Of course, a determination that a method is "new and improved" or "first of a kind" would not necessarily result in a loan or price guarantee. We would construe the operative provisions in which these phrases appear to permit if not to require a further determination that a loan or price guarantee, as the case may be, is in fact reasonably necessary to stimulate the undertaking of the project or projects in question (and, particularly in the case of loan guarantees, is consistent with priorities which would have to be adopted to allocate resources efficiently.)

7. What EOR technologies have been demonstrated on a field-wide basis?

Most of the current EOR production is credited to thermal recovery processes, mainly steam injection. Steam soak and steam drive, the most technically advanced of the EOR techniques, have been commercially applied to shallow, heavy oil reservoirs for several years. In situ combustion has been less successfully applied on a large scale with two active projects exceeding 500 acres.

Miscible gas injection projects are credited with producing approximately 25 percent of the current EOR production. The largest single EOR project is the Kelly-Snyder SACROC Unit with about 50,000 acres under CO₂ injection.

Although the project has been considered a success, the production has been less than expected and the operator is experiencing early breakthroughs of CO₂. In addition to a few other sizable CO₂ projects, there are several large hydrocarbon miscible projects. However, most of these projects were commenced prior to the escalation of oil and natural gas prices and future applications are considered marginal because of the high injectant cost.

There has been limited large-scale application of chemical EOR processes. Several polymer augmented water-floods have been successfully applied over large acreages. However, the more exotic chemical methods, surfactant-polymer and caustic floods, have been only pilot tested with one surfactant-polymer project co-sponsored by the DOE covering about 400 acres.

8. Which is the larger risk in EOR operations?

(a) that the process will or will not work? or

(b) that the process will not work in the context of a given reservoir?

Which of these risks is best addressed by S. 2999 and S. 2623?

EOR technologies are based on sound concepts and most have been demonstrated to be reliable in controlled laboratory and favorable reservoir conditions. The characteristics of individual reservoirs determine how well a given process will work or if it will work at all. Stated differently, a given EOR process may work well in some reservoirs, may work in some others but with poor performance, and may not work at all in others.

Of the two risks cited, the second, that placed in a given-reservoir-context, is the most accurate description of risk associated with EOR operations.

9. Carbon dioxide is an important chemical for some forms of tertiary recovery. What is the supply situation for CO₂?

The requirement for CO₂ for tertiary or enhanced oil is estimated to be 5,000-10,000 scf per barrel. Alternatively, a ton of CO₂ will recover 1.7 to 3.4 barrels of oil.

DOE studies to date have indicated that 30 to 50 trillion cubic feet of CO₂ can be obtained from industrial sources and an equivalent amount from the leading natural sources. This would equate to a minimum of 6 billion to a maximum of 20 billion barrels of oil. Not all of this CO₂ would be properly located or cheap enough for enhanced oil recovery. However, some of it may be recovered and recycled.

The cost of CO₂ delivered to the leading candidate reservoirs should not exceed \$1.50 per 100 scf. The best and cheapest sources should cost \$1.00 per 1,000 scf or less, delivered.

The best sources of CO₂ will be ammonia and hydrogen plant vents, certain natural gas purification plant vents, and high purity natural sources in New Mexico, Colorado, Utah, Wyoming and Mississippi. Future additions to supply would come from large high Btu coal gasification plants. A more quantitative evaluation of CO₂ supply will be available from DOE in October 1978.

10. According to the OTA report on "Enhanced Oil Recovery Potential in the U.S." the most important legal obstacle, aside from price controls, is the absence of a compulsory unitization statute in Texas and the ineffectiveness of the compulsory unitization statute in California. Would the Administration favor legislation encouraging or mandating compulsory unitization, as these two states have one half the nation's potential opportunity for enhanced recovery?

A potential institutional problem facing wide-spread application of EOR techniques is the lack of consistent State unitization laws. Most producing states provide for compulsory or forced joinder of interest owners in the unit once a specified percentage of interest owners have agreed to unitization. In the absence of such legislation, or where the necessary percentage of voluntary participation cannot be achieved, the undertaking of EOR operations can result in substantial liability for the operator due to possible damage to non-participants.

If the Administration determines that the absence of compulsory or forced unitization statutes will actually be a significant obstacle to EOR production, then the Administration should encourage the various states to enact compulsory unitization statutes. Federal legislation mandating unitization would probably be opposed by the states and may have a detrimental effect on future unitization efforts. Any Federal legislative efforts should be limited to encouraging the states to enact compulsory unitization statutes, but the benefit of such legislation would be questionable. The objective of expanding the application of forced unit rules could be best achieved by the Federal Government working with the states to develop guidelines for compulsory unitization statutes.

11. Who would be responsible for monitoring and enforcement to prevent fraud or other violations of the pricing provisions of S. 2999 or S. 2623?

The monitoring and enforcement functions with respect to the pricing provisions of S. 2623 and S. 2999 are not spelled out, and the responsibility for such activities is debatable because of the role that state agencies are expected to play in making initial determinations under these provisions and the peculiar language regarding "changed" determinations. In any further consideration of these bills, this ambiguity should be addressed and this issue clarified. However, we would take the position that the monitoring and enforcement of these provisions would be the responsibility of the DOE, which is generally responsible for administering the EPAA, in the absence of a clear delegation of these functions to another agency or agencies. Thus, we would read these provisions as permitting DOE to "change" a prior determination, even if DOE did not make the original determination, if it concluded that the producer was guilty of fraud or a lack of due diligence. We would construe this power to be exercisable retroactively, where appropriate, as well as prospectively. We believe that the interests of the integrity of and uniformity of treatment under Federal price controls would generally support this position.

However, we should note that enforcement of these provisions would be rendered difficult, particularly with respect to grounds of "fraud," inasmuch as there is no express requirement that state agencies specify the representations upon which they may be relying in making their determinations. Thus, subsequent enforcement could still depend in large measure upon the potentially differing post hoc views of particular agencies or administrators concerning the fact of reliance upon and the materiality of any given representation or set of representations. In view of these considerations, the DOE may find that it is necessary and appropriate to delegate direct enforcement functions to the states under section 5 of the EPAA.

However, we should observe that the interests of uniformity of treatment could be frustrated in the first instance by having the states make the original determinations, utilizing potentially different standards. While there is no question that a Federal tertiary recovery incentive program would benefit as a result of existing state agency expertise, even a limited Federal review of their original determinations should serve to provide better assurance that producers are being treated uniformly under the Federal program.

12. What criteria would the Secretary use to determine that "the environmental impacts directly resulting from the proposed operation have been fully evaluated by the borrower" (proposed section 22(a)(6) of Public Law 93-577 in S. 2999)?

As in the case of defining the phrases "new and improved" and "first of a kind" (see answer to question 6), the criteria for determining whether a borrower has fully evaluated the environmental impacts directly resulting from the proposed operation are likely to evolve as a result of case-by-case determinations and/or the adoption of regulatory standards in a rulemaking proceeding.

Preliminarily, with respect to the proposed legislative provision in question, we believe that a rule of reason should be applied, in which the borrower would be required to provide pertinent information concerning process characteristics, and to assess the environmental impacts of the process, to the extent that the borrower has or can reasonably be expected to obtain the necessary information. The DOE would utilize this information and the producer's assessment, as well as any other relevant information, in conducting its review.

13. What evidence indicates that uncertainty that loans will be repaid (rather than doubt about the size of return on investment) is causing a shortage of capital for investment to prove tertiary recovery techniques?

We are attempting to determine precise extent to which inaccessibility of capital limits small firms' ability to participate in EOR commercialization. At present, we do not have the data necessary to quantify this problem. However, discussions with representatives of financial institutions have led us to the preliminary conclusion that some small oil firms may have difficulty obtaining investment capital for EOR projects which may otherwise be economic to undertake. Before approving a loan, a financial institution must be assured that a company has sufficient assets to repay the debt in the event the project fails. A financial institution will accept proved and, in some cases, probable reserves as assets to secure a loan. The oil that may be recovered by an EOR project is not generally placed in the proved or probable category because the performance of most EOR processes is considered to be too uncertain. The financial institution will require, therefore, that a company use other assets to secure a loan.

For some very small firms, the investment required for an EOR project exceeds the company's total assets and financial institutions will not agree to loan the capital necessary to initiate the project. In other cases, a significant portion of the firm's total assets may have to be pledged to secure the loan. In view of this risk, the firm may view the terms of the loan as unacceptable and decide to not initiate the EOR project.

14. What amount of additional revenues will accrue to oil producers as a result of the amendment proposed by Senator Bartlett at the July 17 hearing?

The amendment introduced by Senator Bartlett would include waterflooding and would probably release 80 to 90 percent of the presently controlled crude oil production. However, we would not expect much more production than would occur with S. 2623. Accordingly, the gross operator revenues could be projected to be about 70 to 80 percent larger than those projected for S. 2623 in response to question 3.

Senator HASKELL. Our next witness is Mr. Vello Kuuskraa, vice president of Lewin & Associates, Inc., Washington, D.C.

STATEMENT OF VELLO A. KUUSKRAA, VICE PRESIDENT, LEWIN & ASSOCIATES, INC., WASHINGTON, D.C.

Mr. KUUSKRAA. I am Vello Kuuskraa, vice president of Lewin & Associates, and I am pleased to appear before your committee to testify on the subject of enhanced oil recovery. I will present a condensed version of my testimony at this time.

Despite the temporary increase in domestic oil production due to the arrival of North Slope oil, domestic reserves continue to decline. Without improved recovery and major new finds, domestic oil production could fall to 5 million barrels per day or less by 1990, far short of the 16 million barrels per day we now consume.

In spite of the contribution of thermal recovery in California, the EOR potential remains unproven and the bulk of the 300 billion barrels of oil left in the ground after primary/secondary recovery will remain inaccessible. However, as oil prices rise and the technology improves, EOR could begin to make a substantial contribution, estimated by various studies at 1 million to 3 million barrels per day by 1990.

The problem is that developing a viable EOR capacity will require considerable lead times. If we continue as now we may find that in the mid- to late 1980's the Nation has an underdeveloped technology with which to respond to higher oil prices. Major delays could be encountered and substantial production irrevocably lost.

I will now directly respond to the four questions you have posed.

Question 1. The potential of enhanced oil recovery. Currently, enhanced oil recovery provides about 260,000 barrels per day. Including steam soak would raise the current contribution of EOR to about 400,000 barrels a day, or about 5 percent of domestic oil production. The future potential of EOR has been addressed by several studies, and I have participated in several of these.

The three major studies—the NPC, OTA, and the DOE studies—come to surprisingly close conclusions. For example, under first generation technology and current world oil prices, the three studies anticipate ultimate recovery from EOR of 11 billion to 13 billion barrels and a 1990 production rate close to 1 million barrels per day. However, even 1 million barrels per day would reduce imports by only 10 to 15 percent. Thus, the important question—and I hope the one that you are addressing today—is how, if at all, can we improve on this situation?

The three key variables are, of course, economic incentives, the level of technology, and any constraints and barriers that might exist. I will address each in turn.

The threshold price for enhanced oil recovery has been studied by various groups. It is placed somewhere close to \$10 to nearly \$20

a barrel depending on the reservoirs and the particular technology that is applied. However, the current range of application of the technology is limited and the price supply curve is relatively inelastic.

We are looking at a situation where under current EOR technology, the supply curve is relatively inelastic. The hope is that through economic incentives and research and development an advanced technology could be brought about and additional oil be provided at a lower cost. In economic terms this is labeled a fundamental shift in the price-supply curve labeled as base and advanced technology curves. Now additional oil can be recovered from the reservoirs and more difficult reservoirs undertaken. Also, since the price supply curve is elastic, economic incentives have a larger payoff.

Two of the studies, by DOE and OTA, examined this advanced technology case. They found that ultimate recovery at world oil prices can reach the 29 to 30 billion barrels that we have talked about this morning—equal to current proved reserves. Also, the 1990 production rates from EOR could be 2 to 3 million barrels per day.

Even now current EOR technology and the pace of its advancement are constrained by major barriers. The most serious of these is the market/environmental/entitlement problem in California. Here the pace of thermal EOR application is constrained by: first the lack of heavy oil refining capacity, particularly with the influx of North Slope oil; second, by the lack of transportation for moving oil and the products from the west coast; and, third, the entitlements program that encourages imports over domestic oil production.

Innovative solutions, such as topping plants, combined with cogeneration and the use of solar power for low-process heat, should be considered as alternatives for addressing these problems.

Senator, we have provided a summary of this appraisal which will appear in an upcoming issue of the *Journal of Petroleum Technology* and have provided this as an attachment to the testimony.

Question 2. The need for financial incentives.

The distinction between first time and sustained EOR production as set forth in question 2 is highly appropriate. First time demonstrations could be viewed as insuring standby capacity and as alternatives to coal, shale liquids, or the strategic petroleum reserves. Thus, one might provide an incentive price up to the alternative supply levels. For this, sufficient numbers of projects would need to be undertaken to be representative of the very broad range of domestic oil resources and EOR technologies.

We have examined this and found that there are at least 20 intersections of oil resource and technology that you would have to consider, with each intersection requiring one to several projects. Given limited resources, it would be most beneficial to focus a program on those intersections that give the biggest payoff.

After the first time demonstrations, EOR will need to compete in the traditional energy marketplace. In the near term this means EOR must be competitive with imported oil. However, from a net public outlays posture it may be justified to pay a \$2 to \$5 per barrel premium for domestic oil over that paid for foreign oil. This is because the domestic oil price includes transfer payments, such as severance taxes, State and Federal income taxes, and royalties on Federal lands that, in a sense, flow back to the public. With these transfer payments a domestic oil price of \$18 per barrel really has a net cost to the public in a range to \$13 to \$16 per barrel.

In the long run the net cost to the public of EOR oil should not exceed world oil or substitute energy price.

Question 3. The relative merits of various financial incentives.

Item A, deregulation of incremental oil. This should be the minimum level of incentive as it provides domestic oil production at a net cost to the public that is less than the cost of imported oil.

Item B, deregulation of all oil produced in association with an EOR project. I have assumed that the incentive applies first to the sections of reservoirs under EOR and then would be applied to the remainder of reservoirs as the EOR project expands. This is how I now understand the legislation is proposed. The benefits of this proposal are: (a) it would provide an immediate cash flow; and (b) it would accelerate the application of EOR.

The drawbacks are that it could provide little incentive to nearly depleted reservoirs needing EOR to remain productive and it might encourage a use of low efficiency recovery techniques.

A preliminary analysis shows—and I would like to stress the word preliminary because it is a very difficult question to answer precisely—that under current EOR technology the incentive program as proposed would cost between \$2 and \$12 billion gross—after taxes \$1 to \$7 billion—and add approximately 1 billion barrels of oil to domestic supply. Under advanced technology, of course, the incentive has a higher payoff and we estimate it could add from 2 to 3 billion barrels of recovery.

Item C, price guarantees for first-of-a-kind full-scale commercial operations. The major concern is such an undertaking could require massive amounts of public moneys. The current SACROC project, assuming it will produce 200 million barrels of oil under a \$10 subsidy—the difference between \$15 and \$25 as proposed—would cost \$2 billion.

Item D, the composite price issue. Any incentive that is provided should be placed outside the calculation of the composite price; otherwise it merely involves the transfer of moneys from one pocket to another.

Item E, other incentives and policies. There is only one that I would like to discuss. Given the current tax laws it is important that the injection materials be expensed. Requiring that they be capitalized delays the cash flow, would add \$3 to \$5 per barrel, and reduce the economic potential.

Question 4. The need for loan guarantees. Given the stated purpose for this proposal, one should limit the loan guarantee program to correcting imperfections in the capital market and grant these guarantees to technologies requiring an oil price between the current and the future world oil prices. The program does have some drawbacks but they can be corrected by placing limits on the size of projects and a cap on total financial exposure and requiring a proportional share of investment capital and project defaults.

In summary, the largest benefits would accrue from financial incentives that build standby capacity from a security perspective and encourage improved oil recovery technology from a cost-benefit perspective.

I am pleased at the opportunity of discussing the merits of incentive policies that achieve these objectives. Thank you.

[The prepared statement of Mr. Kuuskraa follows:]

BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES
DIRECT TESTIMONY OF VELLO A. KUUSKRAA
JULY 17, 1978

I am pleased to appear before the Senate Committee on Energy and Natural Resources and testify on the subject of Tertiary Oil Recovery.

I am Vello A. Kuuskraa, Partner and Vice President of Lewin and Associates, Inc. of Washington, D.C. During the past several years we have completed numerous analyses and studies of the economics and the potential of tertiary or enhanced oil recovery. I would like to draw on this past information in responding to the questions you have posed.

BACKGROUND

Current Status

Despite the temporary increase in domestic oil production due to the arrival of North Slope oil, domestic reserves continue to decline:

- Year end proved reserves of 29.5 billion barrels are at their lowest level since 1953.
- New Field discoveries remain low -- at only 100 to 200 million barrels of new finds per year.
- The bulk of the additions to proved reserves have been due to secondary recovery (water-flooding) and extension drilling in already discovered fields.

- Without improved recovery from existing fields (through enhanced oil recovery) and major new finds (through exploration), domestic oil production could fall to 5 million barrels per day in 1990, far short of the 16 million barrels per day we now consume. (Exhibit 1)

EOR Potential

In spite of the contribution of thermal recovery in California, the bulk of the EOR potential remains unproven due to an embryonic and uncertain nature of the technology and its high costs.

Thus, the great bulk of the 300 billion barrels of oil left in domestic reservoirs after primary/secondary recovery remains inaccessible in light of current technology and oil prices.

However, as oil prices rise (in real terms) and the recovery technology improves, EOR could begin to make a substantial contribution to domestic oil recovery. Various studies (FEA, ERDA, NPC, OTA) have placed this potential at 1 to 3 million barrels per day by 1990 depending on economics and the status of the technology.

The Key Barriers

Applying and advancing the state of the art of enhanced oil recovery involves considerable lead times. It takes from 5 to 15 years to develop an EOR process (through research and demonstration) and to

1 initiate commercial scale field application. Thus, it may be that in the
2 mid to late 1980's, the nation has an undeveloped or underdeveloped EOR
3 technology with which to respond to high oil prices. Major delays could
4 be encountered and substantial oil production delayed or irrevocably lost
5 during the critical 1985-1990 period.

6 Public Policy Alternatives

7 While numerous policy options have been considered, three
8 stand out:

- 9 • Encouraging improvements in the EOR tech-
10 nology through research and development;
- 11 • Providing economic incentives to stimulate
12 increased EOR production and development; and
- 13 • Using loan guarantees to support demonstrations
14 of the best available EOR technology to ensure
15 that all segments of the industry (particularly
16 the independent producers) would have access
17 to EOR technology when oil prices stimulate its
18 widespread application.

19 I am pleased to respond to your four questions that address
20 the need for encouraging additional production through enhanced oil
21 recovery.

Question 1: WHAT POTENTIAL DO TERTIARY OIL RECOVERY TECHNIQUES OFFER
FOR INCREASING OUR SUPPLIES OF OIL?

Currently, enhanced (tertiary) oil recovery (EOR) provides about 265,000 barrels per day, up from about 235,000 barrels per day in 1975. This production is distributed, as follows, by the main EOR techniques:

<u>EOR Techniques</u>	<u>1977 Production Rate (B/D)</u>
• Steam Drive	140,000
• In Situ Combustion	10,000
• CO ₂ , Hydrocarbon Miscible and Inert Gas	110,000
• Surfactant, Polymer and Other Chemical	<u>5,000</u>
	265,000

(Steam soak would add about 120,000 B/D and would raise the total to nearly 400,000 B/D, or 5% of domestic oil production.)

With this background and the critical need to augment domestic oil production, three questions were posed:

- How much can EOR supplement domestic oil production?
- Will the cost be competitive with alternative sources and affordable to the consumer?

- What types of initiatives could accelerate and increase the potential as well as lower the cost to the public?

Several recent studies have addressed these questions, including studies by the Department of Energy (DOE), the Office of Technology Assessment (OTA/U.S. Congress), and the National Petroleum Council (NPC). I was closely involved with the DOE and OTA studies and shared our Firm's oil resource data with the NPC study.

After making appropriate adjustments for certain assumptions (discussed below), the three studies come to surprisingly close conclusions. For example:

- Under first generation oil recovery technology and current world oil prices the three studies anticipate ultimate recovery of 11 to 13 billion barrels and a 1990 production rate of 0.6 to 1.1 million barrels per day.
- Specifically, the three studies reached the following estimates of potential:

	<u>Ultimate Recovery</u> <u>(Billion Barrels)</u>	<u>1990 Production Rate</u> <u>(Million Barrels/Day)</u>
DOE (Constrained Base Case)	13	0.6
OTA (Low Process Performance)	11	0.7
NPC (Averaging Case)	11	1.1

These quantities of oil are sorely needed and will appreciably assist the nation's balance of trade, but even a million barrels per day will reduce imports by only 10 to 15 percent. Thus, the real and important question and the one being addressed is:

HOW, IF AT ALL, CAN WE IMPROVE ON THIS SITUATION?

The three key variables are:

1. Oil price and other economic incentives;
2. The level of EOR technology; and
3. Constraints and barriers to EOR production

I will discuss each in turn.

1. Oil Price/Economic Incentives

One of the important variables is the price and economic incentives set for tertiary oil. The threshold price, the price where the most favorable reservoirs begin to be economic under tertiary recovery appears to range from \$5.00 to \$10.00 per barrel for the thermal techniques,

1 \$10.00 to \$15.00 for CO₂ miscible, and \$15.00 to \$20.00 for surfactant/
2 polymer flooding. After this, a higher oil price is required to apply
3 the EOR process to successively less favorable reservoirs.

4 However, the range of application of current EOR technology is
5 limited. The process is relatively inefficient, thus the price-supply
6 curve is inelastic (as shown on Exhibit 2) and economic incentives
7 strategy, on its now, provides only limited additional oil.

8 2. Level of EOR Technology

9 Should the economic incentives or other techniques, such as
10 direct public/private investment in R&D, lead to an advanced level of
11 EOR technology, the potential increases substantially and additional
12 oil is provided at a lower cost. In economic terms, this is labeled a
13 fundamental shift in the price-supply curve (as depicted on Exhibit 2).

14 Now, additional oil can be recovered from the favorable
15 reservoirs, and more difficult reservoirs can be undertaken by EOR.
16 Also, the price-supply curve becomes more elastic and economic incentives
17 have a larger payoff.

18 Two of the studies, by DOE and OTA, explicitly examined the
19 improved technology case, and found:

- 20 • Ultimate recovery at world oil prices can
21 reach 29 to 30 billion barrels.

- The 1990 production rate at this price level could be from 2 to 3 million barrels per day.

3. Overcoming Constraints and Barriers

Even now, the application of current technology and the pace of advancement in EOR technology are constrained by major barriers. The two most serious of these are:

a. The market/environmental/entitlements

problem in California. The pace of thermal oil recovery application is severely constrained by:

- the lack of heavy oil refining capacity in California (particularly with the influx of Alaska North Slope oil)
- the oversupply of middle distillate and the lack of economical transportation for moving oil and product from the West Coast market
- the entitlements program that encourages imports over domestic heavy oil production (now being addressed by DOE/ERA).

1 Innovative solutions such as topping plants, combined with
2 co-generation, the use of solar power for low-process heat and heavy oil
3 gasification should be considered as alternative for addressing these
4 problems.

- 5 b. Obtaining adequate supplies of injection
6 materials, particularly natural or low-
7 cost manufactured CO₂. Identifying CO₂
8 sources would help in shortening the lead
9 times of pipeline construction.

10 We have condensed our appraisal of the EOR potential for
11 the September issue of the Journal of Petroleum Technology. The
12 appraisal, now two years old, remains essentially unchanged except
13 that:

- 14 • steam drive is finding broader application,
15 particularly in deeper and in light oil
16 reservoirs;
17 • carbon-dioxide flooding, as initially con-
18 ceived and as being applied in the massive
19 SACROC project, is less efficient than
20 hoped -- a modified version of the process
21 appears required;

- surfactant/polymer flooding is more expensive than originally anticipated.

A copy of our article is provided as an attachment (Attachment A).

Question 2: NEED FOR FINANCIAL INCENTIVES?

The distinction between "first time" and sustained EOR production, as set forth in Question 2, is highly appropriate.

A. First Time Demonstrations

First time demonstrations could be viewed as ensuring standby capacity and could be evaluated as an alternative to coal/shale liquification and to the strategic petroleum reserve. Thus, one might provide an incentive price up to the stand-by supply level for "first time" demonstrations.

Selecting these projects poses two concerns, as discussed below:

- Eligible Projects -- Technological View

The concern would be that sufficient number of projects would be undertaken to be representative of the range of domestic oil resources and the most appropriate EOR technology(s).

Exhibit 3 provides a display of the domestic oil resource targets and the EOR technology(s) most appropriate for exploiting that resource target. This shows that 20 intersections of resource and

1 technology would result. Assuming one project each for the novel
2 technology/resource intersections and a minimum of two projects each
3 for the remaining technology/resource intersections, a minimum of 36
4 projects would be required.

5 Further discussion of the nature of these technology/resource
6 target intersections is provided in Appendix B:

7 • Eligible Projects -- A Priority View

8 Each EOR technology resource target intersection has
9 its own marginal price/supply curve. Given limited resources it would
10 be most beneficial to focus the program on those intersections providing
11 the greatest payoff. For example, the application of Advanced Steam
12 Drive technology to Shallow-Heavy Oil could provide 3 billion barrels
13 of additional oil, while applying a Novel Recovery Technique to Low-
14 Recovery/Fractured Reservoirs, might provide only 0.5 billion barrels of
15 additional oil.

16 Given limited funds, advanced technology in Shallow-Heavy Oil
17 resource target could be preferred over the Low-Recovery/Fractured
18 Reservoir target.

19 Considerable analysis, not yet available, is required to assess
20 the economic potential of each resource target in light of the most
21 applicable EOR technology and the level of financial incentives that
22 would be adequate.

B. Sustained EOR Production

After the "first time" demonstration, EOR will need to compete in the traditional energy market place. In the near-term, this means it must be competitive with imported oil; in the longer-term (or at limited import levels) it might need to compete with liquids from shale, or energy substitution of gas and coal.

Thus, the world oil price and energy substitution provide the boundaries for efficient financial incentives.

However, from a net public outlays posture, it may be justified to pay a \$2.00 to \$5.00 per barrel premium on domestic oil over that paid for foreign oil. This is because the domestic oil price contains transfer payments (e.g., severance taxes, state and Federal income taxes and royalties on Federal lands) that flow back to the public. The value of these transfer payments at an oil price of \$18.00 per barrel is shown below:

• Gross Oil Price	-	\$18.00
Less: Severance Tax @ 6%		\$1.00
Federal and state income		
tax @ 40% of profits		1.00
Royalties		<u>0-3.00</u>
Total Transfer Payments		\$2.00 to \$5.00
• Net Cost to Public	-	\$13.00-\$16.00

1 In the long-term, for efficient sustained EOR production,
2 the Net Cost to Public for EOR oil should not exceed the world oil or
3 substitute energy price.

4 Question 3: RELATIVE MERITS OF VARIOUS FINANCIAL INCENTIVES?

5 A. Deregulation of Incremental Oil Produced by EOR

6 This should be the minimum level of incentive in that it
7 provides domestic oil production at a Net Cost to Public that is less
8 than for imported oil. (The benefits of this incentive have been
9 discussed under Question 1.)

10 B. Deregulation of All Oil Produced in Association With an EOR Project

11 It is assumed that the incentive applies first to the section
12 of the reservoir under EOR and then would be applied to the entire
13 reservoir as the EOR project expands.

14 The benefits of this proposal are that:

- 15 -- it would provide an immediate cash flow
16 -- it would accelerate the application of EOR.

17 The drawbacks are that:

- 18 -- it would encourage EOR application to
19 reservoirs with large quantities of
20 releasable oil and less to nearly depleted
21 reservoirs needing EOR to remain productive

1 -- it might encourage the use of low-
2 efficiency EOR techniques.

3 While detailed analysis would be required to fully answer this
4 question, a preliminary theoretical analysis shows (provided as Attach-
5 ment C):

6 -- under current technology, the
7 incentive program could cost \$2
8 to \$12 billion gross (\$1 to \$7
9 billion net after taxes) and add
10 approximately 1 billion barrels
11 of EOR recovery

12 -- under advanced technology, the in-
13 centive program could add 2 to 3
14 billion barrels of additional EOR
15 recovery (further analysis is required
16 to ascertain the costs of the program).

17 C. Price Guarantees for "First of a Kind" Full-Scale Commercial Operations

18 This issue has been addressed in the response to Question 2. The
19 major drawback would be that such an undertaking could require massive
20 amounts of public monies. For example, assuming that the SACROC CO₂ project
21 had been given a \$25.00/B price guarantee, at a world price of \$15.00/B,
22 the public cost for the 200 million additional barrels would be \$2 billion.

1 D. The "Composite Price" Issue

2 Any incentive that is provided, even the minimum deregulation
3 of incremental EOR oil, should be placed outside the calculation of the
4 "composite price." Otherwise, it merely involves the transfer of monies
5 from "one pocket to another pocket." Moreover, the mere transfer within
6 the "composite price" to favor tertiary recovery at the expense of con-
7 ventional oil may be counter productive in that it could decrease the
8 quantity of conventional oil production. (The DOE/ERA "composite price"
9 amendments have been proposed with this in mind.)

10 E. Other Incentives and Policies

11 Given the current U.S. tax laws, it is important for EOR
12 economics that the injection materials be allowed to be expensed. Re-
13 quiring that these materials be capitalized would further delay the cash
14 flow, add from \$3 to \$5 per barrel to the required selling price of the
15 oil and reduce the economic potential of surfactant/polymer and CO₂
16 miscible flooding.

17 Question 4: NEED FOR LOAN GUARANTEES FOR SMALL PRODUCERS FOR "FIRST OF
18 A KIND" EOR DEMONSTRATION?

19 It is assumed the purpose of these loan guarantees would be:

- 20 • to ensure capital availability to the in-
21 dependent sector of the oil production
22 industry;

- 1 • to lower the perceived risk premium, and
- 2 its associated return on capital require-
- 3 ments; and
- 4 • to ensure that efficient EOR technologies are
- 5 in place when oil prices rise sufficiently
- 6 to make these technologies economically
- 7 viable.

8 Conceptually, one would limit the loan guarantee program to
9 correcting imperfections in the capital markets and to technologies
10 requiring an oil price above current world oil prices but not more than
11 future world oil prices.

12 We can not comment on the internal cash availability of small
13 oil producers, but we can ascertain that enhanced oil recovery entails
14 considerable front-end capital and negative cash flows for periods of
15 five to over ten years per project.

16 The drawback to the use of loan guarantees could be the
17 large amounts of capital and budget exposure required for field-scale
18 demonstration, the considerable number of demonstrations (given the
19 range of EOR technologies and domestic reservoirs) and the possibility
20 of inefficient private allocation of resources.

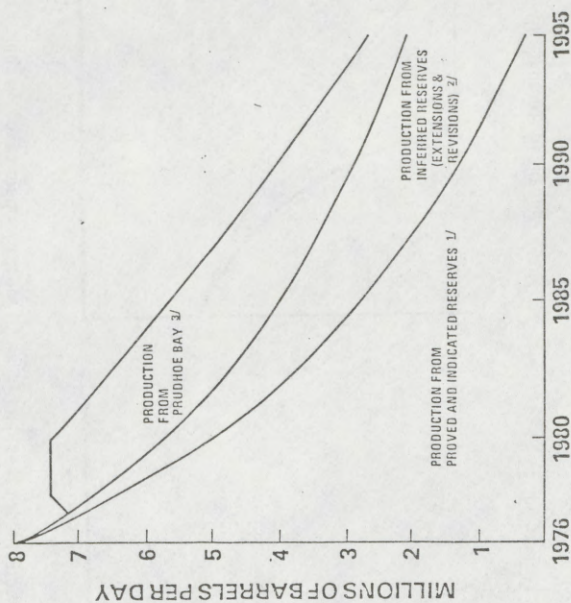
1 Placing limits on the size of projects, a cap on total
2 financial exposure, and requiring a proportional sharing of investment
3 capital and project defaults (should they occur) could mitigate these
4 concerns.

5 SUMMARY

6 In summary, the largest benefits would accrue from financial
7 incentives that build both stand-by capacity (from a security/emergency
8 perspective) and encourage improved oil recovery technology (from a
9 cost-benefit perspective). Further study is required to pick the set
10 of incentive policies that achieve these two objectives at the lowest
11 net cost to the public.

EXHIBIT -1

PROJECTED PRODUCTION BY CONVENTIONAL METHODS FROM KNOWN U.S. RESERVOIRS, 1976-1995



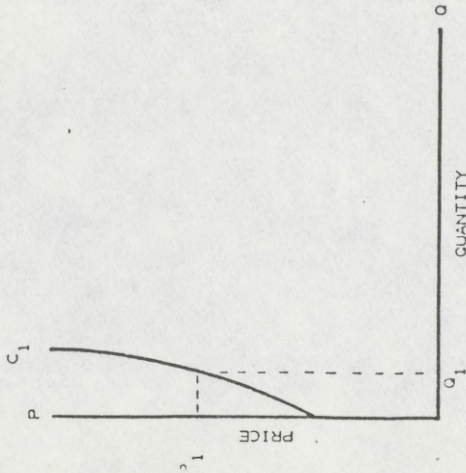
SOURCES: 1/ AMERICAN PETROLEUM INSTITUTE, *RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS, AND NATURAL GAS IN THE U.S. AND CANADA AS OF DECEMBER 30, 1976*; LEWIN & ASSOCIATES, INC., FOR FEDERAL ENERGY ADMINISTRATION, *DECLINE CURVE ANALYSIS, 1976*.

2/ U.S. GEOLOGICAL SURVEY, *CIRCULAR 725, 1975*.

3/ FEDERAL ENERGY ADMINISTRATION, *NATIONAL ENERGY OUTLOOK, 1976*.

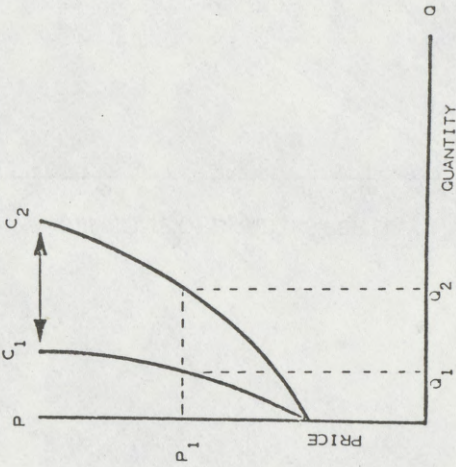
EXHIBIT 2
IMPACT OF TECHNOLOGY ON PRICE/SUPPLY

(1)
The Current Situation

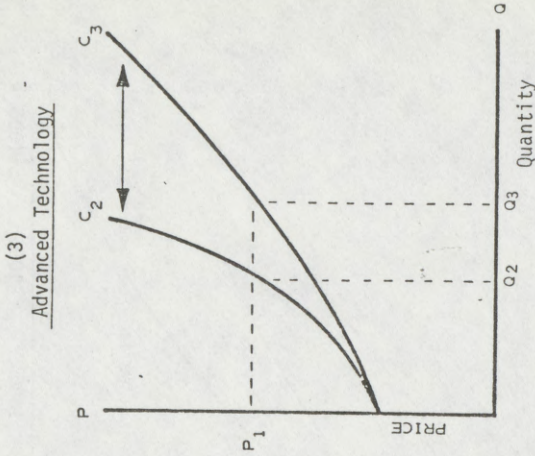


Supply response (Q_1) to price incentive (P_1) is small

(2)
Base Case Technology



In response to price incentives and the need for oil, industry advances the technology to Base Case, providing a larger quantity (Q_2) of supply at price (P_1)



Industry undertakes higher risk, second generation technology advancement jointly with DOE to further shift the supply curve providing more supply (Q_3) at the same or lower cost.

EXHIBIT 3
HIGH PRIORITY RESOURCE TARGETS FOR ENHANCED OIL RECOVERY

DOMESTIC OIL RESOURCE TARGETS	EOR TECHNOLOGIES				
	Advanced Steam Drive	Improved Combustion	Improved CO ₂ Flooding	Surfactant/ Polymer	Augmented Waterflooding
1. Shallow-Heavy Oil (California)	X	X			
2. Deep-Heavy Oil	X				
3. Western and Rocky Mountain Carbonates			X		
• High SOR			X		
• Low SOR			X		
4. Other Carbonates			X		
5. Gulf Coast Sandstones					
• High Dip - Low Viscosity			X	X	
• Other			X	X	
6. California Sandstones			X		
7. Rocky Mountain and Other Sandstones			X	X	
8. Shallow Homogeneous Mid-Continent Sandstones			X	X	
9. Thin, Low-Permeability Light Oils	X				
10. Other High Saturation, Heterogeneous Reservoirs					X
11. Special Targets					
• Tar Sands					X
• Virgin Reservoirs					X
• Offshore Reservoirs					X
• Low Recovery/Fractured Reservoirs					X

ATTACHMENT ATHE POTENTIAL AND ECONOMICS OF ENHANCED OIL RECOVERY

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INTRODUCTION

Over two-thirds of the oil discovered in the United States remains unrecovered through conventional (primary and secondary) production technology. This amounts to over 300 billion barrels left in the ground, according to estimates by the American Petroleum Institute.¹ Additional recovery of even relatively modest portions of this oil could significantly reduce the nation's projected dependence on imports. Producing some portion of this remaining oil is the purpose of enhanced oil recovery -- the application of advanced technology to crude oil production.

The Federal government seeks to encourage the development and application of EOR because these techniques hold promise of accelerating domestic production in the period from the present to 1995, before non-petroleum substitutes are fully developed. Two major policy options are available for this goal -- increased economic incentives and sponsored research and development. A series of studies was undertaken by the U.S. Department of Energy^{2,3,4} to determine:

- What are the most critical barriers to widescale application of EOR? Which of these barriers could be removed through Federal programs or policies?
- How much can EOR supplement domestic petroleum production? When can this production be expected?
- What will be the cost of EOR? Will it be affordable in the near term?
- What portion of EOR's total potential will industry develop under varying economic incentives?
- What research and development achievements will stimulate industry to produce more enhanced oil and to produce it faster?
- What are the trade-offs between economic incentives and public R&D? Will one or the other option exhaust EOR opportunities or is a mix of both needed?

This paper summarizes the results of over two years of study focused on these and other questions concerning the potential of enhanced oil recovery.

DOMESTIC SUPPLY AND DEMAND OF PETROLEUM

Petroleum products provide nearly one-half of the nation's total domestic energy consumption and nearly all its transportation requirements.

Demand for these products increased at an average rate of nearly 5 percent annually from the Second World War until it peaked in 1973 at 17 MMB/D. The embargo, in conjunction with higher prices and a slowed economy, arrested this trend; consumption in 1974 and 1975 dropped to about 1972 levels.⁵ The revival of the economy and increased sales of larger automobiles augur for a return of the growth trend. Estimates for the next fifteen years predict rising demand, with an average growth of 2.7 to 4.4 percent, depending on the assumptions used.⁶ Even at the lower growth rate, demand for petroleum could reach 25 MMB/D in the early 1990s.

While demand has risen, domestic supply has not kept pace. Current production capacity is about 8 MMB/D and declining. Projected production from known fields under conventional technology, even including Prudhoe Bay and inferred reserves, will drop to about 4 MMB/D in 1990 and to 3 MMB/D by 1995 (Figure 1).

Exploration will add to domestic supply, but the size of the new reserves is in question. Estimates of undiscovered reserves have decreased steadily since 1970 and even these reduced estimates contain potentially optimistic projections for the onshore, lower forty-eight state area. Historical correlations of drilling and new finds in these mature provinces suggest that little remains to be discovered.⁷ Reserves from new discoveries in Alaska and offshore, the more promising areas, are estimated to add

38 billion barrels.⁸ However, these reserves, if discovered, will lie in environmentally hostile and fragile areas, will be very costly to produce, and may become available only after considerable delay.

Thus, production from newly discovered reserves may not add as much to production between now and 1990 as had formerly been anticipated. The 1976 National Energy Outlook projects that these sources will add, in 1990, slightly more than 3 MMB/D, under favorable oil price assumptions. Under conventional technology and optimistic exploration assumptions, then, total domestic production in 1990 may not exceed 7 MMB/D.

Rising prices and synthetic alternatives to petroleum could also increase the domestic supply of liquid hydrocarbons. Higher crude oil prices have stimulated some additional "stripper" production by prolonging the economic life of declining fields. Future gains of this sort, however, will be small relative to overall supply requirements. Synthetic alternatives to petroleum, currently under development, will become sufficiently available only in the distant future, contributing little to domestic supply by 1990.

The continuing rise in demand, the decline in conventional domestic production, and the belated development of alternatives to petroleum combine to increase the nation's dependence on imports.

Enhanced oil recovery -- the introduction of heat, miscible fluids, or chemicals into oil reservoirs to improve their recovery efficiency -- could offset a portion of this dependence. However, the amount, cost, and

timing of the EOR contribution are highly uncertain. The studies summarized here seek to reduce these uncertainties by examining the interactions of the EOR technology, industry's plans for its application, and the policies of the Federal government.

ANALYTIC APPROACH

Logic of the Analysis

The methodology used by this study follows: an engineering and micro-economic approach that emulates -- on a slightly broader scale -- the actual decision behavior of the companies that will apply enhanced oil recovery. The reservoir was the basic unit of analysis. Reservoirs that were established to be viable EOR candidates according to technical and broad economic criteria were analyzed using detailed cost and recovery models. The economic production (under a variety of assumed economic conditions) was then aggregated and extrapolated to national totals.

Following the flow of reservoirs through the analysis (Figure 2) provides an overview of the logic underlying the approach. A nationally representative sample of reservoirs were first screened for technical and then gross economic feasibility. Reservoirs for which EOR is infeasible were discarded. The remaining reservoirs, representing some degree of promise for EOR development, were grouped into EOR targets according to

the most favorable technique and common development problems. To the extent that the original sample was representative, and the screens represented the outside bounds of possible EOR advances in the next twenty years, the resulting targets represent an exhaustive set of EOR opportunities.

These targets were then partitioned into four broad categories:

- Those within current technological bounds and unaffected by non-process factors.
- Those outside current technology but within the anticipated scope of industry research and development at the current rate of development.
- Those within current or anticipated technology but which are constrained by non-process factors, such as environmental limitations, market imbalances, or shortages of critical supplies.
- Those outside current technology but that potentially could be developed through an accelerated program of research and development.

The first two categories are targets that industry is highly likely to develop during the period of interest. These were analyzed for their economic feasibility. Estimated production from those that were

found to be economic comprises the "Base Case" -- EOR applications that would take place in the absence of a public/private collaborative R&D program. Reservoirs in these categories that were found to be uneconomic under a particular price automatically became candidates for additional R&D and were placed in the fourth category below.

The third category, reservoirs where the production is restricted by various non-process constraints, consists of targets for public/private R&D programs designed to relax constraints, thereby accelerating the rate of production. The nature of these constraints is described below.

The fourth category, then, consists of reservoirs that would remain underdeveloped. These became targets for accelerated technological advances. Estimated production from these last two categories of reservoirs comprises "Production Stimulated by R&D Programs" (in Figure 2) -- the Accelerated R&D Case.

Methods of Analysis

The reservoir data base used in this study contains detailed data on the physical characteristics and production histories of 352 reservoirs in 17 states. Collectively, they account for forty-eight percent of the nation's remaining oil. Statistical tests were conducted to determine whether the reservoirs in the data file were representative of the seventeen

states (and sub-state districts). Using recovery efficiency as the basic measure and 95 percent confidence intervals, the data in the file were found to be consistent with the hypothesis of random sampling from the full API data base, strongly implying that the sample is representative. Based on this and the extensive coverage of the data base, the data file was extrapolated to totals for the 17 states. Because these seventeen states contain 94 percent of the nation's reserves, this is tantamount to a total U.S. projection.

The technological screen (Table 1) was developed through consultation with prominent EOR practitioners and in-depth reviews of nearly 200 existing EOR pilot projects. It includes steam drive (but not cyclic steam), in situ combustion, carbon dioxide miscible flooding, surfactant/polymer flooding, and polymer augmented waterflooding. Caustic flooding was not included due to lack of empirical results to date. Hydrocarbon miscible flooding was excluded because it is considered uneconomic at current natural gas prices. The boundary values incorporated into the screen express the technology limits that appear attainable during the period of interest, now to 1995, although reaching many of these limits would require substantial additional investment and effort in R&D.

The simulation models used for both the broad economic feasibility screening and the subsequent production projections were based on analyses

of the development patterns and results of current and past field efforts. The models (described in detail in references 3 and 4) simulate the phased field development, costs, and recovery for each reservoir and each technique. Actual reservoir characteristics and field development conditions were used in estimating oil recovery and costs.

Oil recoveries from reservoirs that were economic under given price conditions were extrapolated (using remaining oil-in-place as the extrapolation index) to state or sub-state district totals and aggregated to national projections.

The economic component of the model was a discounted cash flow formulation that assumed the constant 1976 relationship of costs to prices. Required discount rates reflected the degree of risk inherent in the project -- 8% for low risk and up to 20% for high risk. Because real prices were used, the rate of inflation would be additive to these discount rates, e.g., at 7% inflation, the low-risk rate of return in current dollar terms would be 15% at an inflation rate of 8%. The timing of initiation of field projects was a function of profitability, with the most attractive reservoirs being developed first, and of the time lag required for the initial R&D. All costs were adjusted to July 1976 levels.

Structured interviews were held with research and production managers of nine integrated and five independent operators to ascertain industry's near-term plans for EOR development and application. This

provided an overview of the nature and direction of industry's R&D and the criteria industry will apply when considering investments in EOR. This information, combined with the status appraisals, permitted assignment of reservoir targets into four categories -- the two that industry is anticipated to develop (the Base Case) and the two that require accelerated public/private R&D. Research objectives, methods, costs, and expectation of success were specified through consultation with industry research managers and government officials.

To examine the sensitivity of the Base Case to publicly supported R&D, the cost and recovery models were modified to incorporate the R&D achievements stipulated in the program objectives.

The aggregate of production from these technically and economically feasible reservoirs was multiplied by an "expectation of success" to yield results in terms of expected production. The expectation of success is the proportion of the potential R&D target that could be realized through an R&D program. These were calculated as the means of the probability distribution defined by estimates of the 0.05, 0.5, and 0.95 probability points.

Analysis of the sensitivity of the Base Case to changes in economic conditions existed of examining two tax conditions and four price levels in selected combinations. The tax cases varied the investment tax credit from 10% to 13% and various required capitalization or expensing of EOR injection

fluids. The prices analyzed were "lower-tier" (\$5.20/B), "upper-tier" (\$11.62/B), landed world price (\$13.00/B), and the estimated price for synthetic substitutes for petroleum (set at \$20.00/B). All prices were maintained in real terms and were adjusted for the current gravity differential. The "upper-tier" price/current tax combination was defined as "Standard Economics" and provides the base for analyzing alternative economic conditions.

THE BASE CASE

Summary of the Current Status of the Technology

Enhanced oil recovery is far from a proven technology. Years of testing have yielded only one process -- steam drive -- that approaches conventional application. Even with the experience of at least 187 projects and with over 130 thousand acres under current development, enhanced oil recovery has advanced slowly. The status of the technology as of 1976 can be summarized as follows:

- EOR currently produces over 240 MB/D (including hydrocarbon miscible but not cyclic steam projects).
- Steam drive accounts for the largest portion of this production, 110 MB/D; hydrocarbon miscible contributes 70 MB/D; carbon dioxide miscible provides 40 MB/D; in situ combustion, surfactant/polymer, polymer and caustic augmented waterflooding together provide the remaining 20 MB/D.

- Two important changes are underway that could significantly influence the amounts of enhanced oil being produced:
 - Several major operators indicate plans for converting their existing steam soak projects to steam drive, and this alone could increase production by an additional 200 MB/D, should West Coast environmental problems be overcome and a market be established for heavy oil.
 - Due to the recent increases in natural gas prices, few major new efforts will rely on hydrocarbon miscible flooding. Several of the hydrocarbon miscible projects are converting (or already have converted) to other injection fluids, such as flue gas or carbon dioxide.
- Substantial uncertainty besets the application of EOR:
 - Unpredictable process performance in the reservoirs.
 - Unreliable data on reservoir characteristics, especially oil saturations and distributions.
 - Uncertain costs of application.
 - Uncertain prices and tax treatment for crude oil produced by EOR.
- The process-related uncertainties vary substantially by technique:

- Steam drive is approaching conventional application in the shallow, high saturation reservoirs in which it has typically been applied.
- In situ combustion, while having experienced substantial testing, remains unproven and difficult to predict.
- Carbon dioxide miscible flooding projects have not yet produced sufficient data to evaluate this technique's true potential. Some limits on its applicability have begun to appear, especially when this technique follows waterflooding.
- Chemical processes have not fared well in the transition from laboratory to field pilot operation. Surfactant, polymer, and caustic applications are the least predictable and the farthest from conventional application.
- Major difficulties with many techniques have been encountered in extrapolating from laboratory results to field tests. Demonstrations of effectiveness in the lab have not been replicated in the field. This argues that substantial basic research, both in the lab and in the field, is required for the less proven techniques.

Industry's Directions in EOR

Given the current uncertain status of the technology, industry plans to proceed cautiously, choosing the research, development, and field applications that provide the most assured return.

- Ongoing and planned R&D by industry is concentrated on improving the effectiveness and predictability of EOR techniques for the most promising reservoirs under each operator's control. Industry's future research and development will closely resemble the current technical pilots in the field.
- The level of expenditure on R&D in enhanced recovery will be substantial, but will remain limited by the present technological and economic uncertainties, the potentially long lead times before commercial application, and the difficulties in protecting patents.
- Industry's field expansion plans are limited to the most favorable reservoirs. Planned developments will increase production slowly -- after industry's research has made the techniques more predictable, hence less risky.
- Oil producers' clearly stated decision rule on field applications is that they will apply EOR techniques

when such projects compete favorably with other investment opportunities in terms of expected net present value. The current appraisal of EOR's technological risks and uncertain prices lead operators generally to choose other, more certain or higher payoff opportunities.

The Base Case Under Standard Economics Conditions

Taking into account the status of the technology and industry's apparent directions, an estimate was made of the Base Case -- the pace of technological development and the projected additions to recovery without the influence of public/private collaborative R&D programs. The reservoir targets considered within current technology and industry's near-term R&D advances include:

- Steam drive in heavy oil reservoirs shallower than 2,500 feet.
- In situ combustion in heavy oil reservoirs with high residual oil saturations.
- Carbon dioxide miscible flooding in high oil saturation carbonate reservoirs in the Southwest and Rocky Mountain areas.
- Carbon dioxide miscible flooding in reservoirs where pilot testing is ongoing.

- Surfactant/polymer waterflooding in the shallow, homogeneous reservoirs of the midcontinent.
- Polymer flooding in high saturation, light oil reservoirs.

At upper tier prices and current taxes (The Standard Economics Case), it is estimated that this grouping of reservoirs will ultimately produce approximately 11.9 billion barrels through enhanced oil recovery.

- Over half of this, 6.2 billion barrels, will be by steam drive.
- Carbon dioxide miscible will contribute almost forty percent, 4.7 billion barrels.
- Small additional amounts will be produced using in situ combustion (0.9 billion barrels) and polymer augmented waterflooding (0.1 billion barrels).

Under these economic conditions, no production from the surfactant process is expected. The majority of ongoing projects using this process are uneconomic, a fact recently confirmed by several operators using surfactants. Note that these production estimates are incremental production over recovery through conventional means. Thus, this 11.9 billion barrels represents anticipated additions to domestic oil reserves.

Figure 3 shows the production rates for the Base Case under Standard Economics conditions. By 1985 the production rate will be about 600 thousand barrels per day. The production rate stays at this level

through 1990, then declines slightly to 550 barrels per day. The "flattening" of the curve reflects the effects of non-process constraints, especially environmental restrictions and potential market imbalances for heavy oil in California, reducing steam drive production, and the anticipated shortage of naturally occurring carbon dioxide for miscible flooding. Steam drive is the process that is most severely constrained by non-process factors. Although it has the greatest ultimate recovery of the five processes, the constraints spread this production over an extended period of time, limiting the rate of its contribution between the present and 1995 to substantially less than the contribution from carbon dioxide. Together, these constraints hold the rate of production to less than half the rate it would be if there were no constraints during the period 1985-1995. Between the present and 1995, these constraints will hold cumulative EOR production to about one-third of its ultimate recovery -- 3.7 billion barrels.

SENSITIVITY OF THE BASE CASE TO ECONOMIC INCENTIVES

Base Case production was found to be essentially insensitive to a three percent change (10% to 13%) in the investment tax credit. This was found to be true at both upper-tier and world price levels. (The analysis was not done at the other price levels.)

Base Case production was, however, quite sensitive to changes in tax provisions that would require capitalizing, rather than expensing of injection chemicals. This requirement -- currently under consideration by the Internal Revenue Service -- would make some now marginally attractive reservoirs uneconomic. At upper-tier price, projected production by carbon dioxide would be reduced by 13% and production by polymer augmented waterflooding would drop by 10%. Steam drive and combustion would be unaffected because the steam and air injected would still be expensed. (The surfactant process was uneconomic with current taxes at upper-tier price, so it is unaffected. Had this technique been economic, its production also would have been reduced.)

Prices

Under present regulations, the existing price for EOR crude is a mix of lower-tier and upper-tier prices, depending on the reservoir's situation. And, although Congress has passed legislation enabling the Administration to provide special price incentives for EOR production, the rule-making on these incentives is not yet complete.*

* At this time, efforts are underway within DOE to provide incentives for EOR production; however, the specific nature of these incentives is not available in the public domain.

Within the range of prices included in the analysis, \$5.20/B to \$20.00/B, Base Case ultimate recovery was found to be highly sensitive to price. Ultimate recovery varies from 3.9 billion barrels at lower-tier price to 17.0 billion barrels at alternative fuels price (Figure 4). Movement from the lower-tier price to upper-tier price adds 8 billion barrels, to total 11.9 billion barrels. About 10% more production is added by moving from upper-tier to landed world price.

Steam drive provides the bulk of the additional oil under all price and tax cases. Carbon dioxide flooding does not provide significant amounts at lower-tier prices, but it begins to make a contribution at upper-tier price. Surfactant makes no contribution at the two lower prices, begins to be developed at \$13.00/B, and makes a major contribution at \$20.00/B.

The rate of production was also found to be sensitive to changes in price (Figure 5). At lower-tier prices (not shown) the production curve peaks in about 1985 at 270 MB/D and declines as the relatively few economic reservoirs become depleted. (The lower-tier case is not described further because of its relatively insignificant contribution.) At \$11.62 and \$13.00 the production curve rises to about 600 MB/D and remains there after 1985. The curve for the alternative fuel price rises consistently, though not dramatically. The flattening of the curve for the middle two prices and the relatively slow rise of the highest oil price curve are due to the

various non-process constraints. California environmental regulations and marketing problems due to the "entitlements" program and the arrival of Alaskan crude hold steam drive production to 110 MB/D. Limited supplies of naturally occurring carbon dioxide constrain carbon dioxide production to 400 MB/D. Thus, the full accelerating effect of price incentives is muted by the constraints that apply even within the bounds of current and near-term technology.

SENSITIVITY OF THE BASE CASE TO ACCELERATED R&D

The Base Case estimates assumed a modest pace of technological development and application, including continuation to fulfillment of the R&D currently underway in industry and in present industry-government collaborations. Because numerous high potential research targets remain undeveloped, it appears likely that an accelerated R&D program could substantially lift many of the technological barriers that currently impede EOR. Examination of the potential of accelerated public/private R&D required:

- Definition of the technological achievements necessary for each target.
- Determination of the amount of production from each target, should the achievements be realized.

- Estimation of the likelihood of success in achieving these advances.

The Accelerated R&D Case analyzed here assumes that significant resources and effort are devoted to R&D in enhanced oil recovery by both the private and public sectors. In all, twenty programs, oriented toward the problems of specific reservoir targets, were developed. (Additional programs cutting across processes and targets were also developed as required to support the twenty programs.)

Assuming the Standard Economics conditions of upper-tier prices and current tax regulations, accelerated public/private R&D more than doubles expected ultimate recovery over the Base Case, from 11.3 to 26.2 billion barrels. The cost of an R&D program to bring about these improvements was estimated at \$260 million over five years (in constant 1976 dollars).

All techniques are improved by the R&D programs, but the greatest proportional gains are for the surfactant process (becoming economic under conditions where it has been uneconomic), steam drive (gaining over 100%), and carbon dioxide miscible (gaining about 85%).

More specifically, the technology advances, production results, expectations and timing for the five processes under Standard Economics conditions are:

1. Steam Drive

- Improving the recovery efficiency in shallow, heavy oil reservoirs, by adding chemical agents to the steam and improving volumetric conformance, yields an incremental expected ultimate recovery of 2.3 billion barrels (0.75 mean expectation of success; to start after 1981).
- Using non-petroleum fuels to power steam generators adds 1.0 billion barrels of expected ultimate recovery (0.33 expectation of success; after 1979).
- Overcoming emissions problems and developing markets for heavy West Coast crude, in the face of the arrival of North Slope oil, adds no incremental ultimate recovery but accelerates expected production by 380 MB/D in 1990 (0.50 expectation of success; after 1979).
- Improving injection string insulation or using down-hole steam generators to take steam drive to reservoirs between 2,500 and 5,000 feet produces incremental expected ultimate recovery of 1.6 billion barrels (0.45 expectation of success; after 1982).
- Using improved steam drive in shallow, light oil reservoirs that are uneconomic for chemical or miscible

processes adds 1.8 billion barrels to expected ultimate recovery (0.57 expectation of success; after 1982).

- Adapting steam drive to non-flowing oils could add up to 600 thousand barrels to expected ultimate recovery (0.12 expectation of success; after 1985).

2. In situ combustion

- Improving predictability and control of the process when applied to heavy oil reservoirs adds 120 million barrels to expected ultimate recovery (0.30 expectation of success; after 1982).

3. Carbon dioxide miscible flooding

- Accelerating the application of the process and improving its sweep efficiency by 50% yields an expected 3.4 billion barrels of incremental recovery from high oil saturation reservoirs in the Southwest and Rockies (0.57 expectation of success; after 1979).
- Removing the constraint on carbon dioxide supplies by developing low cost, manufactured sources adds no ultimate recovery but accelerates production by 80 MB/D in 1990 (1.00 expectation of success; after 1982).

- Making the process effective in reservoirs with less than 45% residual oil saturation in the Southwest and Rockies yields 240 million barrels of incremental expected ultimate recovery (0.40 expectation of success; after 1979).
- Applying the process to Gulf Coast sandstone reservoirs adds 200 million barrels estimated ultimate recovery (0.67 expectation of success; after 1980).
- Applying the process in all other sandstone reservoirs yields about 190 million barrels of expected ultimate recovery (0.32 expectation of success; after 1980).

4. Surfactant/Polymer

- Making the process more predictable and controllable and reducing the costs of surfactant adds, in the Illinois Basin, 450 million barrels of incremental expected ultimate recovery (0.75 expectation of success; after 1983).
- Applying the process to California sandstone reservoirs yields 650 million barrels of expected ultimate recovery (0.38 expectation of success; after 1983).

5. Polymer augmented waterflooding

- Improving the sweep efficiency of the process adds 70 million barrels of expected ultimate recovery (0.50 expectation of success; after 1982).

6. Special Targets -- Additional incremental production could come from special efforts to apply EOR techniques to reservoirs with special problems, but very large potential, including:

- North Slope
- Offshore areas
- Low recovery reservoirs (e.g., Spraberry Trend)
- Elk Hills

Aggressive public/private R&D not only adds to expected ultimate recovery, it accelerates production (Figure 6). Production from steam flooding would be fully applied by 1990. Production from carbon dioxide processes begins more slowly, but makes substantial contribution to the total production rate by 1990. Production from the surfactant processes appears in significant quantities only after 1990 due to the more extensive basic research required to develop this technique fully. Collectively, the EOR techniques, advanced through targeted public/private R&D, are expected to accelerate production to over four times the Base Case rate by 1990.

ECONOMIC INCENTIVES COUPLED WITH ACCELERATED R&D

Providing economic incentives and accelerating collaborative public/private R&D, of course, are not mutually exclusive. The Federal government could decide to pursue both options in the context of an overall energy policy. To examine the potential of such combinations, the sensitivity of the combined Accelerated R&D and Base Cases to changes in price were examined. Production at world price (\$13.00/B) and at alternative fuel price (\$20.00/B) were compared to production at upper-tier price. In general, R&D investments are expected to be sensitive to price. The assumptions regarding this sensitivity used in the present study were based on the interviews with the fourteen companies described above.

The rate of private R&D at \$13.00/B was assumed to be the same as the rate at upper tier price, in accord with the consistently expressed opinions of R&D managers of producing companies. These managers were not, however, consistent in their views of the level of private R&D at considerably higher prices. At \$20.00/B, accelerated private R&D was assumed, but this acceleration was seen to be limited by several factors:

- Organizational adjustment to a dramatic price increase and uncertainty about the stability of the higher price would defer investment by industry for some period.

- Relaxation of some of the major constraints, e.g., environmental regulations, may require collaboration of the Federal government regardless of oil price.
- Even at higher prices, the R&D cost burden to individual companies of achieving the required technological advances may not be recouped from the properties held by that company alone, thus inhibiting R&D investments to levels below optional for the industry or the nation when viewed as a whole.

In the absence of historical data, only assumptions concerning the price elasticity of private R&D could be advanced. These assumptions would affect the size of the Base Case estimates but would not affect the magnitude of the overall estimates of the potential. Regardless of who performs the necessary R&D, technological advance is required if the potential is to be realized, but the distinction between Base and Accelerated Cases is less distinct at the higher prices.

Expected ultimate recovery increases with rising prices for all techniques (Figure 7), especially for surfactant, carbon dioxide, and steam drive. At world prices, expected ultimate recovery rises to 30.1 billion barrels -- 3.9 billion barrels over the upper-tier price level. At alternative fuel price, the increase is to 37.1 billion barrels -- 10.9 billion barrels over the upper-tier price level.

Similarly, the rate of production is affected by the combination of R&D and price policies (Figure 8). The rise in production rate due to targeted public/private R&D noted earlier at upper-tier prices is further accelerated by additional economic incentives. By 1990, the production rate for the Accelerated R&D Case at upper-tier prices is about 2.6 MMB/D. At world price, the rate rises to nearly 3.3 MMB/D; at alternative fuel price, almost 4.2 MMB/D are produced.

The effects of combinations of accelerated R&D and economic incentives provided through tax policies were also examined. As was found for the Base Case alone, mandatory capitalization of injection chemicals impedes surfactant/polymer and carbon dioxide applications under the Accelerated R&D Case. Moderate changes in the investment tax credit again have little effect.

SUMMARY OF THE RESULTS

Enhanced oil recovery can make a major contribution to the domestic supply of crude oil during the next twenty years. The magnitude, timing, and costs to consumers and taxpayers of EOR production, however, are highly sensitive to Federal policies. The results of this study point to several conclusions that are relevant to these policies:

- Enhanced oil recovery could add from less than 4 to more than 37 billion barrels of ultimate recovery, depending on decisions by Congress and the Administration.

Given current domestic reserves of about 32 billion barrels, this increment represents a substantial potential addition to domestic petroleum supply.

- Enhanced recovery is currently restricted more by technological problems and non-process constraints than by economics (Figure 8). Only for a few isolated targets could raising prices fully substitute for accelerated, targeted R&D (c.f., Figures 5, and 6).
- Without an accelerated public/private research and development program, EOR will add a small but valuable increment to domestic production -- about 600 thousand barrels per day in 1990 (Figure 9).
- With a targeted, successful R&D program, enhanced recovery could contribute substantially to domestic production during the period of greatest dependence on imports:
 - At upper-tier prices, about 2.6 MMB/D by 1990 could be produced (Figure 9).
 - At higher prices, the 1990 production rate would be still higher -- 3 MMB/D at world prices; 4.2 MMB/D at alternative fuel price.

- Further analysis, taking into account costs to consumers, world trade balances, national security, and environmental costs of alternative fuels would be required to establish an optimum combination of economic incentives and accelerated programs of public/private R&D in enhanced oil recovery.

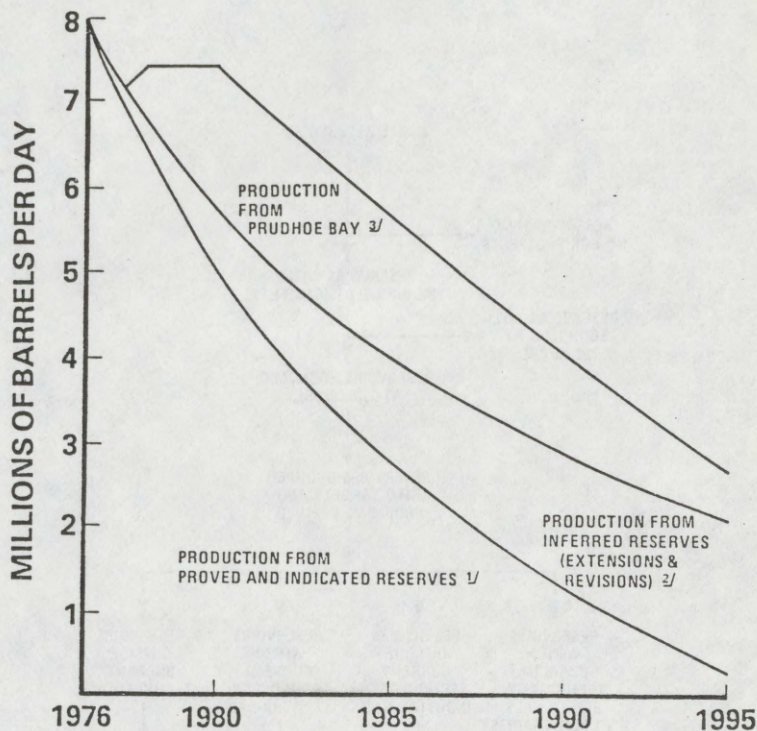
ACKNOWLEDGEMENTS

The authors express their appreciation to the Federal agencies that supported these studies, and to their able staffs; to the many research and production managers in the industry who shared their time, data, and experience; and to Dr. Todd Doscher, who contributed his extensive expertise in EOR research, development, and application.

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7. T.M. Doscher and F.A. Wise, "Enhanced Crude Oil Recovery Potential -- An Estimate", Improved Oil Recovery SPE Symposium, March 22-24, 1976, pp. 7-26. (SPE 5800)
8. U.S. Geological Survey, Circular 725, 1975.

Figure 1 - Projected Production by Conventional Methods from Known U.S. Reservoirs, 1976-1995



SOURCES: 1/ AMERICAN PETROLEUM INSTITUTE, *RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS, AND NATURAL GAS IN THE U.S. AND CANADA AS OF DECEMBER 30, 1975*; LEWIN & ASSOCIATES, INC. FOR FEDERAL ENERGY ADMINISTRATION, *DECLINE CURVE ANALYSIS*, 1976.

2/ U.S. GEOLOGICAL SURVEY, *CIRCULAR 725*, 1975.

3/ FEDERAL ENERGY ADMINISTRATION, *NATIONAL ENERGY OUTLOOK*, 1976.

Figure 2 - Flow of Reservoirs Through the Analysis

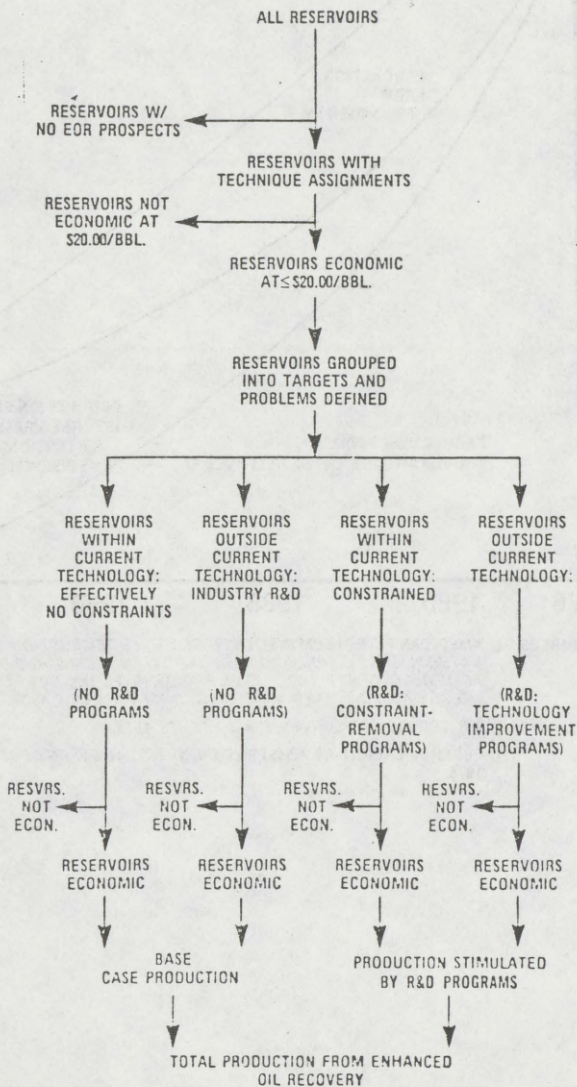
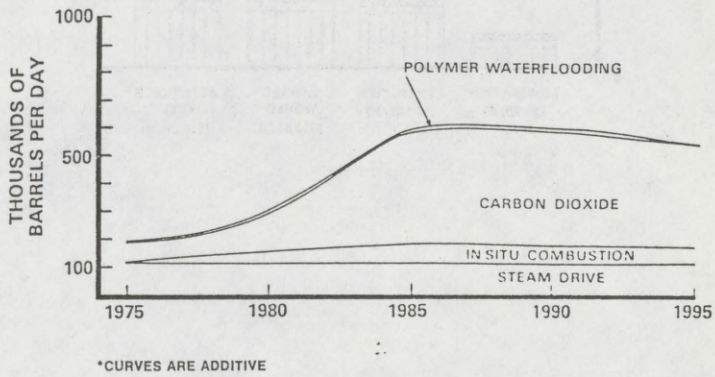


Figure 3 -. Expected Production Rates for Total Base Case (Standard Economics)*



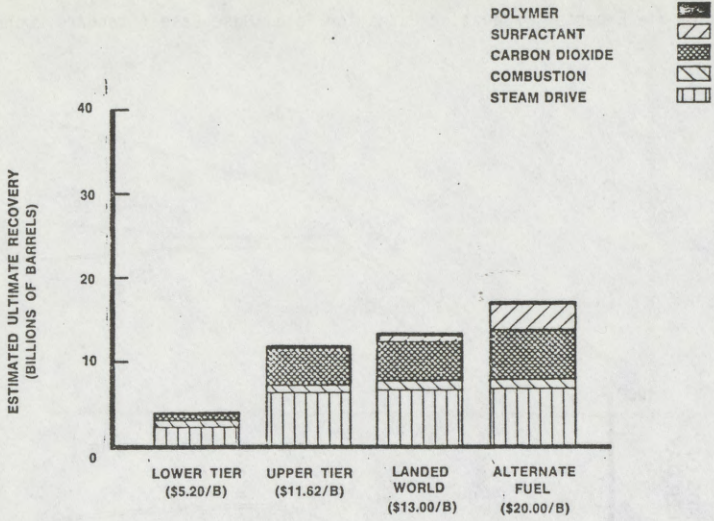


Figure 4 - Sensitivity of Ultimate Recovery to Price Contingencies

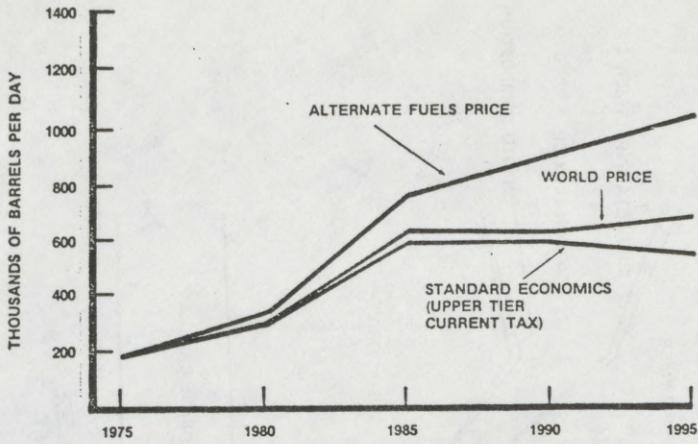
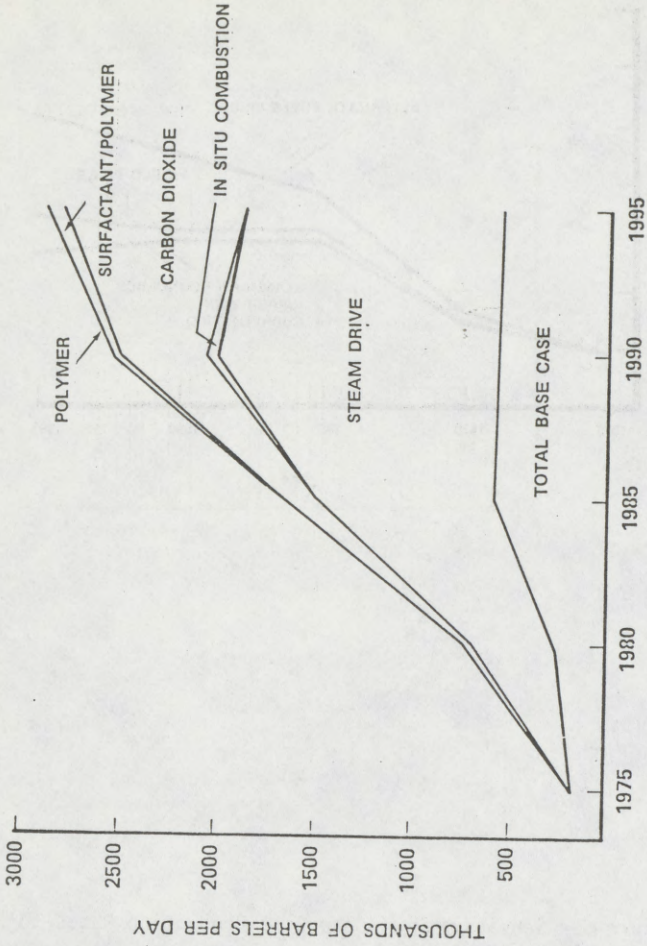


Figure 5 - Sensitivity of Base Case Production Rates to Price Contingencies (Base Case)

Figure 6 - Expected Production Rates for Total of Base Case and Accelerated R & D Case* (Standard Economics)



*CURVES ARE ADDITIVE

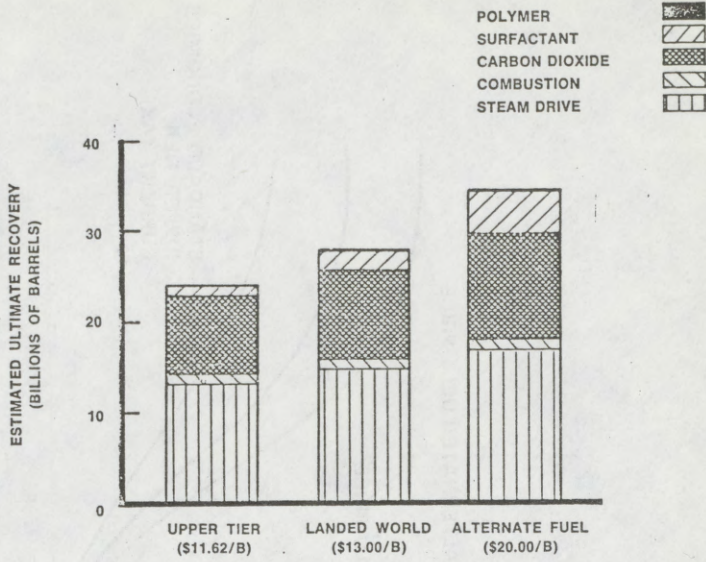


Figure 7 - Estimated Ultimate Recovery for Combined Base Case and Accelerated R & D Case at Selected Prices

Figure 8 - Expected Production Rates Under Selected Oil Prices
(Total of Base Case and Accelerated R & D Case)

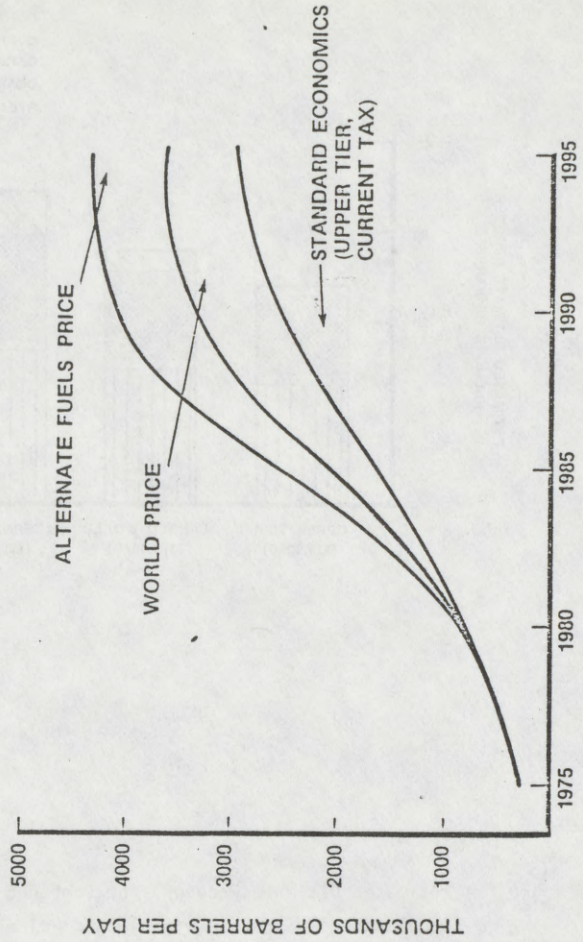


Figure 9 - Possible Contributions of Enhanced Oil Recovery to Production from Known, Domestic Reserves (Standard Economics)

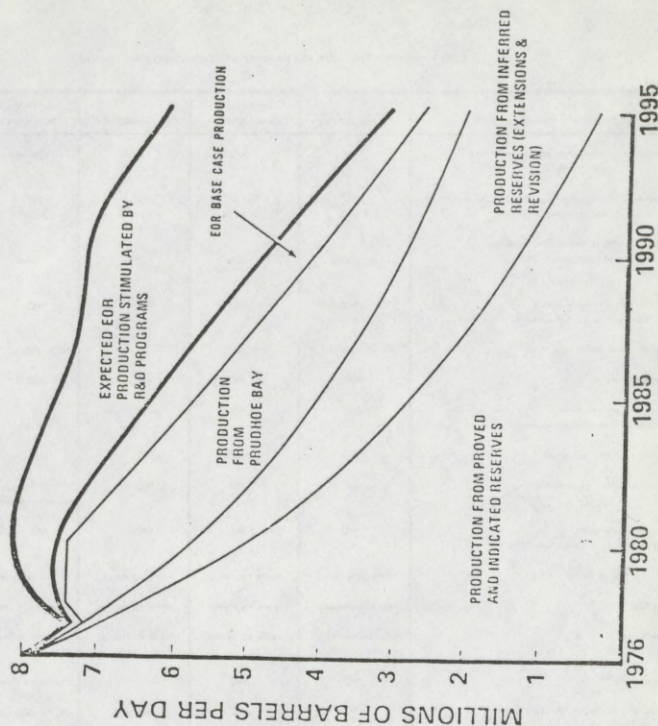


Table 1

CRITERIA FOR THE APPLICATION OF SELECTED EOR METHODS

SCREENING PARAMETERS	STEAM DRIVE	IN SITU COMBUSTION	CO ₂ MISCIBLE	MICELLAR/ POLYMER	IMPROVED WATERFLOOD
Viscosity - centipoise (cp) at reservoir conditions	NC ¹	NC	< 12 cp	< 20 cp	< 200 cp
Gravity - (Other than California Crude - ⁰ API) (Calif. crude)	> 10 ⁰ (> 10 ¹)	(10-45 ⁰) (10-45 ⁰)	> 30 ⁰ (> 26 ⁰)	> 28 ⁰ (> 25 ⁰)	15 > 18 ⁰ (> 16 ⁰)
Fraction of Oil Remaining in Area to be Flooded (before EOR) - %PV	50% ²	50% ²	25%	25%	50%
Oil Concentration - B/A/F Porosity & Oil Saturation	> 500 B/A/F > 0.065	> 400 B/A/F > .05	NC	NC	NC
Depth - feet	< 5,000	> 500 ³		NC - 8500 ^{1,3,5}	NC - 8500 ^{1,3,5}
Temperature - °F	NC	NC	NC	< 200 ⁰ F ⁵	< 200 ⁰ F ⁵
Original Bottom Hole Pressure - Pounds per square inch (psi)	NC	NC	> 1,500 psi	NC	NC
Net Pay Thickness - feet	> 20 ⁴	> 10 ⁴	NC	NC	NC
Permeability - millidarcy (mD)	NC	NC	NC	> 20 mD (with polymer drive)	> 20 mD
Transmissibility (Permeability x Thickness/Visc.)	> 100	> 20	NC	NC	NC
Natural Water Drive ⁴	none to weak	none to weak	none to weak	none to weak	none to weak
Gas Cap ⁴	none to minor	none to minor	none to minor	none to minor	none to minor
Fractures	NC unless extreme	none to minor	none to minor	none to minor	none to minor
Lithology	NC	NC	NC	sandstone only ⁵	NC
Salinity - parts per million (ppm) TDS	NC	NC	NC	< 50,000 ppm ⁵	NC
Hardness - ppm - calcium & magnesium	NC	NC	NC	< 1,000 ppm ⁵	NC
Comments	• Porosity & thickness (high) • 10-acre spacing • Economic freshwater available • Economic fuel available • High net to gross pay • Low clay content	• High dip preferred • Porosity & thickness high • 40-acre spacing • Low vertical permeability preferred • Preferred temperature > 150⁰F • High net to gross pay	• Thin pay preferred • High dip preferred • Homogeneous formation preferred • Porosity & thickness low • Natural CO₂ availability • Low vertical permeability in horizontal reservoirs	• Homogeneous formation preferred • Low clay content • Porosity & thickness (high) • Prefer water-flood sweep > 50%	• Use with or prior to waterflood • Low calcium and clay content • Porosity & thickness (high)

NOTES:

NC Not a critical factor (for all).

In portion of field to be flooded. Assuming 80 percent of area of reservoir contains 95 percent of remaining oil, the oil saturation for the total field becomes 42 percent of pore volume.

8500 ft. is approximately the depth at which the temperature constraint of 200 F will be reached.

These criteria apply to reservoirs with substantial remaining primary recovery.

Considered a constraint under current technology.

This table is an analytic tool based on analysis of numerous EOR projects; it should not, however, be interpreted as a strict guide to the applicability of a given process to a specific reservoir.

BIOGRAPHICAL SKETCHES

J. P. Brashear is a principal with Lewin and Associates, Inc. of Washington, D.C. He holds an AB from Princeton, an MBA from Harvard, and a Ph.D. from the University of Michigan. Brashear joined Lewin three years ago, where he has served as project manager on numerous studies of the impact of Federal policy on oil and gas production.

Vello A. Kuuskraa is Vice President and partner of Lewin and Associates, Inc. He holds a BS from the University of North Carolina and an MBA from the Wharton School of the University of Pennsylvania. He heads the firm's consulting practice in energy policy and economic feasibility studies.

ATTACHMENT BLIST OF EOR TARGETS

Below is the exhaustive list of high potential targets. They are listed by the most applicable EOR technique, the generic reservoir characteristics/geographic locale, and the specific technological achievements to be made:

1. Steam Drive

- Shallow, heavy oil reservoir, less than about 2,500 feet, with unstimulated influx, and with oil gravities greater than about 11° to 12° API (and less than 25° API).
 - Apply and extend the current technology
 - Improve recovery efficiency
 - Use cheaper non-petroleum fuels (rather than crude oil and fuel oil) to generate steam
 - Overcome emission problems or secure a variance on emissions
 - Examine alternative use of heavy crudes and/or alternative markets for West Coast oil.
- Deeper, heavy reservoirs, deeper than 2,500 feet, with unstimulated influx, and with oil gravities greater than about 12° API (and less than 25° API).
 - Overcome heat loss problems in injection string, design reliable injection string, and develop efficient techniques for recuperating produced heat in deeper, heavy oil reservoirs.
- Light oil reservoirs (greater than 25° API), typically marked by thinner pays, lower permeability, and lower oil saturations than the first group of reservoirs listed above.

- Extend the application of the process to such reservoirs by using cheaper fuels or generating steam.
- Heavy oil reservoirs with no influx and with gravities between 8° API and 11° API.
- Extend the application of the process to non-flowing oils.

2. In Situ Combustion

- Heavy oil reservoirs
 - Apply the current technology
 - Extend the application of the in situ combustion process by defining the key process and reservoir characteristics
 - Overcome emission problems or secure a variance on emissions.

3. CO₂ Miscible

- Carbonate reservoirs in the Southwest (West Texas and Southeastern New Mexico) and Montana with high oil saturations (current saturations of 50% or greater).
 - And with high anticipated waterflood residual oil saturations (average residual saturations of 45% or greater)
 - apply and extend the technology as currently defined
 - improve recovery efficiency
 - develop adequate and cheaper supplies of carbon dioxide.

- And with low anticipated waterflood residual oil saturations (average residual saturations of less than 45%)
 - accelerate the application of the process prior to the waterflood residual being reached, and achieve improved efficiency using acceptable oil/CO₂ ratios.
- Carbonate reservoirs in the Southwest and Montana with current oil saturations already reduced by waterflooding to 45% or less.
 - Extend the application of the process to reservoirs with low current oil saturations.
- Gulf Coast (East Texas and Southern Louisiana) sandstone reservoirs with a significant dip, having low saturations, due to efficient waterfloods.
 - Make the process economic in these high dip reservoirs by gravity-stabilizing the CO₂ drive.
- Other sandstone reservoirs, especially in California and Appalachia.
 - Extend the application of the process to these tight sandstone reservoirs with varying degrees of depletion.

4. Surfactant/Polymer

- Basic surfactant: improve recovery efficient for target reservoirs throughout the U.S. by the development of surfactant systems which are compatible with (maintain their effectiveness in) the sub-surface environment.

- Shallow, homogeneous sandstone reservoirs (e.g, Illinois basin).
 - Assure adequate recovery efficiency and make the process conventional in shallow Illinois sandstones where economic pilots have indicated proximate success.
- California sandstone reservoirs.
 - Extend the application of the process to California sandstone reservoirs, which generally are laden with clays (high adsorptive and cation exchange values).
- Gulf Coast (East Texas and Southern Louisiana) sandstones marked by high salinity, high temperature, but with potential for high fluid flow velocity and relatively high homogeneity.
 - Improve recovery efficiency and extend the application of the process to Gulf Coast sandstone reservoirs.
- Other sandstones, including the Mid-Continent, Rocky Mountains, and Appalachian regions.
 - Examine the application of the surfactant recovery system in these sandstone reservoirs, which will range in clay content and permeability variance.

5. Improved Waterflooding

- General reservoirs
 - Apply the technology as currently defined by use of stable viscosity-increasing additives (water soluble polymers and foams)

- Extend the application of the process by improving the effectiveness of viscosity increasing additives.

6. Special Targets

- Low recovery reservoirs, such as Sprayberry Trend.
 - Seek novel systems for increasing the recovery efficiency of Sprayberry Trend and other low-recovery reservoirs.
- Virgin or partially depleted reservoirs, such as North Slope and Elk Hills.
 - Assess the value of early versus step-wise implementation of enhanced recovery processes in giant virgin and partially depleted reservoirs.
- Time Window Reservoirs, such as offshore Louisiana, where abandonment may foreclose substantial EOR opportunities.
 - Study the effectiveness and urgency of implementing enhanced recovery methods in the Gulf Coast offshore areas, where abandonment may be imminent.

Special Emphasis

- Reservoirs where precise knowledge of the residual is critical and in question.
 - Initiate a major residual oil measurement program.

This listing served to identify the first priority targets. As additional information is gained from the laboratory and field tests, revisions, additions, and re-partitioning of the resource base would be essential for maintaining an up-to-date set of R&D targets in enhanced oil recovery.

ATTACHMENT CANALYSIS POLICY OPTION 3-B -- DEREGULATION OF OIL PRODUCTION IN ASSOCIATION WITH EORA. The Policy Option

One means for encouraging EOR production would be to provide economic incentives by releasing all oil (rather than just incremental oil) from bonafide EOR projects.

Reservoirs or properties amenable to EOR and that have not yet been abandoned or reached stripper oil status, may contain substantial amounts of controlled price, "lower or upper-tier" (primary/secondary) oil. Releasing this controlled price oil from the segment of the reservoir under enhanced oil recovery would provide front-end capital and would improve the economic attractiveness of EOR projects.

B. Theoretical Analysis of the Incentive

Assuming that a field had the current national average of 50% "lower-tier" oil (at \$5.40 per barrel), 35% "upper-tier" oil (at \$12.00 per barrel) and 15% stripper oil (at world price of \$14.00 per barrel), releasing this oil would add \$5.00 per barrel to the average allowable sales price, as shown below:

<u>Allowed Oil Price Classifications</u>	<u>Effect of Releasing Production from Price Controls</u>
"lower-tier"	\$5.00 → \$14.00 (0.50 bbls x \$8.60 bbls = \$4.30)
"upper-tier"	\$12.00 → \$14.00 (0.35 bbls x \$2.00 bbls = \$0.70)
"stripper"	\$14.00 → \$14.00 (0.15 bbls x 0 bbls = 0)
Average Price	\$9.00 → \$14.00

Assuming 1 barrel of existing production would be associated with every 2 barrels of EOR production, the effect of this incentive would be to add \$2.50 to the realized sales price of EOR oil (and provide front-end capital) as shown below:

Lewin and Associates *Prepared For: [illegible]*

<u>Hypothetical Condition</u>	<u>Value to EOR Production</u>
2 barrels of EOR oil at \$14.00/bbls. plus 1 barrel released oil at value of \$5.00/bbl.	$(2 \times \$14.00) +$ $\$5.00 = \33.00 $\frac{\$33}{2} = \$16.50/\text{bbl.}$ equivalent price for EOR oil

The effect of this incentive would be to allow producers (assuming each reservoir had an average distribution of price controlled crude) to produce EOR at costs + ROR up to \$2.50 above world oil prices and realize the added incentive of an earlier cash flow.

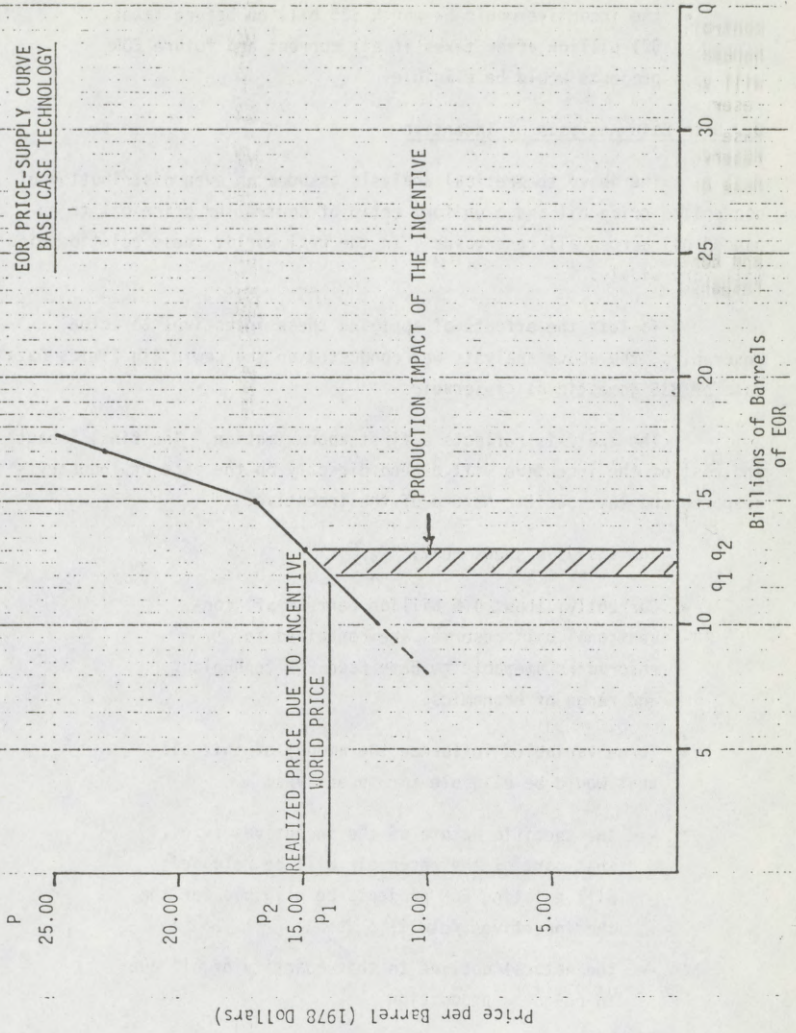
C. Theoretical Analysis of Impact

The effect of this incentive (shown on Exhibit 2) is to shift the economic break-even point of the "price (marginal cost + ROR)/supply" curve from p_1 to p_2 (from \$14.00 to \$16.50 per barrel) and thus increase the amount of EOR oil from q_1 to q_2 -- from 12 to 14 billion barrels.

Under this hypothetical analysis the value of the incentive (and the additional cost to the consumer) could range from 5 to 35 billion dollars before taxes and 2 to 16 billion dollars after taxes depending on what types of EOR projects would be eligible for the incentive. Assuming the EOR price/supply curve for Base Case EOR Technology (Exhibit 2) and a ratio of 0.5 barrels of released oil valued at \$5.00/bbl. for every 1 barrel of EOR oil:

- The incentive (and the costs to the consumer) would be worth \$5 billion before taxes, \$2 billion after taxes if only the marginal EOR projects (i.e., those requiring a price, cost + ROR, greater than p_1) would be eligible
- the incentive would be worth \$25 billion before taxes, \$12 billion after taxes if all future EOR projects would be eligible for the incentive.

EXHIBIT 2

EOR PRICE-SUPPLY CURVE
BASE CASE TECHNOLOGY

- the incentive would be worth \$35 billion before taxes, \$21 billion after taxes if all current and future EOR projects would be eligible.

D. Data Base Analysis of Incentive

The above theoretical analysis assumed an even distribution of controlled price oil and a uniform ratio of controlled price oil to enhanced oil across all reservoirs. In the real world, these relationships will vary widely.

To test the effects of applying these incentives to actual reservoirs, the above analysis was conducted on the Lewin Big Fields Data Base of 835 domestic oil reservoirs.

The analysis reflects a first approximation. The final impact and cost of the incentive will depend directly on the pace of industry's response and the specific nature of the incentive.

The analysis shows that:

- Currently, about 4.5 billion barrels of "conventional oil" reserves are contained in reservoirs amenable to Base Case EOR technology and range of economics.
- Three variables influence the amount of this oil that would be eligible for incentives:
 - the specific nature of the incentives (e.g., what part of the reservoir will be released; will existing EOR projects be eligible for the the incentives, etc.?)
 - the natural decline in this quantity of oil due to on-going production

- the changing value of the incentive as the mix of "lower-tier", "upper-tier" and stripper oil changes over time.

Applying a standard 10% decline curve to "lower-tier" oil and assuming that extension drilling and additional waterflooding help maintain the quantity of "upper-tier" and stripper oil at approximately their current levels:

- About 4 billion barrels would be available for release when the incentives took effect in 1980 with each barrel having an average value of \$4.80.
- This quantity declines and drops in value with the passage of time and before an oil producer can apply a bonafide EOR technique to a property.
- Assuming that 10 years is required to fully apply the EOR technology across the reservoir,
 - a. If all projects were eligible
 - about 3 billion barrels of oil would be released
 - the average value would be \$4.00 per barrel
 - b. If only marginal projects were eligible
 - about 0.5 billion barrels of oil would be released
 - the average value would remain at \$4.00 per barrel

As a first approximation, the program would provide incentives and thus cost ranging from \$2 to \$12 billion before taxes, \$1 to \$7 billion after taxes.

The average incentive would add about \$1.00 per barrel additional cash flow to an EOR project. Under current EOR technology and world prices this would, in turn, add approximately 1 billion barrels to domestic oil reserves.

E. Combining Economic Incentives with Technological Advance

The effect of these economic incentives would be greatly augmented when advanced EOR technology begins to be applied to the resource.

Assuming that successful research and development has shifted the price/supply curve, now the incentive would add 2 to 3 billion barrels to an already larger base of EOR reserves.

From a public policy perspective it appears that combining R&D directed toward technological advance with economic incentives provides the highest payoff option.

Senator HASKELL. Mr. Kuuskraa, in your loan guarantees you indicate basically picking the projects that have the greatest payoffs, I gather.

Mr. KUUSKRAA. Yes, sir.

Senator HASKELL. What do you mean by a "proportional sharing of investment capital and project defaults"?

Mr. KUUSKRAA. That you might require the producer to put up, say, half of the capital and, should the project default, incur half of the loss.

Senator HASKELL. Oh, yes. I would agree with that.

Now, do you think on the price guarantees, would you recommend that they be aimed at the projects with the highest payoff possibilities?

Mr. KUUSKRAA. Given the large amounts of capital that would be required, yes, sir. Since you would only have a limited amount of money, you would have to limit the number.

Senator HASKELL. Right, because I think in Senator Hart's bill, I think he has got \$200 million for—

Mr. KUUSKRAA. Yes; that would not go very far.

Senator HASKELL. That is correct.

Well, I am sorry that time constraints forbid, but I will look forward to reading your testimony with interest.

Senator Bartlett.

Senator BARTLETT. Mr. Chairman, I have no questions. I compliment Mr. Kuuskraa for his testimony and would say that unanimous consent was obtained on the floor that we can extend this past 12 and, as I understand it, we can even go past 12:30. I think he had about 13 minutes counting questions, and I think it would be fair if the others had the same amount.

[Subsequent to the hearing Mr. Kuuskraa supplied the following information:]

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C., July 20, 1978.

Mr. VALLO A. KUUSKRAA,
Lewin & Associates, Inc.,
Washington, D.C.

DEAR MR. KUUSKRAA: At the July 17 hearing of the Committee on Energy and Natural Resources there was not enough time to discuss a number of issues which are relevant to the subject. Accordingly, I am enclosing a set of supplemental questions which I hope can be answered for the record.

I look forward to receiving your responses to supplemental questions. In order to expedite printing of the hearing record, these responses should be provided by close of business, August 4, 1978.

Questions about this request should be directed to Benjamin S. Cooper or James T. Bruce at 224-9894.

Sincerely yours

FLOYD K. HASKELL,
U.S. Senator.

SUPPLEMENTAL QUESTIONS FROM THE COMMITTEE ON ENERGY AND NATURAL RESOURCES

1. How much oil will be covered in each year between now and 1985 by the deregulation provisions of:

- (a) S. 2999 as introduced by Senators Hart, Domenici and Haskell;
- (b) S. 2623, as introduced by Senator Bentsen and also as interpreted by Senator Bentsen at the July 17 hearing: decontrolling oil produced within "the area affected by the tertiary recovery project";
- (c) the amendment proposed by Senator Bartlett at the hearing (a copy is attached);

(d) the amendment proposed by Rep. Wright (p. H6367 of the Congressional Record of July 10, 1978).

What additional revenues will accrue to crude oil producers in each of these years from each of these amendments?

2. In your discussion of loan guarantees you call for limits on the size of projects, a cap on total financial exposure, and requiring a proportional sharing of investment capital and project defaults. Would you elaborate on these suggestions?

3. Do you think the price guarantees of S. 2999 should be aimed at the projects with the highest payoff? How do you recommend we make that determination?

RESPONSE TO SUPPLEMENTAL QUESTIONS FROM THE COMMITTEE ON ENERGY AND NATURAL RESOURCES

Question 1. How much oil will be covered in each year between now and 1985 by the deregulation provisions of

(a) S. 2999 as introduced by Senators Hart, Domenici and Haskell;

(b) S. 2623, as introduced by Senator Bentsen and also as interpreted by Senator Bentsen at the July 17th hearing: decontrolling oil produced within "the area affected by the tertiary recovery project";

(c) the amendment proposed by Senator Bartlett at the hearing;

(d) the amendment proposed by Rep. Wright (p. H6367 of the Congressional Record of July 10, 1978).

What additional revenues will accrue to crude oil producers in each of these years from each of these amendments?

Answer. (a) Amount of oil to be released and revenue to producers from S. 2999: This bill proposed to release all incremental EOR from price controls; thus, the otherwise "lower-tier" and "upper-tier" EOR oil would be released. The yearly amounts would be as follows (in millions of barrels and millions of dollars per year).

Year	Total EOR production	Total released EOR oil (nonstripper EOR)	Gross revenues under current provisions	Gross revenues under S. 2999	Additional gross revenues
1979	102	88	\$923	\$1,428	\$505
1980	110	91	996	1,540	544
1981	124	106	1,122	1,736	614
1982	139	117	1,258	1,946	688
1983	153	131	1,385	2,142	757
1984	168	142	1,520	2,352	832
1985	182	153	1,647	2,548	901

However, it is unlikely that the higher quantities of EOR production would be forthcoming without these provisions. Thus, imported oil at world oil prices would need to fill the demand. As such, there would be little net cost to the consumer for the higher level of EOR production.

(b) Amount of oil to be released by and revenues to producers from S. 2623: This bill proposes to release all the oil production from the area affected by the tertiary project. Thus, in addition to EOR oil in the project, all controlled oil remaining to be recovered (by waterflooding or other means) would be released.

It is impossible to predict how individual operators would actually respond to the incentive. The analysis assumes that the operator would proceed according to the spirit and intent of the amendment, apply only "bona fide" EOR techniques designed to recovery substantial amounts of the residual oil to waterflooding and would not "gimmick" the incentives just to obtain release of controlled oil. Under this assumption the yearly amounts would be as follows (in millions of barrels per year).

Year	Total EOR production	Released EOR oil (nonstripper EOR)	Other re-released oil	Total re-released oil
1979	102	88	24	112
1980	110	91	23	114
1981	131	113	27	140
1982	153	131	29	160
1983	175	150	32	182
1984	197	168	34	202
1985	219	186	35	221

Additional revenues. In addition to providing a world oil price of \$14.00 per barrel, this bill would provide release of "lower-tier" oil, assumed priced at \$5.50 per barrel and "upper-tier" oil, assumed priced at \$12.00 per barrel. Each barrel of released EOR is assumed to be associated with 0.10 barrel of "upper-tier" oil and 0.09 to 0.17 barrels of "lower-tier" oil (depending on the decline rate for "lower-tier" oil). The yearly revenues would be as follows (in millions of dollars per year).

Year	Gross revenues under current provisions	Revenues under S. 2623	Other released oil	Total gross revenues under S. 2623	Additional gross revenues
1979.....	\$923	\$1,428	\$145	\$1,573	\$650
1980.....	996	1,540	134	1,674	678
1981.....	1,186	1,834	157	1,991	805
1982.....	1,385	2,142	160	2,302	917
1983.....	1,584	2,450	170	2,620	1,036
1984.....	1,783	2,758	177	2,935	1,152
1985.....	1,982	3,066	179	3,245	1,263

To the extent these incentives stimulate higher EOR production that in turn would displace imports, the net cost to the consumer would be small. (In each year, the domestic tax payments on EOR oil would exceed the amount of incentive provided by the released oil provision.)

(c) Amendment Proposed by Senator Bartlett: Nearly all domestic reservoirs are (or soon could be) under some form of pressure maintenance, secondary recovery or enhanced recovery. Excluding North Slope, Alaska, 7.5 million barrels per day and ultimately 20.2 billion barrels of oil would now be or could be exempt from price regulations.

Assuming that release of oil increases the composite price from about \$9.05/B to \$14.00/B, this would add \$4.95/B to the sale price for oil.

At 7.5 million barrels per day current production, 2.7 billion barrels per year, and an increase in price an average of \$4.95 per barrel, this would increase gross revenues by \$13.4 billion per year starting in 1979.

Assuming 20.2 billion barrels would be released, this amendment would ultimately increase gross revenues by \$100 billion.

(d) Amendment Proposed by Representative Wright: We have insufficient data to prepare a thorough appraisal of this amendment.

Question 2. In your discussion of loan guarantees you call for limits on the size of projects, a cap on total financial exposure, and requiring a proportional sharing of investment capital and project defaults. Would you elaborate on these suggestions?

Answer. S. 2999 stipulates that the outstanding indebtedness and commitment to be guaranteed shall at no time exceed \$200,000,000. Since even a moderate size field-wide EOR project may produce over 20 million barrels of EOR, only 5 or 6 moderate size projects could be eligible at any given time. To increase the impact of the loan guarantee program, one may wish to limit the size of the project eligible for the loan guarantee to a range of \$10 to \$20 million.

For ensuring economic efficiency and increasing the impact of the program, it seems prudent to require that the operator provide a proportional share of the investment capital and share the downside risks. Striking a balance between proportional sharing (for economic efficiency) and access to capital might suggest that the producer "stand behind" 25 percent to 50 percent of the investment capital and the government guarantee the remaining 50 percent to 75 percent.

Question 3. Do you think the price guarantees of S. 2999 should be aimed at the projects with the highest payoff? How do you recommend we make that determination?

Answer. Price guarantees can be an efficient mechanism for stimulating producers to undertake EOR projects in anticipation of (rather than after) increases in world oil prices. Since the goal is acceleration of EOR production and, the funds are limited (ranging from \$20 million in 1980 to \$100 million in 1983), channeling these incentives to the areas of highest EOR production potential would increase the impact of the incentives.

One means for making such a determination would be for the state commissions and DOE to identify the domestic reservoir types/EOR techniques according to their potential for near-term (or ultimate) production. These prospects would be ranked in priority order and would assist DOE officials allocate "price guarantee" resources among competing EOR proposal, from production companies. Such an approach would be relatively straight forward to accomplish since DOE has already conducted much of the essential data gathering and EOR technology assessments.

Senator HASKELL. We will just see how things go along here. Do I understand we can go beyond 12:30?

Well, if we can go beyond 12:30, well, then maybe we don't have to rush it so. I thought 12:30 was the time.

We now have Dr. Goldburg, who is the manager of enhanced oil recovery, Gary Operating Co. of Englewood, Colo., accompanied by Mr. Driver, vice president and general counsel.

Staff corrects me. We cannot go beyond 12:30.

All right; fine. Would you go ahead, sir?

Senator BARTLETT. That was not my information. I specifically inquired of Fred Craft. He said we can go as long as we want.

SENATOR HASKELL. I will suggest that we call the floor.

Go ahead, sir.

STATEMENT OF DR. ARNOLD GOLDBURG, MANAGER, ENHANCED OIL RECOVERY, GARY OPERATING CO., ENGLEWOOD, COLO.; ACCOMPANIED BY MICHAEL J. DRIVER, VICE PRESIDENT AND GENERAL COUNSEL

Dr. GOLDBURG. Mr. Chairman and Senator Bartlett, my name is Dr. Arnold Goldburg and I am manager of enhanced oil recovery for the Gary Operating Co., an independent oil producer with properties in the Rocky Mountain area. In this position I am also project manager of the Department of Energy micellar-polymer pilot demonstration project in the Bell Creek Field, Mont. With me today is Michael Driver, vice president and general counsel of the Gary Operating Co.

I want to thank the committee. This is my first opportunity to testify before a congressional committee. I appreciate the honor and privilege, and I hope I fulfill the responsibilities which this carries with it.

The written version of the Gary Operating Co. testimony, which is before you, covers enhanced oil recovery (EOR) technology, the quantitative contribution of EOR in terms of equivalent barrels of oil per day relative to the contribution of other alternative energy sources, and the economics of a full-field deployment of an EOR technique.

In the time allocated to this oral presentation I want to concentrate on the last area, the full-field EOR economics of a real, smaller independent operator. Gary Operating Co. is the only independent with a micellar-polymer pilot project; and, as such, we have given great thought and analysis to the economic role of the independents in the enhanced oil recovery technologies.

In the interests of time I will just concentrate on two exhibits. If you would turn to exhibit 9 in the transcript—

Senator HASKELL. Incidentally, your full testimony will be included in the record.

Dr. GOLDBURG. Thank you.

Exhibit 9 is "Projected Financial Data for a Full Field Micellar-Polymer Flood in Bell Creek Unit A." I might mention in this regard the question Senator Bartlett put with respect to the need for other incentives vis-a-vis cost sharing. The current DOE commercialization cost-sharing pilots, so called, are only several hundreds of acres in

extent to and do not cover the need to demonstrate the application of EOR technologies to a full field.

Exhibit 9, "Projected Financial Data for a Micellar-Polymer Flood, Bell Creek Unit A. The original oil in place before production was 122 million barrels.

Senator HASKELL. I should interrupt you and say that Senator Bartlett's information was right. We have permission to proceed beyond 12:30.

Dr. GOLDBURG. Thank you very much.

The original oil in place was 122 million barrels. Primary plus secondary production is estimated to be 58 million barrels, which is a very good estimate because we have produced to date about 50 million barrels.

The net worth of this production, and these are real numbers, was \$230 million. Now, each working interest owner, of course, will have a different tax picture, which we are not privy to. But let us assume that the total after tax net worth of the primary plus secondary production to the working interest owners was \$115 million. Let us assume that they put this money into different investments and that, as prudent adventuresome venture entrepreneurs, that they are willing to put 10 percent of their total after-tax net worth generated by this field into a micellar-polymer flood. That would be \$12 million.

To find the tertiary target, we take the 58 million barrels, which will have been produced by primary and secondary from the 122 million barrels of oil originally in place, leaving 64 million barrels in the ground. We estimate, based on our work to date with the pilot, that we will produce 28 million barrels of this available tertiary target, a little over 40 percent.

Now, the chemical costs to produce this 28 million barrels is estimated to be \$140 million. Mr. Langenkamp, in his testimony, indicated a chemical cost expectation of \$10 to \$20 of chemicals per tertiary barrel produced. Our number here is \$5 per tertiary barrel, and the reasons for that are that the Bell Creek field is an excellent prospect for micellar-polymer recovery and also that this number is based on our projected pilot figures which of course, are subject to change if the pilot recovery is less successful than projected.

In other words, this \$140 million of chemicals required to produce the 28 million tertiary barrels is a very conservative number, that is, a minimum estimate.

Now, if we take the \$12 million which we would speculate the working interest owners might be willing to invest in this very high risk project, they are still \$128 million short of the capital needed to carry out this enhanced oil recovery project.

Now, if you will turn to exhibit 12, there is a cumulative net cash flow for this project. What you see here is that if the 40-acre technical pilot is successful, then we would have a go-ahead in the early 1980's, or let us say for the purposes of this exhibit, in 1980. We would then carry out what industry feels to be a prudent approach, which would be to carry out next an economic pilot, which is about one-tenth of the field, in order to see if we can obtain the same efficiency of recovery in a significant part of the field (as was obtained in the pilot) before we actually go ahead and march downfield with a very expensive recovery process.

Let us start in 1985, then, and see what the full field costs would be. We have scheduled the project into three phases, balancing out chemical costs and chemical logistics against the operating costs and the capital costs in order to maximize the rate of return.

You can see the cumulative net cash flow illustrated in exhibit 12; and we have three alternate examples displayed there. The first one is for a projected market price of \$17 a barrel; the second curve is for a projected market price of \$25 a barrel; and the third is for a projected market price of \$17 a barrel and 90 percent financing.

You will notice that at the projected market price of \$17 a barrel, the maximum negative cumulative net cash flow is about \$45 million to be compared with \$12 million which we estimated the working interest owners might be prepared to put into such a high-risk project.

You will notice the next curve of a projected market price of \$25 a barrel has a maximum negative cumulative net cash flow of something like \$35 million, again about three times the amount of money which we would expect the working interest owners, as prudent businessmen, to invest in this project.

The third curve is for \$17 a barrel with 90 percent financing. We see here that the maximum negative cumulative net cash flow of \$6 million would be within the realm of the capital formation capabilities of the working interest owners. The message of these curves in exhibit 12 and of the table in exhibit 9 is that price alone will not solve the capital formation problem for the independent producers.

Gary Operating Co. has approached a number of its lending institutions in the Denver area to discuss the possibility of their advancing funds for the execution of an enhanced oil recovery project. It is their considered opinion that at the current status of the EOR technology, it is too high risk a project for them to advance the funds. We have also spoken with several national lending institutions, which have taken the same position.

As a result, Gary Operating Co. feels that the smaller independent will need some form of Federal economic incentive; and, as my exhibits illustrate, the economic incentive of price alone will not be sufficient. Without guaranteed loans the smaller independent will have to withdraw from the EOR area because of the capital formation problem. We, therefore, are in favor of Senate bill 2999.

I thank you very much.

[The prepared statement of Dr. Goldberg follows:]

July 17, 1978

TESTIMONY ON TERTIARY ENHANCED OIL RECOVERY
BEFORE THE SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES,
SUBCOMMITTEE ON ENERGY CONSERVATION AND REGULATION

PRESENTED BY:

Arnold Goldburg, Ph.D.
Manager of Enhanced Oil Recovery
Gary Operating Company

Michael J. Driver
Vice President & General Counsel
Gary Operating Company

Gary Operating Company
4 Inverness Court East
Englewood, Colorado 80112

INTRODUCTORY STATEMENT

My name is Arnold Goldburg and I am Manager of Enhanced Oil Recovery for Gary Operating Company, an independent oil producer, with properties in the Rocky Mountain area. In this position, I am also Project Manager of the Department of Energy Micellar-Polymer Demonstration Project in the Bell Creek Field, Montana. With me today is Michael Driver, Vice President & General Counsel of Gary Operating Company.

Gary Operating Company is a Colorado corporation formed on December 30, 1970. It employs approximately 275 employees and its corporate office is located in Englewood, Colorado. The Company's principal stockholder is Samuel Gary, an independent oil producer, who also serves as Chairman of the Board of Directors.

The Company evolved from the discovery and operation of the Bell Creek oil field located in southeastern Montana. The Bell Creek field was discovered in 1967 and is the 84th largest U. S. oil field. Today, Bell Creek has over 400

wells and the total daily production is approximately 20,000 barrels.

In 1975, Gary Operating Company was awarded a contract with the Department of Energy (formerly Energy Research and Development Administration) for the operation of a tertiary enhanced oil recovery pilot demonstration in the Bell Creek Field.

TERTIARY ENHANCED OIL RECOVERY: TECHNIQUES AND POTENTIAL

Enhanced Oil Recovery (EOR; also known as tertiary recovery) will be one of the major alternate energy resources until the end of the century. The reason for this is its attractive characteristics:

1. The infrastructure of oil field, pipelines and refineries are already in place; i.e., essentially no environmental impact.

2. The projected costs are relatively well known "in-hardware" numbers because the infrastructure is in place and the chemicals are now produced for other purposes.
3. EOR is a "soft technology" in that it can be deployed in an oil field in any magnitude - over 100 acres, 1,000 acres or 10,000 acres.
4. The location of the EOR target oil is known and its extent is large.

Typically, with today's technology, 70% of the oil remains in the ground, Exhibit 1. The tertiary oil blob is locked in the reservoir by high viscosity and/or high interfacial tension between the subterranean water and oil in the microscopic rock pore spaces of the oil reservoir, Exhibit 2. There are two basic, but complex in execution, approaches to mobilizing this tertiary oil: for high viscosity, heating (steam or in-situ combustion); and for high interfacial tension, chemical surfactants (detergents; i.e., washing the oil off the reservoir rock), and miscible carbon dioxide (i.e., leaching the oil out of the water/rock pore spaces), Exhibit 3.

Exhibit 4 is a schematic of how an enhanced oil recovery process works. In the Thermal EOR production processes, the displacing process fluid, numbered (1) in the schematic, is steam or a flame front and combustion gases. In the Chemical EOR production processes, the displacing fluid (1) is a surfactant agent or very high pressure carbon dioxide or nitrogen. Depending upon the individual reservoir characteristics, the displacing fluid and the "oil bank" which is being formed may require supporting and controlling drive fluids; these "mobility control" slugs are usually water thickened with polymer. They are used to maintain control of the mobilized oil bank. The mobility control fluid is numbered (2) in the schematic, Exhibit 4. Slug (2) in turn may have to be followed by an inexpensive driving fluid numbered (3), which is water.

As Exhibit 1 shows, there are approximately 300 billion barrels of remaining oil-in-place in the United States, including offshore and Alaska. This is the target for tertiary enhanced oil recovery technologies. It is estimated that 100 billion barrels of this target can be attacked with current EOR technology. Typical EOR laboratory results obtain 80%-90% of tertiary oil-in-place. Field test results are just now becoming available and indicate recoveries as high as 60%. Even at EOR efficiencies of 30%, production of tertiary oil reserves would equal one-third of all production to date in the U.S., 30 billion barrels. Exhibit 5 indicates the EOR impact in barrels per day in the year 2000. Current petroleum consumption in the United States is at the rate of approximately 18 million barrels per day. Enhanced oil recovery is a "Near" term technology, with energy impact equal to or at least half as great as any of the other advanced alternate energy resources.

The U. S. is presently importing over 8 million barrels of oil per day at a foreign trade deficit cost of approximately \$45 billion per year. It is projected that by 1990, EOR production could be 3 million barrels per day. This EOR production would directly displace that amount of imported oil and result in a corresponding cash outflow savings of more than \$50 million per day to the U. S. Leaders of foreign Governments are bringing great pressure to bear upon the President to stabilize the dollar value in international currency exchange. EOR is not a solution to the trade deficit problem, but it can make a significant contribution toward its resolution.

BELL CREEK MICELLAR-POLYMER PILOT DEMONSTRATION

Gary Operating Company is the operator of the Bell Creek Field with 240 million barrels of original oil in place. It is located in southeast Montana, and Samuel Gary Oil Producer is a 20% Working Interest Owner. Gary Operating Company is conducting a cost-sharing Department of Energy Micellar-Polymer

Oil Recovery Pilot Demonstration in Unit 'A' of the Bell Creek Field in order to help determine whether micellar-polymer chemical flooding is an economically feasible technique for enhanced oil recovery in a typical Rocky Mountain reservoir, Exhibit 6. The Bell Creek Field reservoir characteristics are ideally suited to the micellar-polymer technique, Exhibit 7. Exhibit 8 is the Time Line for the pilot project.

The cost of the 40-acre pilot project is \$5 million, which is shared on a 50/50 basis between DOE and the field owners. If the pilot is successful, expansion of the process to the full Unit 'A' reservoir could produce an additional 28 million barrels of tertiary oil, and an additional 55 million barrels, if applied to the full Bell Creek Field.

MAJOR OBSTACLE TO EOR PRODUCTION BY INDEPENDENTS:

CAPITAL FORMATION

To illustrate the front-end capital formation economics for EOR, the projected financial data for a full field micellar-polymer flood in Bell Creek Unit 'A' is given in Exhibit 9. (These numbers can be generalized to a base case reservoir of 10 million barrels original oil in place with primary plus secondary recoveries of any given percentage, see Exhibit 10). As Exhibit 9 reveals, in order to develop the reservoir for tertiary oil recovery, Bell Creek owners must spend \$140 million for injection chemicals--chemicals which must be pumped into the ground before oil is produced. For a small independent oil company, working with limited assets and using an unproven technology, this poses an insurmountable capital formation problem. (Of course, the tertiary project can be phased, and this approach is discussed below; however, phasing does not remove the capital formation problem.)

If independents are to produce the oil left in their fields after conventional primary and secondary recovery, they will need financial assistance. But so long as the EOR

techniques are still unproven, this assistance will not be forthcoming from traditional lending mechanisms. First generation EOR projects are considered too "high risk" for the financial institutions and their lending policies.

The risk inherent in an EOR project, before the technology has been proven extensively, is illustrated by Exhibit 11. This computer simulation, based on Bell Creek Unit 'A', calculates the probability of the owners receiving a given discounted cash flow rate of return on their investment. The uncertainties considered in this simulation include:

- Crude oil price (from \$15 to \$25)
- EOR recovery (35 percent to 55 percent)
- Chemical costs (linked to crude oil price)
- Operating costs
- Capital costs

As Exhibit 11 shows, the owners have a 50 percent chance of receiving a 15 percent rate of return. But, with a high-risk project such as an early EOR effort, prudent investors would look for a rate of return well in excess of 15 percent--probably over 25 percent. As Exhibit 11 shows, the probability of this rate of return is only about one chance in 100--not sufficient to attract venture capital.

Government incentives must assist independents in providing mechanisms to obtain the required front-end capital and in proving EOR technologies for full scale application. Exhibit 12 examines some possible approaches and their implications for Bell Creek Unit 'A'. This exhibit displays the cumulative net cash flows after tax for a full field flood with three different financial incentives: (A) a guaranteed oil price of \$17/barrel, with no financing aid; (B) a guaranteed price of \$17/barrel with 90 percent guaranteed loans; and (C) a guaranteed price of \$25/barrel with no financing aid. The chemical costs are capitalized and are not escalated, but are based on current costs. In this regard, cash flows of Exhibit 12 are optimistic,

as chemical costs will certainly rise. These cash flows are for a phased recovery representing a production/logistics strategy of maintaining constant chemical fluid injection rates in order to optimize the balance between operating costs and capital investment. The resulting time schedule is consistent with that projected by DOE for micellar-polymer floods.

For the cases presented above, the maximum negative cumulative net cash flows after tax (MNCNCFAT) are respectively:

<u>Incentive Cases</u>	<u>(MNCNCFAT)</u>
Case A) \$17/bbl. no financing	(\$45 million)
Case B) \$17/bbl. 90 percent financing	(\$ 6 million)
Case C) \$25/bbl. no financing	(\$35 million)

With the exception of Case B, the capital formation problem for a micellar-polymer flood is far beyond the financial resources of the independent owners of the Bell Creek field. The same would naturally be true for any individually-owned property, Exhibit 10.

Gary Operating Company has met with several Denver-based financial institutions with whom Gary Operating Company has historically arranged financing. Given the unproven and high risk nature of early EOR projects, none of the traditional lending sources will provide the necessary front-end capital for a deployment of a micellar flood in Unit 'A'. Further, Gary Operating Company has met also met with several large national financial institutions which have taken positions similar to those of the Denver banks.

Thus, to stimulate maximum EOR investment and recovery, in a timely manner, government financial incentives will be needed. Gary Operating Company favors a price of at least \$17 per barrel for EOR crude plus a guaranteed loan program such as presently provided for by the Geothermal Energy Research, Development and Demonstration Act of 1974. Therefore, Gary Operating Company favors Senate Bill 2999 as recently introduced

by Senators Gary Hart (D-CO), Floyd Haskell (D-CO), Pete Domenici (R-NM) and Charles Percy (R-IL). As shown in Exhibit 12, the combination of price incentives and guaranteed loans, as proposed by this bill, would make first generation high-risk EOR projects feasible for independent oil companies. Additionally, tax incentives could enhance the desirability of venture capital investment in EOR projects.

INDEPENDENT OIL PRODUCERS: THE RISK TAKER, THE INNOVATOR

The independent oil producer is responsible for approximately 40% of the oil production and by inference 40% of the reserves in the U. S., and also for approximately 80% of the domestic wildcats presently drilled. As shown above, the front-end costs for tertiary enhanced oil recovery (chemical) projects exceeds the independents' ability to accomplish the required capital formation by about a factor of 5 to 10. Tertiary enhanced oil recovery (chemical) projects must be viewed not as advanced waterflood production, but in the same category as other exotic energy replacement resources such as shale, synfuels, and geothermal.

If the independents are to participate in EOR at all, and if they are to play their traditional innovative role in the oil industry, then financial incentives must be provided for them for the first generation EOR full field recoveries. Exhibit 12 indicates the relative effectiveness of the guaranteed loans in dealing with the capital formation problem. Further, this particular mechanism brings the traditional lender-borrower relationship into play at the very beginning of this new EOR technology. When the lender has confidence based upon field experience and recovery results, the hidden arm of the Government may withdraw, leaving the complete technology/financing infrastructure in continued operation.

The independent oil man is by nature a risk taker. Without loan guarantees, he would probably divert his available capital

from recovery of EOR reserves to drilling wildcats; and thus, leave unrecovered, known proven EOR reserves. Further, it is likely that the incremental domestic oil recovered from wildcat drilling per incremental dollar invested should be considerably less than the incremental domestic oil recovered per incremental dollar invested in EOR.

Another suggested EOR incentive is the release from price controls of any crude oil produced from a property where any qualifying tertiary process is being utilized, as is suggested in S. 2623 introduced by Senator Bentsen. For many potential EOR projects, this bill would be sufficient to assist in the necessary formation of capital. However, this is not the case for the Bell Creek pilot because by the date of enactment of this bill (assuming passage), the remaining secondary reserves in Bell Creek would be sufficiently small that insufficient capital relative to EOR requirements would be generated by the receipt of world market price for the remaining secondary production. Further, for those properties in which the secondary flood has been completed, the Bentsen approach provides no incentive. For the property that is still in the primary or early secondary recovery stage, the Bentsen approach is a good incentive and may assist both independents and major companies in obtaining capital from financial institutions. For Bell Creek and many other independents, however, loan guarantees are the best solution to the capital formation problem.

As can be seen from the exhibits discussed above, if sufficient front end capital (\$140 million in Bell Creek Unit 'A') can be raised; and if the independent operator can be insulated, to some extent, from a large negative cash flow (\$48 million in the eighth year of the Bell Creek Unit 'A' flood), independents should be able to successfully commercialize EOR floods. Without such aid, the independents will have to default their EOR recovery potential to the larger operators.

REGULATORY CONCERNS: INCREMENTAL OIL AND COMPOSITE PRICE

Many owners and operators have expressed concern over such DOE concepts as "incremental oil" and "composite price". Qualifying an enhanced tertiary oil recovery project for a given oil field should be within the jurisdiction of the State regulatory agencies, as suggested in DOE's proposed rulemaking issued on January 17, 1977. Once qualified and capital expenditures for each phase are committed, oil recovered thereafter should be priced in the same manner as stripper wells are presently priced.

The regulation language will have to be written to apply to qualified EOR projects, where a project may involve only a part of a reservoir. As indicated above, the optimal deployment strategy for the Bell Creek Unit 'A' reservoir consists of three sequential phases, i.e., three sequential EOR projects in the same reservoir.

The EOR oil which receives the incentive price should either be excluded from the composite price or the composite price should be adjusted upward accordingly.

FAIRNESS TO THE CONSUMER AND COST TO THE U.S. TREASURY

A thorough analysis of consumer impact and cost to the U.S. Treasury is beyond the scope of this testimony. However, Gary Operating Company would be pleased to have the opportunity to work with the Committee in developing this data, and to the extent that the Bell Creek EOR pilot project and the full field economics developed therefrom could be useful as data base in addressing these concerns, Gary Operating Company would make this data available to the Committee and its staff.

CONCLUSION

Based on the Bell Creek EOR pilot project, it is the recommendation of the Gary Operating Company that the most

important federal incentive to the smaller operator is the loan guarantee provision contained in the Hart Bill (S.2999). The release of the ceiling prices on secondary crude would be very helpful, but the sufficiency of this assistance is directly tied to the barrels of secondary reserves remaining. Another incentive which might be explored--perhaps more appropriately by Senate Finance, is favorable tax treatment for EOR projects. Should additional information be helpful in this regard, Gary Operating Company is prepared to submit its thoughts on tax incentives.

Should the Committee or staff have any questions regarding this presentation, Dr. Goldburg and Mr. Driver will respond accordingly.

EXHIBITS

- 1 Target for Tertiary Enhanced Oil Recovery
- 2 Oil Blob (Ganglia) Schematic
- 3 Oil Mobilizing Mechanisms: Thermal and Surfactant
- 4 Enhanced Oil Recovery Process Schematic
- 5 Prospects Alternate Energy Resources
- 6 Bell Creek Unit 'A' Waterflood and EOR Pilot Location
- 7 EOR (Chemical) Preferred Characteristics
- 8 Bell Creek EOR Pilot Time Line
- 9 Projected Financial Data, Bell Creek Unit 'A' Full Field Micellar Flood
- 10 Projected Financial Data, Base Case Reservoir 10 Million Barrels Original Oil in Place. Full Field Micellar Flood
- 11 Risk/Reward Probabilities
Bell Creek Unit 'A' Micellar Flood
- 12 Cumulative Net Cash Flow
Bell Creek Unit 'A' Micellar Flood

"TOTAL USA" (Incl. OS & AI) ERDA

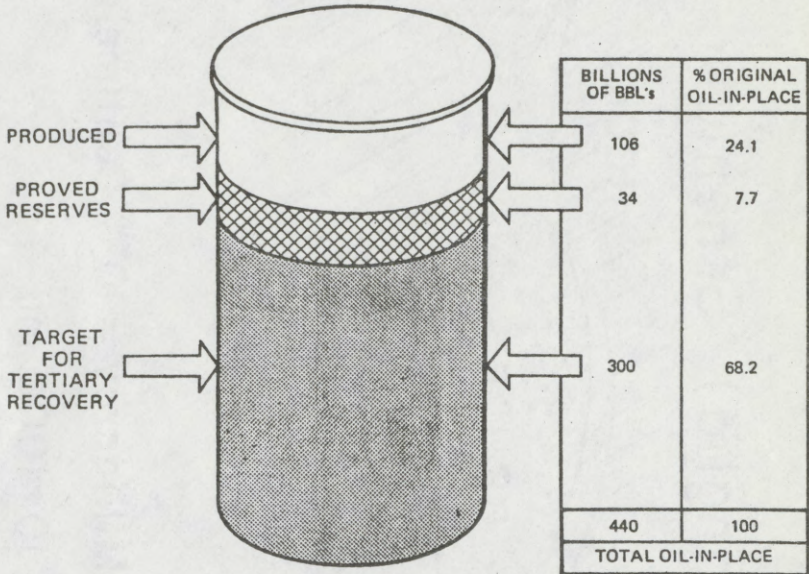
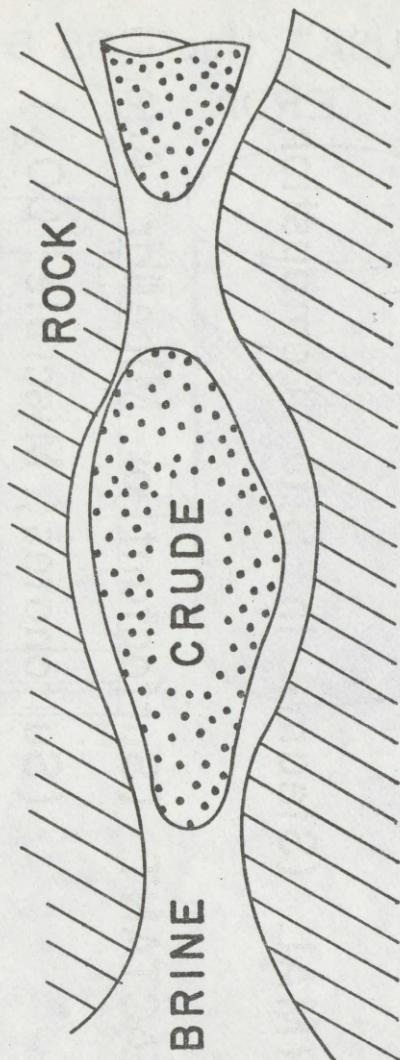


EXHIBIT 1

BLOB (Ganglia) Schematic



Permeability: 1 Millidarcy = 10⁻¹⁸ Centimeters²

Oil Reservoir: 10-1000 md

EXHIBIT 3

MOBILIZING MECHANISMS

μ : THERMAL (Steam; In - Situ Combustion)

σ : SURFACTANT (Surfactant or Micellar Agent)
(Sulfonates, Miscible CO₂)

ENHANCED OIL RECOVERY SCHEMATIC

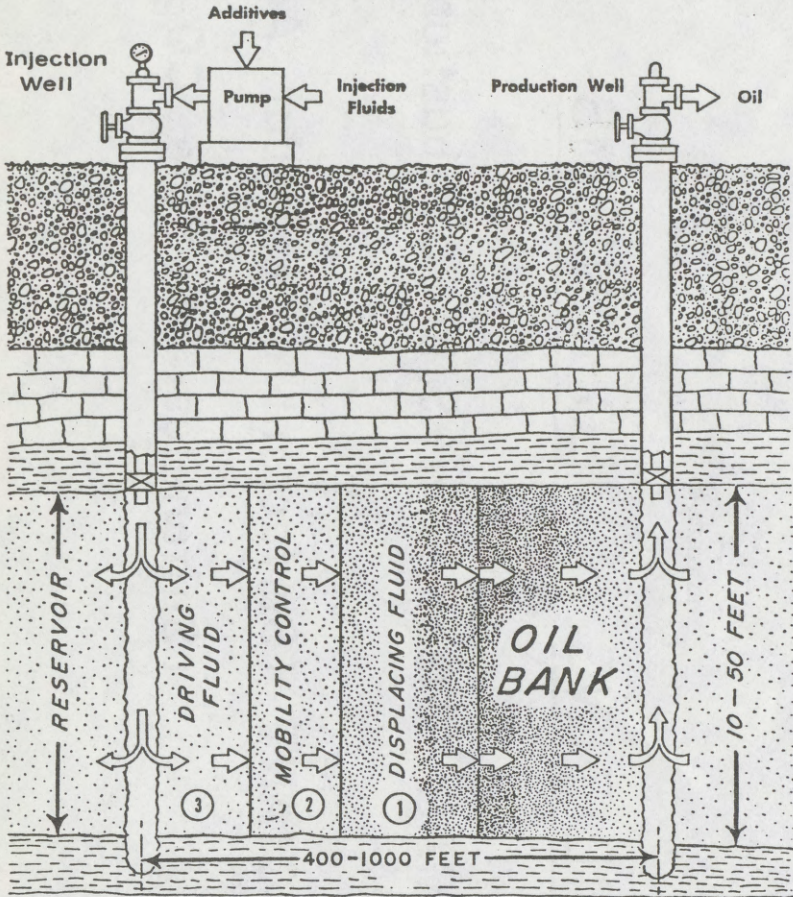


EXHIBIT 4

PROSPECTS

ALTERNATE ENERGY RESOURCES

TECHNOLOGY	TERM	INFRA- STRUCTURE	IMPACT IN YEAR 2000 MILLION EQUIVALENT Bbls / Day
EOR	Near	Yes	5
Coal Direct	Near	No	12
Nuclear	Near	No	14
Geothermal	Mid	No	2
Shale	Mid	No	3
Coal Syn Fuel	Mid	No	7
Solar/Breeder/Fusion	Long	No	3

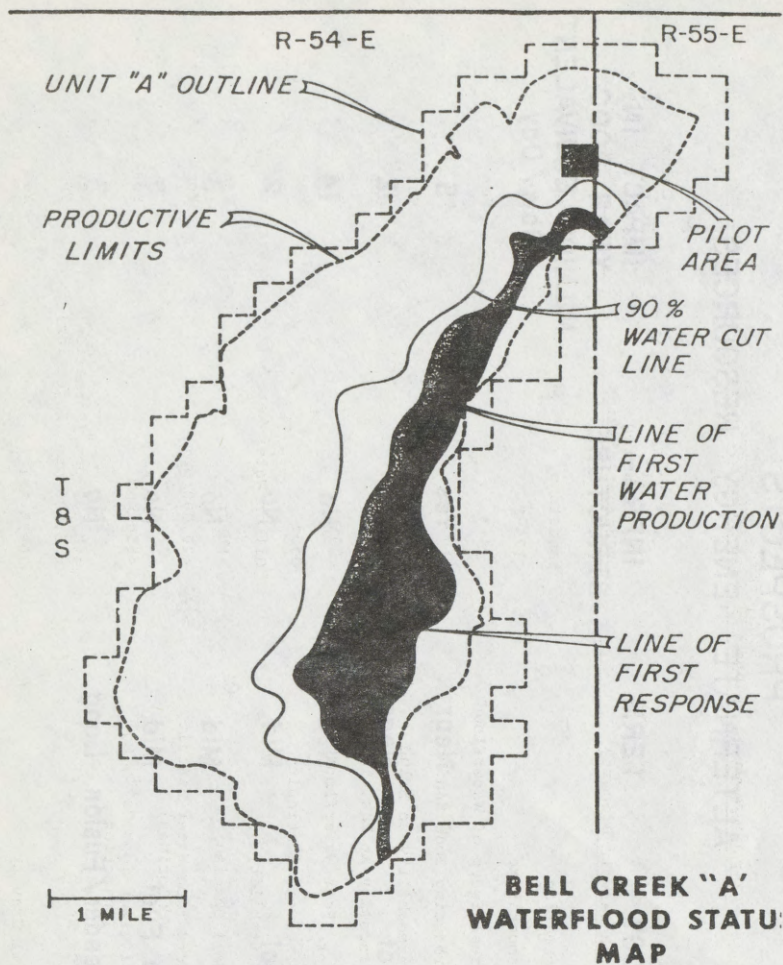


EXHIBIT 6

EXHIBIT 7

BELL CREEK 'A' MUDDY SAND UNIT
SITE CONFORMANCE TO PREFERRED CHARACTERISTICS FOR MICELLAR-POLYMER FLOODING

	Reservoir Property	Column 1 RFP Preferred Characteristics	Column 2 Bell Creek Unit 'A' Site Meets or Exceeds Column 1
1.	Formation	Sandstone	Yes
2.	Temperature	<175°F	Yes
3.	Areal Sweep of Waterflood	>50%	Yes
4.	Producing Zone Sand	>10 ft.	No (Yes) *
5.	Permeability to Brine	>10 md.	Yes
6.	Viscosity at Res. Temperature	<20 cp	Yes
7.	S _{or} (Post Waterflood)	>30%	Yes
8.	Reservoir Continuity	Good	Yes
9.	Wettability	Oil or Water Wet	---
10.	Well Spacing	>10 ft.	Yes
11.	Formation Water Salinity (Chlorides)	<20,000 ppm	Yes
12.	Divalent Ions Ca ⁺⁺ , Mg ⁺⁺ (Injection)	<500 ppm	Yes
13.	TDS Water	<50,000 ppm (Formation) < 5,000 ppm (Injection)	Yes Yes
14.	Oil Gravity	20-35 API	Yes

* pilot area (full field Unit 'A' average net pay is 11.9 feet)

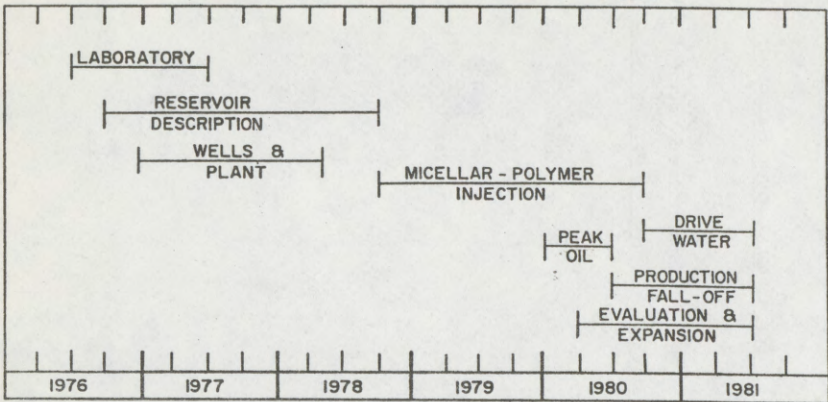
TIME LINE - BELL CREEK PILOT

EXHIBIT 8

EXHIBIT 9
PROJECTED FINANCIAL DATA
MICELLAR-POLYMER FLOOD
BELL CREEK UNIT 'A'

Original Oil in Place (OOIP)	122 million barrels
Primary Plus Secondary Production*	58 million barrels (estimated)
Net Worth of Production**	\$230 million
Net Worth of Production After Taxes (assume half)	\$115 million
Available Capital for Tertiary Target (assume 10% Net Worth After Tax)	\$ 12 million
Available Tertiary Target	64 million barrels
Expected Tertiary Recovery	28 million barrels
Chemical Costs for Tertiary Target (\$5 per Tertiary Barrel; as per Pilot)	\$140 million
<u>Capital Formation Problem</u>	<u>(\$128 million)</u>

* 49 million barrels (12-31-77)

** Net Value of Production Less the Value of the Capital Investment, the Operating Costs and the State Production Taxes, all over the primary plus secondary production lifetime. Federal and State Income Taxes have not been deducted.

EXHIBIT 10
FINANCIAL DATA
MISCELLAR-POLYMER FLOOD
BASE CASE
ORIGINAL OIL IN PLACE
10,000,000 BARRELS

	<u>PRIMARY PLUS SECONDARY PRODUCTION</u>	
	<u>20% or 2 Million bbls.</u>	<u>40% of 4 Million bbls.</u>
Net Worth of Production (\$4/bbl. old oil)*	\$8.0 million	\$16.0 million
Net Worth of Production After Taxes (assume half)	\$4.0 million	\$ 8.0 million
Available Capital for Tertiary Target (assume 10% Net Worth After Taxes)	\$0.4 million	\$ 0.8 million
Available Tertiary Target	8 million bbls.	6 million bbls.
Expected Tertiary Recovery (half)	4 million bbls.	3 million bbls.
Chemical Cost for Tertiary Target (\$5-\$10/Tertiary bbl.)	\$20-\$40 million	\$15-\$30 million
Capital Formatin Problem per 10 million bbl. OOIP	(\$19-\$39 million)	(\$14-\$29 million)

* Average over a 10-15 year production lifetime to date.

MICELLAR FLOOD BELL CREEK UNIT 'A'

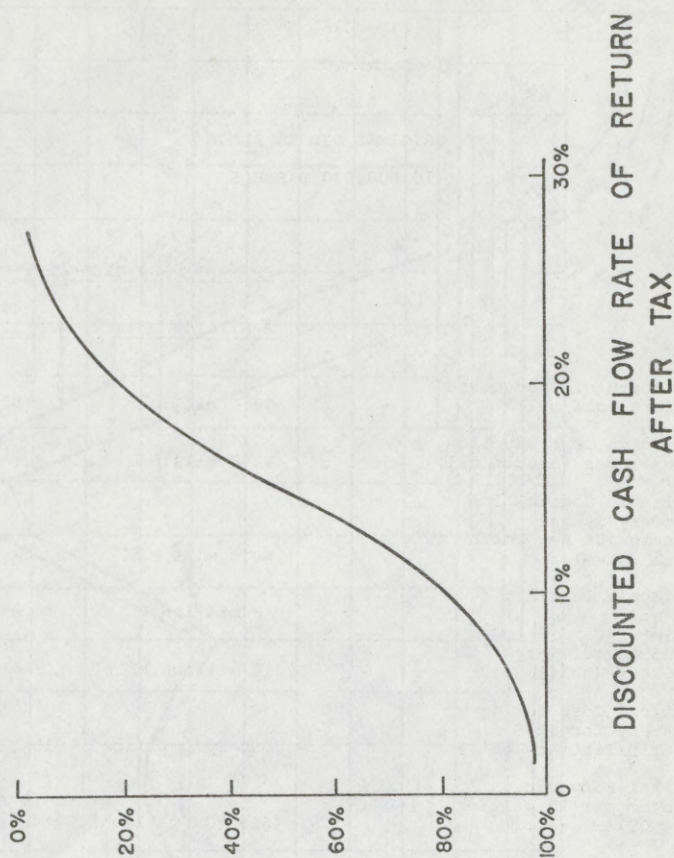
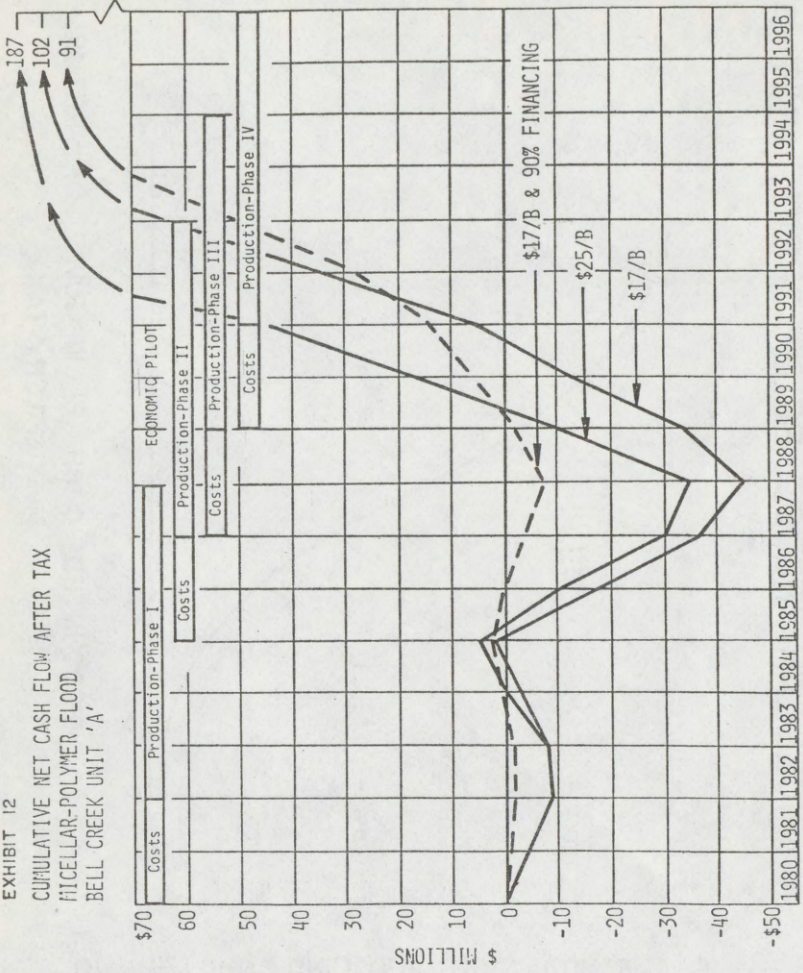


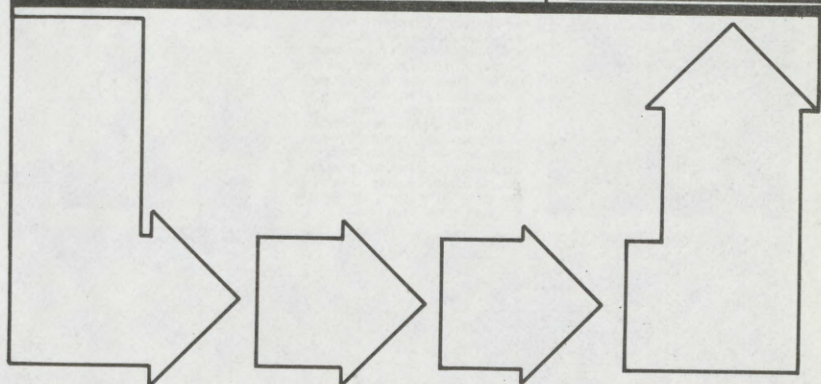
EXHIBIT II

EXHIBIT 12

CUMULATIVE NET CASH FLOW AFTER TAX
MICELLAR-POLYMER FLOOD
BELL CREEK UNIT 'A'



ENHANCED OIL RECOVERY

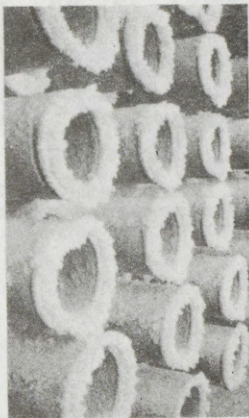


Leftover Oil



In 1967, wildcat drilling operations struck a rich oil reservoir under the rolling plains of southeastern Montana. Named the Bell Creek field, it had 240 million barrels of original oil in place. However, engineering predictions soon indicated that by the late 1970s production from this field would rapidly decline—leaving more than half of the original oil locked in the reservoir. Faced with this dilemma, Samuel Gary, Oil Producer, a co-owner of the field, and the Gary Operating Company, operator of the field, began searching for new ways to unlock the remaining oil. This search led to Enhanced Oil Recovery technologies—methods which may recover another 55 million barrels of oil from the Bell Creek field and which may produce another 50 billion barrels of oil for the nation at large.

Enhanced Oil Recovery represents an important part of the future for Gary—and for the nation. To help explain the problems, the potential and the possible energy future of Enhanced Oil Recovery technologies, this booklet has been prepared.



EXECUTIVE SUMMARY

Enhanced Oil Recovery: Potentials and Opportunities

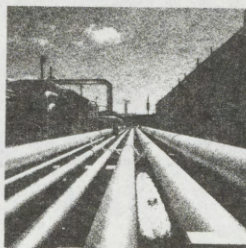
A "New" Domestic Oil Source For the United States

The story is painfully familiar: the jolt of the Arab oil embargo, followed by winters of too much cold and too little energy; the sudden, bitter fights over development of the nation's remaining energy supplies; Congressional struggles to produce a workable energy program; and the domestic economy staggering under the weight of vast sums spent for foreign oil. The potential solutions are also familiar: the often-discussed technologies of oil shale and coal gasification; the vast potential of new energy sources such as solar and nuclear fusion; and the possibility of new, legislatively-mandated conservation measures.

At the heart of today's energy crisis debates, one crucial question stands out: Is there an economic and environmentally-effective technology to help the nation in the next few decades? For, the problem is already here—while most of the solutions are still somewhere in the future. Two obvious answers to the immediate problem are coal and conservation. Another less well-known, but perhaps equally important, answer is Enhanced Oil Recovery.

Enhanced Oil Recovery (EOR) refers to the technologies needed to unlock vast supplies of oil remaining in the nation's known oil reservoirs. This oil, often called tertiary oil, remains in the ground after the conventional techniques of primary and secondary production have withdrawn all they can. Together, these two conventional production stages recover only about one-third of all the oil in a given reservoir. The remainder—estimated at 300 billion barrels for the entire nation—stays locked in the porous underground rock formations.

This cache of domestic oil is not a new discovery. For the past 50 years, petroleum researchers have sought ways to produce tertiary oil. But, with the plentiful, inexpensive sources of primary and secondary crude in the U.S. and abroad, this research remained in the laboratory.



In 1973, however, the Arab oil embargo jolted the United States out of its energy complacency—and new energy resources and technologies began to be vigorously pursued. For the past several years, petroleum researchers have seriously evaluated EOR techniques and have brought several into the field testing stage. Some researchers believe these methods may eventually contribute as much as 50 billion barrels of oil to U.S. energy supplies.

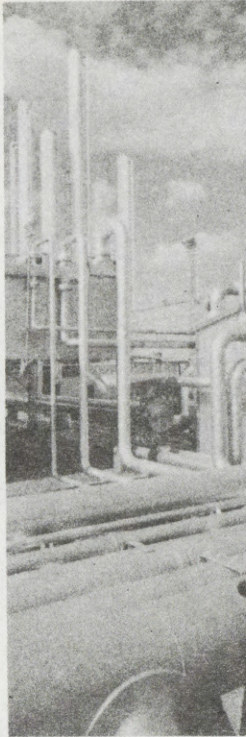
Like all new alternate energy technologies, EOR methods face serious uncertainties. The EOR technologies are still relatively new and petroleum researchers are not yet certain how well they will work in the field. But, in comparison to other exotic technologies, EOR methods also have a very strong plus side. First, the infrastructure for implementation is already in place. EOR will use the same pipelines, refineries and almost all of the same wells as were used for primary and secondary recovery. Plus, the special chemical materials needed for EOR processes are already in commercial production for other uses. Thus, the estimated costs for EOR production are based on current costs for existing materials—giving fairly solid, reliable numbers as opposed to the uncertain, and inevitably underestimated, "paper" numbers of other exotic energy technologies.

Research to date shows that the environmental impacts of EOR technologies will be minimal, essentially no more than is experienced with primary and secondary production. And, EOR development would not have the boom-bust cycles of many other exotics. In fact, EOR will keep existing oil fields, with their jobs and communities, open—and producing oil. The Congress' Office of Technology Assessment predicts that by 1990, EOR technologies may be producing one billion barrels of oil per year; by 2000 this figure may rise to two billion barrels per year.

**High-Risk, High-Cost Technologies:
A Potential in Billions of Barrels**

Even with this strong plus side, the first generation EOR projects will still involve high financial risks. And EOR technologies, like other exotic energy technologies, require extremely high front-end costs. This is especially true for the high-potential techniques which use chemicals to wash the oil out of reservoirs. For example, it is estimated that the front-end chemical costs for an EOR chemical project producing three million barrels of oil will be \$15-30 million. And these chemicals must be pumped into the ground anywhere from 1 to 2 years before the project starts producing significant amounts of oil.

These massive front-end costs, and the long time lag to production, may close the door to many would-be EOR competitors, especially the smaller independent oil companies, which are known as the oil industry's risk-takers and innovators. These companies, controlling an estimated 40 percent of the nation's oil reserves, simply do not have the financial resources to fund such projects. And, without some financial incentives they cannot join in the race to get EOR processes on stream and producing oil for the country.



A number of federal financial incentives have been suggested for EOR projects. Most of these incentives, however, do not address the major problem of the independents—front-end costs. To keep the EOR business open to all potential EOR producers, a combination of guaranteed loans and price guarantees is suggested. With guaranteed loans, independent oil companies could get the financing they need to pursue EOR projects, while price guarantees provide financial incentive for these high-risk projects.

A workable combination of loan and price guarantees is: a 90 percent guaranteed loan, and a price guarantee of at least \$17 per barrel. With this combination, a successful EOR project could net its operators a reasonable rate of return while netting the nation additional energy that would otherwise stay locked in the ground.

Of course, EOR projects will not always be high risk. Over time they will become conventional technologies requiring no special incentives. But, to get these projects started, financial incentives are needed. And, the incentives that draw the greatest number of competitors to the EOR arena will help net the greatest amount of energy for the nation as quickly, and as cheaply, as possible.

Leftover Oil

300 Billion Barrels Left in the Reservoir

Beneath the surface of the United States, billions of barrels of oil lie locked in vast underground formations. This oil is not a major new discovery. Nor is it hidden in still unexplored reservoirs. Rather it has been left behind in the same reservoirs that have supplied U.S. domestic oil production for the past century.

This is tertiary oil, the oil that remains in underground reservoirs after conventional technologies have withdrawn all that they can. Today, this leftover oil offers "new" energy—a vast store of petroleum which may help the United States weather the next few energy-short decades. Unlocking this store of oil, however, will not be easy.

The leftover oil remains locked in underground reservoirs because of the complex nature and interactions of the oil and water in these formations. An oil reservoir is not simply an underground lake of oil that, once tapped, can be easily and fully depleted. Instead, the term refers to oil locked in porous sedimentary rocks. These rock and oil combinations first formed beneath the waters of prehistoric lakes and in following eons were overlain by formations impervious to oil. In these reservoirs, the oil, usually mixed with water, is trapped in microscopic open spaces between the grains of sedimentary rocks, much as water is trapped in a sponge.

To withdraw oil from the underground reservoir, the first step is primary recovery, which relies on natural forces to help push some of the oil out of the earth. In secondary recovery, water is injected into the ground to augment the natural forces. On the average, these two recovery methods together withdraw approximately one-third of the original oil in place. The remainder—two-thirds of all the oil—stays locked in the rocks. As shown in Figure 1, this two-thirds adds up to approximately 300 billion barrels of oil—the target of EOR technologies.



Cheap, Plentiful Crude Overshadows EOR Research

This leftover oil is not a newly-discovered phenomenon. For the past half century, researchers have sought ways to tap it. The first flurry of research came in the late 1920s and early 1930s. But, these early efforts disappeared in the flood of plentiful, conventionally-produced crude. In 1957, the Suez Canal crisis, and the accompanying fears of an oil cutoff, re-opened efforts to produce the leftover oil. Once again, the efforts were doomed due to the steady flow of inexpensive imported primary and secondary crude.

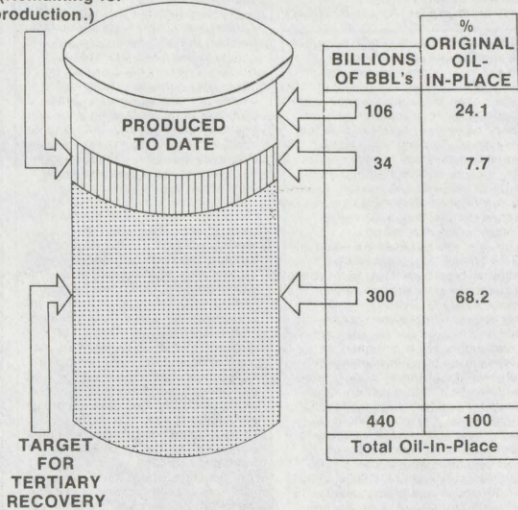
The 1970s, of course, changed all this with the frightening combination of an Arab oil embargo, declining domestic production and rising domestic consumption. Today, the United States energy scenario looks grimmer than ever. Domestic oil production has declined steadily, from a peak of 9.6 million barrels a day in 1970 to 8.2 million barrels a day in 1977. The nation now consumes over 18 million barrels a day. And every month we spend \$4 billion for imported oil. Crude oil flowing from Alaska's Prudhoe Bay has increased domestic production, but only temporarily. The overall trend remains downhill. And, the hope for major new discoveries grows smaller every day. The nation's known producible oil reserves have declined by two to five percent per year since 1970. Over the past two decades, new oil discoveries have been minimal. In fact, Bell Creek, discovered in 1967 and the 84th largest field in the U.S., represents one of the last major domestic oil discoveries.

This gloomy picture has naturally sparked a good deal of interest in the oil remaining in underground reservoirs. And the number of Enhanced Oil Recovery (EOR) research projects, seeking ways to produce the leftover oil, have multiplied. Of the 300 billion barrels believed to remain in oil reservoirs, research indicates that EOR methods might eventually recover anywhere from 15 billion barrels to 50 billion barrels.

But the total amount of EOR-produced oil may not be as critical as the relative speed with which EOR methods start producing significant amounts of oil. The real need for this oil comes in the next few decades, as the domestic oil produced by conventional technologies continues to dwindle—from the current 8 million barrels a day to an expected 7.5 million barrels a day in 1980 to a possible low of 4.2 million barrels a day in 1990. Other exotic energy technologies are not expected to make significant contributions within the near future. So, the need for the leftover oil is most critical in the next few decades. And the race to find workable, economic ways to produce this oil is on.

"TOTAL USA" (Including Offshore and Alaska)

PROVED RESERVES
(Remaining for production.)



DOE 1977

Figure 1—Total USA Oil Resources: Proven US oil resources, including offshore and Alaskan reservoirs, add up to 440 billion barrels of oil. Of that oil, nearly 300 billion barrels will remain in the ground after primary and secondary production. Of this 300 billion barrels, EOR methods may produce another 50 billion barrels of oil for the nation.

Tapping the Leftover Oil

A Variety of Approaches From Steam to Chemicals to Microwave

For the past five decades, researchers have sought ways to tap the tertiary oil in underground reservoirs. The task of coaxing this oil out of the porous reservoir rock, however, is not simple. First the new processes and technologies must be applied, tested and refined. To complicate matters, oil reservoirs are not all the same—they differ in type of rock, depth, pattern, crude oil properties, temperature, etc. Thus, different technologies are needed to tap the leftover oil in different kinds of reservoirs.

To date, researchers have come up with a number of Enhanced Oil Recovery processes. Most of these are still in the field testing and/or laboratory stage. Only one—steam injection—is in significant commercial use.

Steam injection is a thermal process, used to tap reservoirs with highly-viscous, or thick, slow-flowing oil. When heat, introduced by steam injection or underground combustion, is applied to this highly-viscous oil, the oil thins and flows more easily to producing wells. Steam injection processes have been in use in California since the mid-1960s. In fact, this method currently accounts for 16 percent of the state's oil production.

Some reservoirs, however, are not well suited to steam injection technology. To tap the crude found in these reservoirs, other more exotic EOR technologies are required. The best known of these are the miscible processes, in which fluids that mix easily with oil are injected into reservoirs. As the fluid passes through the reservoir, the oil dissolves in it. This forms a single oil-like mixture, or oil bank, that can flow through the reservoir to the producing wells. The best known, and most widely-tested

fluid for miscible processes is carbon dioxide.

At first glance the CO₂ miscible process sounds quite simple. In fact, a number of EOR projects are concentrating on this technique. Notably, one very large project in Texas now produces nearly 40,000 barrels per day. However, in practice, problems in understanding the mixing relationships of the CO₂ with reservoir crude and in getting the CO₂ to sweep efficiently throughout the reservoir have slowed the widespread application of this technique.

A third type of EOR method is a chemical process, using different types of chemicals to tap the underground oil. These chemicals, explains Dr. Todd Doscher, a professor at the University of Southern California (USC) and a well-known EOR consultant, work "essentially like a soap" washing oil off the rock much as a detergent might wash oil off clothing. The chemical methods are the newest and the most complex of EOR processes—but a growing number of government and industry experts also say they have the greatest potential. According to some, the chemical methods could be responsible for about half of all EOR oil production by 1985.

In the chemical "surfactant/polymer," or "micellar/polymer," methods, the detergent-like chemical is mixed with either water or oil and injected into the reservoir. Dr. Arnold Goldberg, Manager of EOR for Gary Operating Company, an independent oil producer based in Englewood, Colorado, explains that "in a reservoir, the chemical lowers the interfacial tension between the oil and water locked in the rock. The oil is then allowed to move and coalesce into an oil bank." The oil bank flows to producing wells in front of the micellar slug which, in turn, is pushed in piston-link motion by polymer-

thickened water. (See Figure 2) In these chemical processes, the expensive chemical slugs, precisely designed to meet the chemical peculiarities of different reservoirs, are absorbed on the rock.

The miscible and chemical processes are by far the best-known exotic EOR methods—and the most likely to produce significant amounts of oil in coming decades. Several other EOR processes are also being developed—such as microwave and other electromagnetic techniques. Yet, these other EOR processes are not expected to have significant impact.

OPEC Pushes EOR Out of the Lab, Into the Field

Although basic research with EOR processes continued since the 1920s, it wasn't until after the Arab oil embargo, and skyrocketing oil prices, that the experimental efforts expanded to a serious scale. With the dawning realization of an energy crisis, EOR research projects suddenly sprouted across the United States. Today, the U.S. government, through the Department of Energy (DOE), provides partial funding for over 20 EOR projects, including seven micellar/polymer projects and four CO₂ miscible projects. The total tab for these projects is expected to reach \$180 million, with the government picking up about one-third, and industry cost-sharing the remainder.

For the future, says George Stousur, Chief of the EOR Branch in DOE's Division of Oil, Gas and Shale Technology, the government will add more EOR projects to its funding list. In fact, he reports, "DOE expects to add eight to 10 field tests in 1978." Of course, the energy industry is also conducting numerous EOR tests of its own across the United States.

One typical government/industry

EOR research project is found at the Bell Creek Field, located in the rolling plains of southeastern Montana. (See Figures 3 and 4) In 1967, the field was discovered with 240 million barrels of original oil in place. Samuel Gary, Oil Producer, has a 20 percent interest in the field and Gary Operating Company acts as operator of the field. By the early 1970s, it was apparent that when both primary and secondary production of the field were complete more than half the oil would remain in the ground. Gary and his partners began considering ways to produce this leftover oil, and the Bell Creek EOR project was born. Today, Gary Operating Company is conducting a Department of Energy (DOE) Technical Pilot Demonstration on 40 acres of Unit A of the field. The \$5 million project, which follows secondary waterflood production in the field (see Figure 4), is funded half-and-half by DOE and the field operators.

According to Dr. Goldberg, the Bell Creek project will use an oil-external micellar/polymer process designed by the Union Oil Research Center. The process chemical, an oil derivative, will be mixed with an oil base before being injected into the ground. With this mixture, the total process should require about one barrel of oil to every 10 produced.

The selection of this process for the Bell Creek field was determined through a rigorous selection technology, first successfully demonstrated in the Bell Creek Pilot Program. As Goldberg explains, the selection process started when reservoir characteristics—such as temperature, rock type and oil viscosity—were passed through an industry-developed technical EOR sorting screen. In a choice between miscible CO_2 , thermal and micellar/polymer processes, the screen pointed to the micellar/polymer technique as the most applicable for Bell Creek.

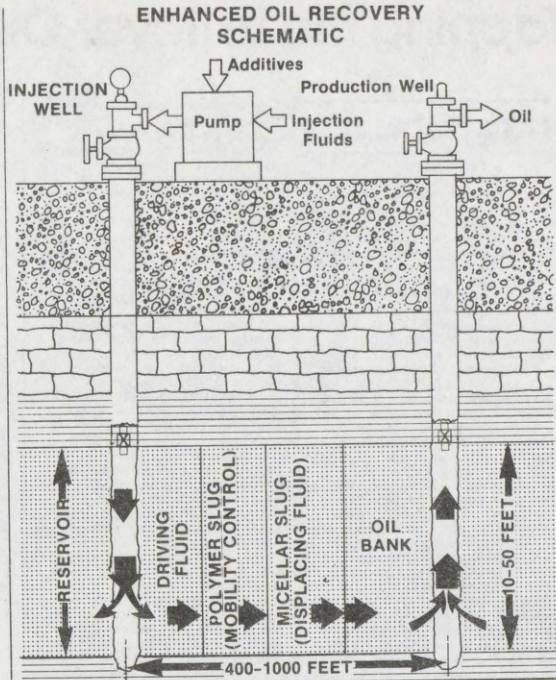


Figure 2—Enhanced Oil Recovery Schematic: To produce the leftover oil, some EOR processes first inject chemicals into the ground. These chemicals loosen the oil from porous reservoir rock while a driving fluid, usually a polymer-thickened water, pushes the oil bank to producing wells.

Tapping the Leftover Oil

Next Gary employed its rigorous selection methodology to determine which of two optimal designs would be most cost effective. For the Bell Creek field, an oil-external process was shown to be preferable.

Injection of chemicals into Unit A of the Bell Creek field begins in the last half of 1978. And, Goldberg says, "We should know if our pilot is successful by early 1980." (See Figure 5) The results, he adds, should be applicable to other micellar/polymer projects, for Bell Creek is well-suited to the micellar/polymer process and it is a typical Rocky Mountain reservoir. If the Bell Creek pilot is successful, expansion to the full Unit A reservoir could produce 28 million barrels of oil, while expansion to the entire field could add 55 million barrels to the oil already produced from Bell Creek. But, Bell Creek, like all EOR research projects, faces enormous uncertainties. And no one can know for sure how well the methods will work until several projects like Bell Creek have been completed.

Questions, From the Basic To the Complex

The uncertainties facing EOR projects range from the most basic questions about the oil reservoirs themselves to specific questions about the workings of the different EOR technologies. As L. Wally Holm of Union Oil Research Center notes, researchers generally have only limited information on reservoirs.

"While a producer may have spot information on the reservoir's characteristics at each well," he explains, "there exists no foolproof way of knowing what the reservoir is like between wells. As a result, we start off not knowing very much about the interior of the oil reservoirs themselves; and, therefore, we cannot be

TERTIARY PILOT STUDY AREA NORTH EAST CORNER BELL CREEK 'A' MUDDY SAND UNIT CARTER & POWDER RIVER COUNTIES, MONTANA

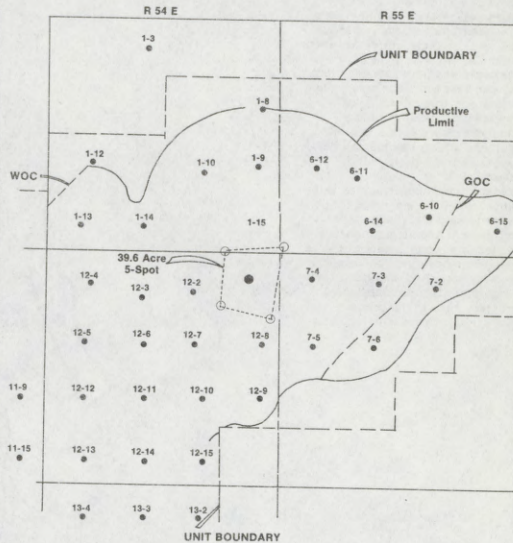


Figure 3—Bell Creek Unit A: The 40-Acre Bell Creek pilot, using a traditional five-spot well pattern, is found near the northeast tip of the field's Unit A.

Tapping the Leftover Oil

certain how much oil is actually left in the underground formations nor how non-uniform that formation is. So naturally we are uncertain as to how much tertiary oil is potentially recoverable by EOR methods."

"A reservoir's anatomy is the most important, but the least known aspect of field operations," Ted Geffen, a research consultant with Amoco Production Company recently told an EOR seminar. Indeed, the native variations in an underground reservoir can make or break an EOR project. For example, the pore spaces holding the oil can vary greatly in size, calling for larger or smaller portions of injected chemicals. And, natural fissures in a reservoir can ruin the project by allowing the injected fluid to bypass large portions of the reservoir.

Adding to these uncertainties is the fact that there exist few reliable or well understood field test results for either the miscible or chemical processes—so at present no one is sure of the quantitative recovery efficiencies of these processes. And analyses of low and high performance cases show that a small reduction in the process recovery performance may lead to a large reduction in the actual oil produced.

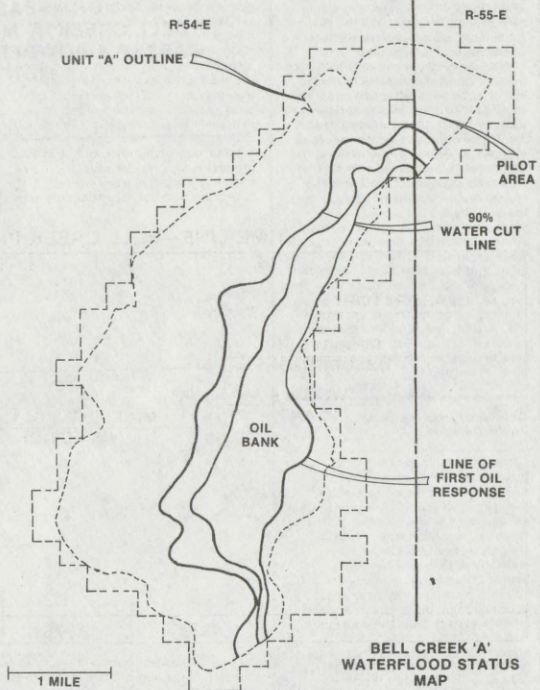


Figure 4—Bell Creek Waterflood Status: To accurately calculate the oil produced by EOR methods, the EOR pilot test is placed behind the secondary waterflood.

Tapping the Leftover Oil

Finally, of course, the EOR processes need further development and refinement. For example, the chemical surfactants used in micellar/polymer processes are highly sensitive to salinity and temperature—and cannot be used in reservoirs with very saline water or high temperatures. Plus the chemical slug size and injection rate must be precisely tied to such reservoir characteristics as its thickness and porosity, the nature of the rock, crude oil properties and character of the coexisting formation water. As Doscher of USC puts it,

"There are some very difficult technical problems in the micellar/polymer process. And it requires a very sophisticated formulation to make it work."

Once researchers have refined these technologies, they may still face some serious roadblocks. For example, the injection materials—chemical surfactants and CO₂—will be needed in extremely large quantities. Getting enough of these materials in a timely manner may be difficult. But, if EOR processes face tremendous uncertainties, they also have tremendous potential—both for the producers and

for the nation. Billions of barrels of oil, now locked underground, may be produced through EOR processes. In fact, by 1985, the Congress' Office of Technology Assessment (OTA) predicts that EOR processes could be producing from 0.4 to 1.3 million barrels per day—depending on process performance and on economic incentives. By the year 2000, estimates of the EOR contribution range from as low as 1.1 to as high as 8.2 million barrels per day. All of which represents "new" energy supplies for the United States.

TIME LINE—BELL CREEK PILOT

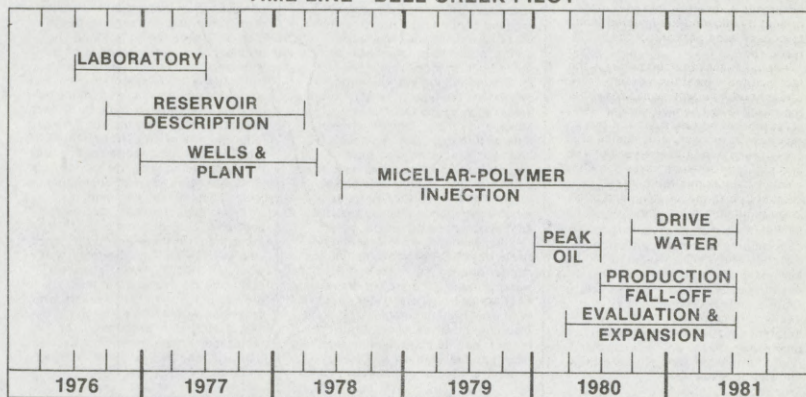


Figure 5—Time Line, Bell Creek Pilot: Moving an EOR project from laboratory to production is a long, expensive process. As this time line example shows, the Gary project starts injection of chemicals into Bell Creek Unit A in 1978. Project operators must wait more than a year before significant amounts of oil will start flowing from project wells—and before they can evaluate the success of the Bell Creek project.

EOR and the Ecosystem

An Environmentally-Clean Exotic Energy Technology

What will happen to the ecosystem as EOR projects move ahead? For many exotic energy technologies, that question is a very sensitive one. For, as most concerned onlookers are well aware, the exotic technologies frequently bring with them serious environmental and socioeconomic problems—problems that range from severe air and water degradation to the disruption of critical wildlife habitat to the nightmares of boom-bust economic cycles in small towns.

As an exotic energy technology, however, EOR gets a fairly clean bill of health. Implementation of EOR methods is essentially a very sophisticated extension of secondary production techniques. EOR's environmental impacts should be comparable to the negligible impacts of the conventional secondary technology. And, its socioeconomic impacts should provide more pluses than minuses.

That does not mean, of course, that EOR technologies are completely free of environmental and socioeconomic impacts. Like all energy technologies, they do pose some potential problems. One of these is the possibility of air pollution from the thermal EOR processes, where the creation of steam will produce some atmospheric pollutants. In general, these pollutants can be controlled by existing technologies, economics permitting. California, however, may be an exception. That state has adopted very strict air quality standards, which may limit the expansion of EOR thermal processes.

The high-potential EOR chemical processes may also present some environmental concerns. Chemical injection is conceptually similar to conventional secondary waterflooding methods. But, as Dr. Raymond Millemann, a member of the DOE environmental research staff at Oak Ridge National Laboratories in Tennessee, points out: "It is a little different because we are injecting chemicals into the oil reservoir that might have some toxic effects if they showed up elsewhere."

These toxic effects could cause water pollution problems if the injected chemicals accidentally flowed from an oil reservoir into underground water supplies, or aquifers. However, the likelihood of this happening is very remote. First, impermeable rock barriers surround the reservoirs. (That is how the oil was trapped in the first place.) Thus, it is extremely rare for water injected in secondary waterflooding to seep through to aquifers. Other injected materials should behave no differently. In the rare case where a path does exist between reservoir and ground waters, good planning can prevent seepage. And, as Millemann points out, both environmental and economic impacts would dictate good planning. "The chemicals are very expensive," he explains, "so producers don't want to lose them. Thus, producers should take the proper precautions and safeguards to confine the chemicals to the site. If they do this, there is only a very small possibility of contamination of ground water."

Land disturbance is another environmental problem which must be investigated for EOR projects. In general, the EOR projects will use the same facilities as primary and secondary production, thus minimizing land disturbance. But, in some areas, new wells will have to be drilled, old wells plugged and new roads built. In these cases, the environmental impact will naturally depend on the type of terrain. In open areas, such as the Gary site, Millemann notes, "there will be very little disturbance. But in places like West Virginia, where you have mountains and hills to deal with, there could be considerable land disturbance." Thus, some EOR projects will require safeguards against possible land disturbance problems.

Other potential environmental impacts from EOR projects include the danger of chemical spills and possible water problems if a project draws fresh water from local water supplies. With existing technologies and good planning, however, each of these impacts can be controlled. In fact, in a recent article, Michael McCloskey, executive director of the Sierra Club

noted: "Environmental problems posed by future development of enhanced recovery techniques do not appear to be severe, but require careful attention. It is well to bear in mind," he added, "that enhanced recovery programs are directed at areas that have already been heavily developed."

Some EOR projects, of course, will face more serious problems than others. "Each site is different and must be considered separately," Millemann stresses. "The terrain, the surface and ground waters, the length of time the field has been in operation may all cause different environmental concerns." In the case of a project like Gary's Bell Creek, he adds, the potential for environmental problems is very small. "Bell Creek is a new field, with up-to-date equipment," he notes. "The project operators have done their homework and overall it looks very good. But in general," he cautions, "I could not say that EOR projects will have minimal impact. However, if the project operators worry about the sorts of things I've been discussing, they should have very little impact."

The socioeconomic impacts from EOR projects may be of even less concern. In fact, they should be positive rather than negative. Unlike many other exotic energy technologies, EOR projects do not have the problem of minimum size to contend with, and so need not cause the tremendous influx of workers that now plagues many small communities near massive energy developments. In fact, Goldburg at Gary points out: "We can tailor the size of an EOR project to the financial and socioeconomic needs of the surrounding area. We can do 400 or 40,000 acres at once, depending on what is best for the communities."

Rather than create socioeconomic problems, EOR projects should help avoid them for these new projects will help keep fields open that otherwise would shut down. As EOR backers point out, the projects will thus provide jobs for oil field workers who otherwise would lose their jobs at the end of secondary production. So, rather than create boom-bust cycles, EOR will lengthen the life of existing oil fields.

The EOR Gamble

A "Near" Term Exotic Energy With High Risks/High Rewards

On one side of the coin, it's an energy source for the immediate future, with an enormous resource base, technologies that are already in field testing and the potential for very high rewards—in energy, in jobs and in dollars. On the other side, it's a high risk gamble, with difficult technological uncertainties, very high costs and the ever-present potential for failure.

On the positive side, government reports rate EOR processes as "near" term technologies (see Figure 6) with

an expected energy impact at least one-third as great as any other exotic alternate energy resource. Even with recovery efficiencies as low as 30 percent (considerably below current field test results of 60 percent), total EOR production would equal one-third of all oil production to date in the U.S. In other words, EOR technologies would net 30 billion barrels of domestically-produced oil—"new" oil that otherwise would have to come from foreign sources.

In addition, the infrastructure for EOR techniques is already in place. The methods will use the same refineries, pipelines and, in many cases, even the same wells as primary

and secondary recovery methods. Also, the estimated costs for these projects are based on current values existing for materials, as the chemicals needed for EOR methods are already in commercial production. Thus, EOR estimated costs come from fairly well-known, reliable numbers—as opposed to the uncertain, and inevitably underestimated, "paper" numbers for many of the other exotic energy technologies.

With these advantages, EOR methods appear to be on firm ground—until the many technological uncertainties are considered. These uncertainties place EOR in a high-risk investment category. And, they

PROSPECTS				DOE
TECHNOLOGY	TERM	INFRA- STRUCTURE IN PLACE	IMPACT IN YEAR 2000	
			Million Equivalent Bbls/d	
EOR (Chemical, CO ₂ , Thermal)	Near	Yes	5	
Coal Direct	Near	No	12	
Nuclear	Near	No	14	
Geothermal	Mid	No	2	
Shale	Mid	No	3	
Coal Syn Fuel	Mid	No	7	
Solar/Breeder/Fusion	Long	No	3	

Figure 6—Exotic Energy Technology Prospects: The nation needs more energy today. But, most new energy technologies are still far in the future. As this chart, developed by the Energy Research and Development Administration (now DOE) shows, only a few of the exotic technologies, including EOR methods, are now classified as "near" term prospects—prospects that may come to fruition within the next few decades.

naturally make EOR projects less-than-attractive gambles for prudent investors.

The EOR Bottom Line Risk/Reward Probabilities

To illustrate the EOR gamble, the projected financial data for a full field micellar/polymer flood in Bell Creek Unit A is given in Figure 7. (These numbers can be generalized to a base case reservoir of 10 million barrels original oil in place with primary plus secondary recoveries of any given percentage.) As Figure 7 reveals, in order to develop the field

for tertiary oil, Bell Creek operators must spend \$140 million for injection chemicals—chemicals which must be pumped into the ground before oil is produced. For a small independent oil company, working with limited assets and using an unproven technology, this poses an insurmountable capital formation problem.

If independents are to produce the oil left over after secondary recovery, they will need some financial assistance. But so long as the EOR techniques are still unproven, this assistance will not come from traditional lending institutions. First generation EOR projects are considered too "high risk" for these institutions.

The risk inherent in an EOR project, before the technology is proven, is illustrated by Figure 8. This computer simulation, based on Bell Creek Unit A, calculates the probability of the operators receiving a given discounted cash flow rate of return on their investment. The uncertainties considered in this simulation include:

- Crude oil price (ranging from \$15 to \$25)
- EOR recovery (35 percent to 55 percent)
- Chemical costs
- Operating costs
- Capital costs

As Figure 8 shows, the operators have a 50 percent chance of receiving a 15-percent rate of return. But, with a high-risk project such as an early EOR effort, prudent investors would look for a rate of return in excess of 15 percent—probably over 25 percent. As the Figure shows, the probability of this rate of return is only about one chance in 100—not sufficient to attract knowledgeably ventured capital.

Financial Incentives: Investing in the Future

Between high risks and high front-end costs, independent operators will need some financial incentives to pursue EOR projects. Figure 9 examines some possible incentives and their implications for Bell Creek Unit A. The figure displays the cumulative net cash flows after tax for a full field flood with three different

**FIGURE 7
PROJECTED FINANCIAL DATA
MICELLAR-POLYMER FLOOD
BELL CREEK UNIT 'A'**

Original Oil in Place (OOIP)	122 million barrels
Primary Plus Secondary Production*	58 million barrels (estimated)
Net Worth of Production**	\$230 million
Net Worth of Production After Taxes (assume half)	\$115 million
Available Capital for Tertiary Target (10% N.W.A.T.)	\$12 million
Available Tertiary Target	64 million barrels
Expected Tertiary Recovery	28 million barrels
Chemical Costs for Tertiary Target (\$5 per Tertiary Barrel; as per Pilot)	\$140 million
Capital Formation Problem	(\$128 million)
*49 million barrels (12-31-77)	

**Net Value of Production Less the Value of the Capital Investment, the Operating Costs and the State Production Taxes, all over the primary plus secondary production lifetime. Federal and State Income Taxes have not been deducted.

The EOR Gamble

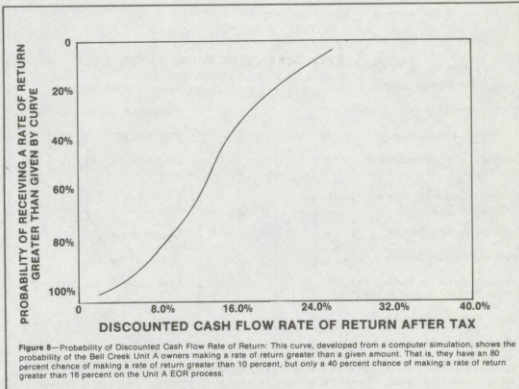
financial incentives: A) a guaranteed oil price of \$17/barrel, with no financing aid; B) a guaranteed price of \$17/barrel, with 90 percent guaranteed loans; and C) a guaranteed price of \$25/barrel with no financing aid. The chemical costs are capitalized and are not escalated, but are based on current costs. In this regard, cash flows of Figure 9 are optimistic, as chemical costs will certainly rise. The full-field phased recovery represents a production/logistics strategy of maintaining constant chemical fluid injection rates in order to optimize the balance between operating costs and capital investment. The resulting time schedule is consistent with that projected by DOE for micellar/polymer floods.

For the cases presented above, the maximum negative cumulative net cash flows after tax (MNCNFAT) are respectively:

Incentive Cases	(MNCNFAT)
Case A) \$17/bbl, no financing	(\$45 million)
Case B) \$17/bbl, 90 percent financing	(\$ 6 million)
Case C) \$25/bbl, no financing	(\$35 million)

With the exception of Case B, the capital formation problem for a micellar/polymer flood is far beyond the financial resources of the independent owners of the Bell Creek field. The same would naturally be true for any individually-owned property. And, given the high-risk nature of early EOR floods, no help will be forthcoming from traditional financing sources.

Thus, to stimulate maximum EOR investment and recovery, some government financial incentives will be needed. Gary Operating Company favors a support price of at least \$17 per barrel for EOR crude plus a



guaranteed loan program such as presently awarded by the Geothermal Energy Research, Development and Demonstration Act of 1974. Therefore, Gary Operating Company favors Senate bill 2999 as recently introduced by Senators Gary Hart (D-CO), Floyd Haskell (D-CO), Pete Domenici (R-NM) and Charles Percy (R-IL). As shown in Figure 9, the combination of price guarantees and guaranteed loans, as proposed by this bill, would make high-risk EOR projects feasible for independent oil companies. Additionally, tax incentives could enhance the desirability of investment in EOR projects.

For a nation faced with ever-dwindling energy supplies, such incentives represent an investment in the future. According to some energy experts, EOR techniques could start

providing the nation with as much as one billion barrels of oil per year by 1990. By the turn of the century, that figure could rise to two billion barrels per year. Thus EOR technology offers tremendous potential rewards, both for the nation and for the producers. But, they also carry very high risks—which preclude traditional loan commitments by lending institutions.

If EOR projects are to start producing significant amounts of oil in the near future, financial incentives are needed to cushion the risk and assure the participation of the financial community. Incentives such as those suggested above will help draw in a wide range of investors—major oil companies, lending institutions and independent oil producers—to help bring EOR production on stream in the 1980s.

The EOR Gamble

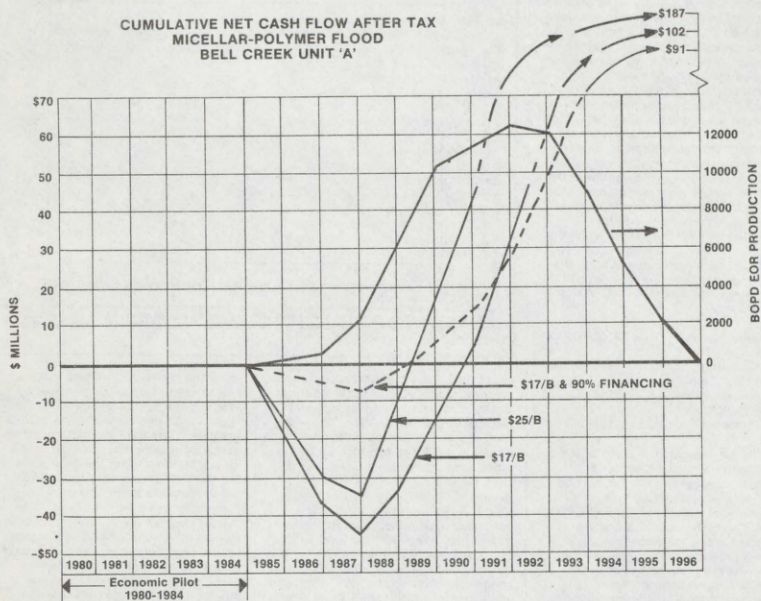


Figure 9—Projected Cumulative Net Cash Flow After Tax, Bell Creek Unit A: A severe front-end cost crunch could push many would-be developers out of the EOR arena. This chart, developed for Gary's Bell Creek Unit A project, shows the negative cash flow burden facing the producer after a successful economic pilot with an EOR price of \$17 per barrel, a price of \$25 per barrel and a price of \$17 per barrel with 90 percent financing.

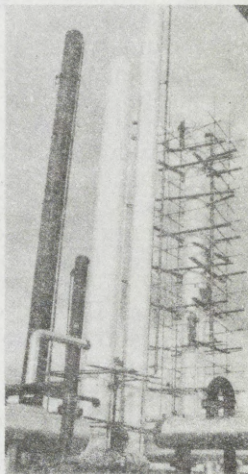
EOR Can Help Solve Our Nation's Energy Problems... If We Act Now



The energy crisis is here to stay. Enhanced Oil Recovery, even with its vast potential, cannot change that fact. At best, EOR will eventually supply the nation with three million barrels of oil per day—a significant help when compared to the more than eight million barrels per day that the nation imported in 1977. EOR cannot cure the energy crisis, but it can buy our nation precious time to deal with that crisis and to lessen the balance of payments problem. The question of how fast EOR processes come on stream to help buy this time is now largely in the hands of industry and U.S. government energy decision makers.

Independent oil producers, who are responsible for approximately 40 percent of U.S. oil production and, by inference, 40 percent of the nation's reserves, cannot enter the EOR arena—unless they receive some financial assistance. The front-end costs for EOR chemical projects far exceed the independent's available capital resources. As EOR projects depend on new technologies, they must be viewed in the same category as other exotic energy replacement resources—such as shale, synfuels and geothermal. Thus, the government should provide equivalent economic incentives. Suggested incentives for EOR projects are: loan guarantees, price incentives and tax benefits.

For more information on Enhanced Oil Recovery, and the Bell Creek Field, contact Dr. Arnold Goldberg, Manager of Enhanced Oil Recovery, or Michael J. Driver, Vice-President and General Counsel, Gary Operating Company, Four Inverness Court East, Englewood, Colorado 80110 (303) 770-4710.



Senator HASKELL. Thank you, sir. I have some questions. I will defer to Senator Bartlett.

Senator BARTLETT. Dr. Goldberg, the 90-percent financing you are talking about, would that be total financing from Government sources and private sources, or would that be contemplated to be Government loans, or just what?

Dr. GOLDBURG. The Gary Operating Co.'s position is that guaranteed loans is a very effective way to proceed. It allows the operator and his traditional financing institutions to work together as they have in the past. When the EOR technology is proven and the financial institutions feel comfortable with this technology (as they now do with secondary recovery technology), then the full faith and credit of the U.S. Government can be withdrawn—the hidden hand of the Government can be withdrawn—and leave the infrastructure of the lending institutions and the operator fully in place. We feel that this is a very useful way to proceed.

Senator BARTLETT. Wouldn't a first step on a broad basis be better for everybody, including your company, if there was decontrol, not just of the increment but of the entire production from tertiary projects?

Dr. GOLDBURG. We feel, as does the rest of the industry, that deregulation would be helpful to the production of petroleum in the United States.

Senator BARTLETT. I thank you very much, Dr. Goldberg.

We may have other questions and I will be happy to——

Mr. DRIVER. Let me just add one further thing.

Senator BARTLETT. Yes.

Mr. DRIVER. In looking at our numbers, the amount of incentives that full deregulation would provide would depend on where the individual operator was in his waterflood. In other words, if you are approaching the end of the waterflood, then the amount of incentive that that deregulation provides is minimal and may not be sufficient. In that instance a loan guarantee may have to stand in its stead.

Senator BARTLETT. I thank you, Mr. Driver.

Dr. Goldberg, thank you for your testimony.

Mr. Chairman, thank you.

Dr. GOLDBURG. Excuse me. If I may just reinforce what my colleague said. In the case of Bell Creek, we are at the point in the secondary recovery where deregulation would have to be instituted today to enable the working interest owner to pay for the front-end chemical costs of a tertiary flood. So the helpfulness of deregulation to EOR capital formation depends upon the production position of the particular field. For those fields which are completely watered out, it will offer no incentive. For those fields which are still early in their primary and secondary production, it may solve the problem.

Senator HASKELL. I gather from your chart here that in addition to some kind of loan guarantee there would probably have to be some kind of adjustment in price. If you use \$17 a barrel, the world price now is around \$14. So in order to—have you calculated this at \$14?

Dr. GOLDBURG. We have it calculated at \$15.20 and the maximum negative cash flow at \$15.20——

Senator HASKELL. Say with 90 percent financing.

Dr. GOLDBURG. Well, if we can just—I do not have that—or it would take it too long to get it out of my briefcase.

But essentially the answer is that price—I think there is a very important point here—that is that price as an incentive has a small influence on maximum negative cumulative net cash flow. The reason is that in an EOR chemical flood, you put the chemicals in the ground now and you get the production 2 or 3 years later. At \$15 a barrel, the maximum negative cumulative net cash flow is \$48 million and ratioint it by eye from exhibit 12 with 90 percent financing, the working interest owners might still be able to accommodate the \$7 million in required risk capital.

Senator HASKELL. But maximum negative cash flow 48 million, I guess where I am curious is where you would come out, assuming you had your 90 percent financing, where would you come out at the end of the road?

Mr. DRIVER. I might just add that one of the reasons \$17 a barrel was used is that there is a fairly long lead time before you actually start producing tertiary oil from a tertiary project, and it was our estimate that by that time—The late 1980's—that the price of oil would have reached \$17.

Senator HASKELL. Why this is interesting is one of the bills before us talks about, I think, authorizing \$200 million for price guarantees of up to \$25 a barrel. I suppose it would depend in process to process what price would be appropriate so that people could make money out of tertiary recovery, and that would depend on the nature of the field, I suppose, and also the process used. Would I be correct on that?

Dr. GOLDBURG. That is correct. The Bell Creek Field is a relatively large field. It is the 84th largest field in the United States. If you went to smaller fields, then the maximum negative cumulative net cash flow would be smaller; and the funds provided by the bill, one of the witnesses indicated, would cover about 10 to 12 fields because they wouldn't all be put under chemical flood at the same instant of time.

Senator HASKELL. Really what you have constructed here is the cash flow statement and also, I assume, a profit statement based upon what would be a realistic price of oil commencing in 1985. That is about what you have done.

Dr. GOLDBURG. That is correct. There is another curve, exhibit 11, speaking to what the discounted cash flow rate of return would be.

Senator HASKELL. Where is that?

Dr. GOLDBURG. It is exhibit 11.

Senator HASKELL. OK.

Dr. GOLDBURG. What we did here was to vary the price of oil from \$15 to \$25 a barrel, the tertiary recovery performance from 35 to 55 percent, and we related the chemical costs to crude oil price, since crude is the feedstock for the chemicals; and we did what is called a probability simulation with a computer—a "Monte Carlo" analysis. Along the horizontal line in exhibit 11 is the discounted cash flow rate of return after tax. Again, this is the same Bell Creek, unit A, deployment of an enhanced oil recovery project by micellar flooding. And along the vertical axis is the probability of receiving that particular discounted cash flow.

If you let your eye concentrate on a 15-percent discounted cash flow rate of return, which most businessmen would look upon as a reasonable rate of return for a very conservative, safe business project, the probability of getting that is 50 percent.

Because EOR is such a high risk technology, at least at the beginning, I think most businessmen would look upon 15 percent rate of return as a very poor return for such a high risk and would look at least for a 25-percent rate of return, probably 100 percent. But on this curve you will see that for a chemical tertiary flood in Bell Creek unit A the likelihood of receiving a 25-percent rate of return is 1 in 100.

Senator HASKELL. So it is basically your conclusion, I gather—I don't want to put words in your mouth—but I gather that it is your conclusion, for an independent, anyway, some kind of a guaranteed loan is necessary. Also, I would gather from this, initially until your process is perfected and tested, some kind of Federal payment in addition to the world price would be necessary to induce the project to go forward. I don't want to put words in your mouth, now.

Dr. GOLDBURG. Yes; I would concur in your characterization of the message of my presentation.

Mr. DRIVER. Or having the oil produced from enhanced oil recovery techniques be treated as stripper wells are presently treated. In other words, to receive the world market price.

Senator HASKELL. World market price at—oh, I see.

Mr. DRIVER. In conjunction with a loan guarantee, world market price should be sufficient incentives, at least based in the numbers that we have done in the Bell Creek project.

Senator HASKELL. And making the assumption that world market price in 1985 is \$17. We make that rough assumption.

Dr. GOLDBURG. Yes. The projected world market price.

I might, if I may, reinforce your first point. I think that without guaranteed loans the independents, who now produce about 40 percent of the oil in the country and, by inference, control about 40 percent of the reserves, without guaranteed loans the independents will not participate in EOR and will default to the majors.

Senator HASKELL. Thank you, gentlemen. I appreciate very much your presentation. I regret you didn't have more time.

Senator Bartlett, do you have anything further?

Senator BARTLETT. No.

Mr. DRIVER. Thank, you.

Dr. GOLDBURG. Thank you very much.

Senator HASKELL. Thank you. Our next witness is Mr. Dutton. Are you Mr. Dutton?

Mr. DUTTON. Yes; I am Mr. Dutton.

SENATOR HASKELL. Right. Go ahead, sir.

STATEMENT OF GRANVILLE DUTTON, DIRECTOR, GOVERNMENT RELATIONS, SUN PRODUCTION CO., DALLAS, TEX.

Mr. DUTTON. I am Granville Dutton, director of Government relations for Sun Production Co. I have been in this job only 6 weeks and the 28 years before I have been intimately associated with the exploration, development, and production of oil and gas, my most recent job being as manager of joint operations. In this job I also held the position of vice president and director of Canyon Reef Carriers Corp., a corporation which not only designed, but financed and built and is operating the 220-mile long CO₂, carbon dioxide, pipeline which

furnishes carbon dioxide to the world's largest tertiary enhanced project, the SACROC unit of the Kelly Schneider Field in Scurry County in Texas.

I have submitted an abstract of my testimony, specific answers to the questions propounded and the testimony in chief, but I would like to take advantage of the limited time by——

Senator HASKELL. Mr. Dutton, I am going to, unfortunately, have to go to the floor because the conversion bill is on the floor, but Senator Bartlett will chair and continue the hearing. I apologize, but this is just life.

Mr. DUTTON. I am sure your staff assistant can pass the word on to some of the questions you had that I wanted to comment on.

Senator HASKELL. Thank you very much.

Mr. DUTTON. Thank you, Senator.

Senator Bartlett, with your permission, I would like to just deviate from my prepared testimony and comment on some of the questions that have come up during the course of this hearing.

First, may I say that I endorse wholeheartedly Senator Bentsen's bill S. 2623 and can say without any question in my mind that the adoption of this bill will put the United States into the enhanced oil recovery business in a very rapid fashion. In fact, in my opinion, there will be at least 1,000 projects going within 1 year to 18 months with the primary limitation being personnel and materials, because I believe it will provide the incentive that is necessary to really attack this very large potential.

I have no objection to——

Senator BARTLETT [presiding]. Could I ask you a question?

Mr. DUTTON. Sure.

Senator BARTLETT. If you define enhanced recovery to include secondary and waterflooding, would you favor proposals to deregulate the price on all enhanced recovery, including waterfloods and other secondary methods?

Mr. DUTTON. Yes, sir, I do, and that would certainly further enhance the domestic production of the United States. One of the real problems with price controls is that they are so counterproductive because a company operates on a rate of return and has to make a profit.

So often people say, "Well, there is so much money around; why don't you go ahead and invest it?" But people don't invest money regardless if they have a million in the bank or a billion in the bank, they don't invest money in a losing proposition.

Today the real problem is that the bulk of the reserves in this country that are attackable under both secondary and tertiary are located in the 100 largest fields in the United States and these are primarily lower tier prices. We are unable to make any capital investment in these areas because the rate of return will not permit such capital investments for the lower tier price.

Senator BARTLETT. Is that \$5.25 oil generally, in that neighborhood?

Mr. DUTTON. Yes, sir. It is up to about \$5.53 now. In the SACROC unit, with which I am most familiar, we are currently injecting carbon dioxide costing us in excess of \$5.60 for each incremental barrel, and for that incremental barrel, we are receiving \$5.53 before royalty, taxes and operating expenses, and obviously aren't making any profit out of that.

With respect to the overall cost, though, and not honing in on any one particular field, we agree pretty much with the Lewin estimate that overall the investment required to really put the enhanced oil recovery business in its most effective operation would require about \$150 billion investment. This is a tremendous cost and as all the witnesses have mentioned it involves a tremendous risk, but so are the rewards tremendous. Of the 300 billion, that all of the witnesses agreed—and I might comment that I have never heard such agreement on the factual matters in a hearing before in my life, that we all seem to have the same numbers and agree with them—but that this roughly 25 billion that represents, in my opinion, what is a real estimate of what we can do with current technology and current world prices. In other words, the economic expectation if Senator Bentsen's bill were adopted is 25 billion barrels. It is going to cost \$150 billion.

One of the things I would like to dispel in the minds of people are the thoughts that somehow Bentsen's bill would be a bonanza. I think that the real way to look at it is not in the fact that it might result in \$2 billion more coming to the industry in the next year after it was adopted, but more we ought to look at what it would do to the cost to the consumer; and that amounts to exactly 1 cent a gallon. Now, for that 1 cent a gallon the consumer is protecting a 25-billion-barrel natural resource.

I think that one of the things that has been brought out here—but I would like to really emphasize it—is that in the year since the DOE has been considering enhanced oil recovery regulations; in my judgment we have lost a billion barrels of potential EOR and that we are going to continue to lose a billion barrels every year that we provide no incentive for developing it. I am certain that in 25 years, if we don't do something, in 25 years there will be no enhanced oil potential in this country. I really believe 15, but I am giving myself an extra 10.

That billion barrels that we have lost in the last year is going to cost us a minimum of \$14 billion to foreign operators. I think too often people don't realize that that \$14 billion is not some bonanza to the U.S. oil industry if spent for domestic production. One of the things that we ought to consider immediately is that 7 percent of that, or \$1 billion, are going to the producing States in the form of severance taxes; \$2 billion of that are going to royalty owners. And, if we are really going to put \$150 billion in the ground over the next 15 years, \$10 billion will go to other people in the United States for American labor and American materials to develop American resources.

I cannot overemphasize the time constraints upon which EOR is operating. In fact, it is my recommendation and my company's that unless this session of Congress passes it, we might as well forget it because it is too late and then the only thing we can work for is total decontrol, or this country will be in an even more serious energy situation than it is today.

That concludes my remarks.

Senator BARTLETT. Mr. Dutton, you commented on EOR and gave some figures. Does that include secondary or just tertiary?

Mr. DUTTON. Senator Bartlett, if Senator Bentsen's bill is adopted, secondary recovery as we have known it in the past will be over. From here on we will not observe a distinction between secondary and tertiary.

Tertiary in itself is a slight misnomer because sequential arrangement is not the thing that really produces. If Senator Bentsen's bill is adopted I dare say that 95 percent of all future recovery mechanisms will go the enhanced route because it will result in additional recovery of reserves by putting it in then, rather than as a standard secondary and complete it.

However, in those cases where for some reason tertiary is not applicable I agree that it would be very helpful for the decontrol to apply to secondary.

Senator BARTLETT. Well, isn't it true that a lot, perhaps even most, tertiary involves injection of water?

Mr. DUTTON. Yes, sir, that is generally true; some of it in the form of steam, of course.

Senator BARTLETT. So it seems to me that perhaps we are dealing a little bit here in terminology and definitions of terms. But that there would be—most tertiary has been methods that have followed secondary, or included secondary as a part of the operation. Is that not correct?

Mr. DUTTON. That is correct, sir, and I am suggesting that current technology indicates that it would be even more beneficial to recovery from reserves if those processes currently known as secondary were combined with our known technology for tertiary and installed at the same time.

Senator BARTLETT. Would you submit for the record an analysis of the potential of increasing domestic crude oil production through price incentives or secondary recovery oil, how much production would be forthcoming, what would be the estimated cost, how do the potential benefits of price relief for secondary recovery compare with those of tertiary?

[Subsequent to the hearing Mr. Dutton supplied the following information:]

RESPONSE OF GRANVILLE DUTTON TO QUESTIONS ON ENHANCED TERTIARY OIL RECOVERY

1. The tertiary enhanced oil recovery techniques offer a large but uncertain potential for increasing our domestic supplies of oil. The uncertainty is primarily a result of the price uncertainties that currently exist as the development of our enhanced oil recovery (EOR) is principally a function of price. A second uncertainty is the timing of removing the price uncertainty. Each day a portion of the enhanced oil recovery target available in the United States is being placed beyond the reach of EOR techniques. Therefore, the limits vary from a minimum of one billion barrels to a maximum of 76 billion barrels of EOR potential. It is my belief that should EOR incentives be promulgated by the 95th Congress, the most likely potential would be in the range of 25 billion barrels of increased supplies from EOR. Specifically, it is the opinion of my company that the most probable potential recovery is 27.7 billion barrels, with a range of between 15 and 52 billion barrels.

An ancillary question to increasing our supplies would involve the production rate at which these EOR reserves could be brought into the marketplace. In my opinion, the National Petroleum Council estimate, which closely parallels the Lewin study and forecasts a production rate of 3 billion barrels a day of enhanced oil by 1990, is a reasonable probability.

2. Financial incentives are needed for all tertiary enhanced recovery techniques. The best financial incentive would be to decontrol all oil prices since the primary reason there is no EOR industry in the United States today is the fact that price controls have prevented the development of these expensive barrels. In my view-point, there need be no different financial incentives to demonstrate a first-time application of a recovery technique on a particular type of reservoir since each reservoir is unique and this implies that each such project would be, in one sense

of the word, a "first-time, full-scale commercial" test. Tertiary oil recovery operations can be sustained only at prices which are above the current oil market price. Therefore, to initiate these projects, the potential operators of such projects must see an economic expectation of a rate of return sufficient to justify the risk in EOR operations. In my judgment, operators would willingly and quickly accept such risks if they were assured of the opportunity to seek future world-market prices for their production. Under current price controls, it is necessary that the total oil from an EOR project be deregulated to seek the world-market price in order to provide sufficient incentive for investors to make the huge capital expenditures necessary to institute EOR projects in the number required to effectively reduce the current import burden borne by the United States.

3. The relative merits of the various financial incentives for tertiary oil recovery are as follows:

(a) *Deregulation of the incremental oil produced from EOR techniques.*—There are no benefits to the producer since he would be unable to institute an EOR project if only incremental production is deregulated. The procedure would be basically unfair to the consumer since it would bring on no new domestic supplies and would result in the loss of a large national resource, forcing the consumer to rely on unstable foreign supplies. Although there would be no cost to the U.S. Treasury, there would be a substantial loss in Federal Income Tax that would accrue from the 25 billion barrels of EOR production that would be lost as a result of the lack of incentive.

(b) *Deregulation of all oil produced from a reservoir under an EOR project.*—This would be a sufficient incentive for producers to embark on the projects necessary to obtain the potential 25 billion barrel EOR reserve. This would result in the consumer paying approximately 1¢ a gallon more for the product, a 2 percent increase. However, it would increase the reliability of energy supplies and would be a small price to pay for such a large benefit. Not only would there be no cost to the Treasury, this incentive would likely result in increased Federal income tax revenues of more than 70 billion dollars at current prices as well as increasing state severance and ad valorem taxes another 5 billion dollars.

(c) *Price guarantees for "first of a kind" full-scale commercial operations* would be a benefit only in special circumstances where the project could not be financed by freeing the total production from price controls. As mentioned before, each EOR project is in a sense a "first of a kind" since each reservoir to which such techniques are applied is unique. However, there would be some special cases in which a producer would benefit by being able to finance a project. The guarantee insofar as it is above the world-market price would add cost to the consumer and would involve expenditures from the Treasury. In my judgment, the number of projects to which this incentive would be applied and the amount involved would be small.

(d) *Adjustments to the "composite price" structure.*—These would be necessary so that such EOR production that did attain the world-market price would not lower the price of other oil under price controls. This is necessary in order for those producers who have access to the largest targets for EOR to be free of the negative incentive that additional income generated by EOR projects would be offset by lower prices applied to other oil production which they own.

4. I have no knowledge as to the extent that small producers need loan guarantees in order to undertake a first full-scale commercial demonstration of an EOR technique. I believe that there would be only a limited number of specialized cases. The real incentive for instituting large-scale EOR projects across the nation would best be met by a combination of the following:

(a) Freeing all oil from a bona fide EOR project from price controls;

(b) A simplified accrediting procedure for EIR treatment which could probably best utilize state regulatory agencies;

(c) An assurance that a classification freeing EOR production from price controls could be removed only for fraud or failure to institute and carry out the EOR project; and,

(d) Exempting all EOR production sold at world-price market prices from the composite pricing mechanism.

Senator BARTLETT. Now, in many of the tertiary programs the more expensive part of it lies with the secondary recovery phase, or the injection of water, in which it is necessary to take it out to infinity, as you know, necessary to drill as many injection wells as you drill production wells. Also, in addition to that you have the water treatment and you have the source of water and the pumps for pressure, and so

when we are dealing with this I am afraid that what you said is not the way I would look at it exactly. I would see more recovery coming from secondary by waterflooding than I would by taking that to its limit and then adding something to it. What you are saying is that you are going to do them both at the same time.

Mr. DUTTON. To the extent that it is possible. However, I see an area in which your suggestion would certainly be beneficial to the country.

One of the real problems I mentioned earlier is the availability of materials for tertiary. We estimate that, for instance, it will require 100 billion pounds of surfactant, and our current capacity to manufacture is roughly 500 million pounds. So in the interim I would presume that there will be a great demand for that particular material in those reservoirs which have, as you mentioned earlier, the high potential probability of success, leaving a large number of other reservoirs which would have available to them only the secondary process of water in the immediate future, and that these would be enhanced and the incentive would be there for enhancing the recovery through plain waterflood if price controls were removed from secondary as well as tertiary.

Senator BARTLETT. Is what you are saying that the tertiary or the exotic methods will be used in preference to the waterflooding? As time goes on that there will not be waterflooding?

Mr. DUTTON. No, sir. I am saying they will be used in conjunction with the injection of water.

Senator BARTLETT. So you are talking about secondary. So you look upon the Bentsen bill, then, as being a combination of secondary and tertiary.

Now, the bill that I discussed that I am introducing today definitely deregulates enhanced recovery oil, as the Bentsen bill does, and I call it an enhanced recovery bill. But it includes very definitely secondary and tertiary recovery. So if a person would engage in secondary oil recovery by waterflooding or any other secondary method, he would get the same benefits.

Now, it seems to me that the overall approach of any method if a more important one because we are talking about known reserves so oil, we know where they are, we have a pretty good idea of what the economics are today, and it just depends on whether the price is sufficient to permit the development of those reserves. The leadtime is very important because as time goes on—and you brought it out, too—those fields will be plugged and no longer available for secondary or tertiary, or any combination of them.

I think maybe you are looking upon the Bentsen bill as I am looking upon the bill I am introducing, and perhaps it would be good to combine them into one program at some point. Perhaps we can do that.

Mr. DUTTON. Well, I misunderstood your bill. I thought it was for secondary rather than for either secondary or tertiary. Of course, the way you describe it, as I understand it, now, it is a broader bill than Senator Bentsen's and, therefore, would bring on a broader enhanced recovery effort—

Senator BARTLETT. That is right.

Mr. DUTTON [continuing]. Than Senator Bentsen's bill.

Senator BARTLETT. Well, maybe I described it incorrectly, but it is, as we call it, an enhanced recovery bill. It would include strictly

secondary, strictly waterflooding by itself, or any other secondary method, as well as tertiary.

Mr. DUTTON. I see.

Senator BARTLETT. And I think there is some mixup in terminology and definition between secondary and tertiary.

We went, I think, right up to the limit of your time, as I have calculated it, and I thank you very much, Mr. Dutton. We will have additional questions which we would appreciate your answering.

[The prepared statement of Mr. Dutton follows:]

STATEMENT OF GRANVILLE DUTTON, DIRECTOR, GOVERNMENT RELATIONS,
SUN PRODUCTION CO., DALLAS, TEX.

ABSTRACT

The United States has a significantly large potential of known oil in place which will not be recovered under current economic conditions. This target consists of three hundred billion barrels of oil whose location and general characteristics are known but which cannot be produced by current technology at existing prices. Should just 10% of this vast potential be recovered, it would equal the current known reserves of the entire United States, including Alaska.

Enhanced oil recovery processes may be generally classified as thermal, non-hydrocarbon gas miscible and chemical. At current lower tier prices, only a small portion of the thermal process, steam, is economic. California is the principal producing area for this process but environmental restrictions are effectively preventing any appreciable expansion of the process.

Neither non-hydrocarbon gas miscibility nor chemical processes are economic at current lower tier or upper tier prices. However, the tremendous potential offered by these processes would motivate producers to install numerous such programs if the economic and regulatory climate were appropriate. Since these processes require very large front-end capital investments and long lead time to increase production, there is insufficient incentive in any plan which would provide higher prices only for incremental production.

Should the total production from enhanced tertiary projects be exempted from price controls, there would be tremendous incentive to institute these programs in numerous areas of the United States; provided that such price incentives did not result in lower prices that producers receive for their other domestic production because of the composite price mechanism. Another incentive for these programs would be an authorization system which did not constitute an excessive regulatory burden and which assured that there would be no adverse changes in the regulations after the projects were underway.

Should these incentives be present, the National Petroleum Council's estimates of developing 25 billion barrels of enhanced reserve and a 3 million barrel per day production rate in 1990 could be achieved. However, time is of the essence in meeting these goals. Every day a portion of the target in-place oil is moving beyond the reach of the enhanced oil recovery process. This diminishing potential results from well abandonments dictated by current price controls which prevent generating revenues sufficient to offset the ever-rising cost of producing marginal wells. One promising proposal to extend the life of these target reservoirs is the deep stripper amendment (S. 2692) which would prolong production of wells below a depth of 2,000 feet by granting them an additional price incentive for rates above the current stripper limitation of 10 barrels per day.

In summary, there is a large enhanced oil recovery potential in the United States which can be evaluated and developed only under significantly different economic and regulatory climates than currently exist. The proper climate would involve freeing the total production from a bona fide tertiary enhanced recovery project from price controls, the certification of such projects as bona fide by a simple system such as utilizing the state regulatory agencies, guaranteeing that the relief granted would not be rescinded except for fraud or failure to institute the program and removing the crude provided this marketing treatment from the composite calculation.

In the event these incentives were present, it is reasonable to believe that the United States could bring on enhanced oil reserves equal to their current total reserves and could realize a production rate as high as 3 million barrels per day by 1990. It is estimated that such an increase would result in an increased price of

product of less than 5% and would create on the order of $\frac{1}{2}$ million new jobs in the total American economy. In addition, at current prices, the 3 million barrels a day would reduce the current trade deficit of some 25 billion dollars by over 15 billion dollars per year.

STATEMENT OF GRANVILLE DUTTON

The purpose of this testimony is to explain the need for price relief for domestic crude oil produced through the application of tertiary enhanced oil recovery (EOR) techniques.

Until 1972, very few knew, or cared, much about crude oil or petroleum products made from crude oil. Now, a working knowledge of the oil industry and its component parts is becoming critical to an understanding of our domestic and foreign economic difficulties. The difficulties include:

1. A weakened dollar.
2. High U.S. unemployment.
3. Increased inflation.

The passage of appropriate legislation to release from price controls approved tertiary EOR projects will beneficially affect these facets of our economy.

BACKGROUND

In 1977, we imported 3.2 billion barrels of crude oil and petroleum products at a cost to the American consumer of \$45 billion. This is equivalent to \$200 for every man, woman, and child in the U.S. Crude oil totaled 2.4 billion barrels, or 75 percent of total petroleum imports. Exhibit 1 shows the Value of Imports into the U.S. and the Merchandise Trade Balance, 1955-1977. Trends are readily apparent.

Christopher L. Bach, of the U.S. Department of Commerce, writing in the U.S. Department of Commerce "Survey of Current Business", April 1978, stated "The result (of crude oil imports) has been a transfer of income from oil importing countries to oil exporting countries * * * real income in oil importing countries has been reduced, as more domestically produced goods and services have been exchanged for imported oil." He further wrote, "An additional factor contributed to inflation, especially in the United States: because domestic oil and natural gas prices were often regulated and not permitted to rise to the prices of imported gas and oil, the supply of domestic oil and gas was curtailed, and demand was increasingly satisfied by high priced imported oil."

Exhibit 1, Merchandise Trade Balance, reflects this "transfer of income." As it indicates, the Merchandise Trade Balance showed a whopping, oil dominated \$25 billion deficit in 1977. In the first quarter of 1978, there was another massive \$11.2 billion deficit. It is these deficits that are contributing to inflation and the weakness of the dollar.

POSSIBLE SOLUTIONS

There are measures that can be taken to alleviate these economic strains caused by crude oil and petroleum product imports. These include:

1. Stringent conservation measures. Higher prices and other conservation methods have reduced the growth of demand from 5 percent in 1965-1970 to an estimated 1.2 percent in 1980-1985.
2. The increased use of alternative fuels. Government and industry are co-operating to replace petroleum, where possible, with coal, nuclear, synthetics from coal, oil shale, geothermal and solar energy.
3. Increased U.S. production from new oil fields. "Active drilling rigs" in 1977 averaged 1,976; substantially above the low of 975 in 1971 but still well below the 2,687 of 1955, a period when much of the oil we are currently consuming was found. With increased drilling, we can expect increased production.
4. Increased production from existing fields through the application of more expensive EOR techniques. These efforts are severely restricted by current price controls on domestic crude oil.

U.S. CRUDE OIL RESERVES

We, in the United States have been blessed with enormous petroleum reserves. Total discovered oil in place is some 450 billion barrels, of which we have produced and consumed 111 billion barrels in the 119 years since Col. Drake brought in his well. With economically "proved reserves" of less than 30 billion barrels, we

have 300 billion barrels that have been left in the ground. These 300 billion barrels are the target for tertiary enhanced recovery. (It should be noted that petroleum "reserves" is both an economic and technical term: it refers to those barrels that can be profitably produced at an assumed price. Any upward movement of price, therefore, increases reserves). As Exhibit 2 shows, almost 70 percent of the oil we know about is left in the ground. This occurred because the costs to get these additional barrels out of the ground were more than historical prices could justify.

Since 1972, substantial increases have occurred in the world prices of crude oil. A lot of United States crude has, under price controls, remained at relatively low priced levels. Because crude oil production is very price sensitive, the low price of U.S. crude has restricted reserves and impeded crude oil production.

U.S. CRUDE OIL PRODUCTION

What follows is a quick description of crude oil and how we get it:

The crude oil producing zone, when discovered contains water, oil, and gas. This mixture is found in small pore spaces (tiny holes) in the oil producing porous rock. These fluids exist under great pressure which are generally greater at deeper depths. It is this pressure that causes the gas to be dissolved in the oil.

When an oil well is drilled through the oil zone, the pressure causes the oil (and perhaps some water and gas) to flow into the wellbore where it is either pumped, or flows under pressure, to the surface. (Only a few oil zones, however, are fortunate enough to have a nearby underground supply of water to replace the oil as it is produced.)

Unless some sort of fluid injection program is started, nearly all oil producing ones experience decreasing pressure and production throughout their production history. As the pressure drops, oil no longer flows as easily into the wellbore, and production declines. The effect of this is that the average recovery rate by primary or natural means is between 20 percent and 30 percent of the oil in place. Seventy to eighty percent of the oil in place is left in the ground.

It is technically possible to increase this pressure through the injection of fluids near or into the oil in the ground. Historically, this has been called "secondary recovery", although it is difficult in most cases to distinguish between "secondary recovery" and "pressure maintenance". This occurs because waterfloods and gas injections now generally start before they are sharp drops in pressure. About 45% of all U.S. crude production is now on waterflood.

Even after a successful waterflood effort, substantial amounts of oil (up to 40-50 percent) on average are still in the ground. This occurs because some crude oils (no two are the same) have an affinity for the porous rock and stick to the grains of the rock. Other crudes are so viscous that they won't flow easily. California crudes are a good example. In other cases, the crude is good, but the surrounding rock is so tightly put together that oil can't flow through the spaces in the rock to the wellbore.

The large amounts of oil left in place have prompted people to test and use more exotic methods. These methods make use of a variety of techniques to free the oil from the porous rock and force it to the surface. Collectively, these tools, these techniques, are called "tertiary enhanced recovery", even though "tertiary" implies a sequential relationship that doesn't necessarily exist. All of the techniques we will discuss can be used as soon as the field begins production rather than as Step 3 in its life.

There are three major types of tertiary enhanced oil recovery (EOR) processes:

1. Thermal.
2. Chemical flooding.
3. Non-hydrocarbon gas floods.

THERMAL (HEAT RECOVERY)

There are three types of thermal recovery:

1. Cyclic steam (huff and puff).
2. Steam flooding.
3. In-situ combustion (fireflooding).

STEAM INJECTION

These recovery processes are generally used with oils that are so thick, so viscous that they won't flow easily. Heat reduces the viscosity and allows the oil to flow more easily. With steam injection, heat is put into the oil and the area surrounding it in the form of steam.

Cyclic steam (huff and puff) is the most commonly used type of thermal process. Steam generated on the surface is pumped under pressure down the borehole to heat the oil and area around the oil. After 3-6 weeks of this, (Puff) injection is stopped and the (Huff) or production phase begins; oil loosened by the heat (steam) is pumped from the borehole and the formation around it.

STEAM FLOODING

A second type of steam application uses injection wells rather than the borehole to inject steam. These injection wells move the heat farther from the borehole and use the steam to push the oil toward the producing wells.

IN-SITU COMBUSTION—(FIREFLOODING)

The third heat (thermal) method reduces the thickness of the crude oil by pumping air into the porous rock and burning, in place, some of the trapped crude. Increased pressure forces the remaining oil to the borehole.

CHEMICAL FLOODING

This involves the injection of chemicals, with water, that will loosen the grip of the oil on the surface of the surrounding porous rocks. There are a variety of chemicals that can be used, but they all fall into the general category of "Surfactants", and all are expensive * * * costing around \$6/barrel. One type, soaplike in nature, is selected on the basis of what works best on a particular type of crude and a particular type of rock. Another type is soluble in oil and is injected into the porous rock ahead of the water. The water pushes this surfactant, and the loosened oil through the oil bearing rock to the producing wells.

NON-HYDROCARBON GAS FLOOD

This method utilizes a gas that is non-toxic and non-explosive to "sweep" the oil from the pore spaces to the production wells. One of the more effective gases is carbon dioxide (CO₂).

None of these techniques is perfect; none of these tools will get all the oil. All, however, properly used, can sharply increase U.S. production and reserves.

Nobody knows exactly how much is available through EOR projects. Published estimates range from 1 billion barrels to 76 billion barrels based on a wide variety of assumptions used. With current reserves of 30 billion barrels, all of the estimates represent a significant amount. Our estimate as shown on Exhibit 2 is a range of 15 to 52 billion with 28 billion most probable * * * if adequate incentives are present.

Estimated future production rates also vary widely. A study by Lewin and Associates for the FEA in 1976 estimated EOR rates up to 2.8 million barrels per day in 1990 and the National Petroleum Council forecasted up to 3 million barrels per day for that year.

Existing production, however is only 373,000 B/D. This is segregated as follows:

Steam	250, 000
Thermal in-situ	10, 000
Chemical	3, 000
Gas	110, 000

The difference of 2.6 million barrels per day, shows that we have a long way to go.

Tertiary enhanced recovery takes more money, more time, and more talent than conventional primary recovery or secondary waterflood. Under existing federal price controls, however, it receives no special treatment.

More money.—Generally, the capital costs of an EOR project is 2-4 times the cost of traditional waterflood.

Item: Fireflood—The cost, today, of a 4800 foot air injection well in Northeast Texas is \$200,000. The 800 horsepower compressor used to inject air cost \$360,000 two years ago when it was new. The same compressor today costs \$450,000.

Item: A proposed steam flood in West Virginia is projected to have initial costs of \$2.7 million for a test program alone. If successful, total capital costs are estimated to be \$37 million.

More Time—Substantial time is necessary to bring various EOR projects to fruition. Often 4-5 years of planning are necessary before production work can

begin. This time lag obviously impacts costs. Tertiary enhanced recovery has a heavy "front-end load", that is, a lot of money is spent in the early stages, long before the increased production appears. And time is money.

The effect of the need for more money and more time sharply raises unit operating costs substantially above those of primary recovery. Unfortunately, the price per barrel, is the same. There currently is no distinction, under federal price controls, between primary recovery and tertiary enhanced recovery.

In summary, therefore, we can say that these tools cost more to use.

We also agree with a 1976 study by Lewin and Associates for the Federal Energy Administration stating, "the results of our analyses argue that EOR development is highly sensitive to the price of oil. Given that the greater proportion of tertiary production has been classified as "old" at prices at \$5.25 or less, one should not be surprised at the slow rate of EOR adoption. The producer is faced with a variety of choices, all based on the unique economics of his individual situation. With present costs and under the existing pricing structure, it is difficult for him to justify the investments necessary for EOR projects. All of us, therefore, are the losers.

Oil that should have produced is irretrievably lost when lower cost production is depleted and the field is abandoned and this is something that happens every day. To avoid this, crude oil prices must be above crude oil costs. A promising proposal to retard the abandonment of potential EOR reservoirs is S. 2692 which would expand stripper classifications to give economically marginal wells below 2,000 feet deep additional price incentives to continue producing.

Any proposal for increasing application of EOR techniques should have standards which include:

1. *Protection of the consumer.*—The plan should be designed to avoid windfall profits by the producer while continuing to furnish the consumer products at a competitive price.

2. *Simplicity.*—The plan must be easy to administer and enforce.

3. *Limited complicating side effects.*—The plan should avoid complicating existing regulations.

Based on these criteria, the only acceptable program is the decontrol of all production from approved tertiary projects.

Although this might appear to increase substantially the consumers cost, Exhibit 3 shows even a million barrels of EOR would increase the refiners acquisition cost only 41¢ a barrel—1¢ a gallon, or less than 2 percent.

If no action is taken, the price goes up anyway, as lower tier U.S. production is replaced by upper tier U.S. production and imported foreign crude and foreign exchange outflows continue or increase.

The only difference is the irretrievable loss of domestic crude oil. At current prices, this loss of 25 billion barrels of EOR would be the permanent loss of U.S. resources having a value of \$375 billion.

2. *Simplicity.*—The Carter Administration has also recommended the decontrol of all tertiary oil * * * but only that portion that is tertiary. While certainly a laudable objective, the administrative problems inherent in such a program would be incredible. The attempt to draw lines that would separate primary and secondary from tertiary would be an engineers nightmare and a lawyers dream. As Exhibit 4 shows, it would not provide the incentive to bring on the EOR potential reserve.

3. *Limited complicating side effects.*—By moving all tertiary oil outside the sphere of current controls, the existing structure remains intact with no additional pressures by producers to change controlled oil categories. Moving the crude to upper tier, would, for example, raise the average crude price. This would adversely affect lower tier crude prices and cause a reduction in "old oil" prices and production.

If this program is approved, we might ask ourselves who will benefit and by how much?

The report prepared by Lewin & Associates in 1976 estimated expenditures of \$150 billion over the next 30 years.

A lot of people will benefit:

1. Manufacturers of particular chemicals and CO₂ will benefit.
2. Manufacturers of pumps, of valves, and of pipe will benefit.
3. Manufacturers of general and specialty steels will benefit.
4. Well service companies will benefit.
5. Workover rig companies will benefit.

Four of these five businesses are labor intensive. We estimate that some $\frac{1}{2}$ million new jobs will be created by increased activity and production. Workers, therefore, will benefit. And what of the producer? It is very hard to be precise. No one knows what world oil prices will be. No one knows what tertiary operating costs will be. Therefore, nobody knows with any precision, what the producers profit will be. It should be noted that government will obtain the largest share of any profit involved. Exhibit 4 shows one scenario as to what might happen.

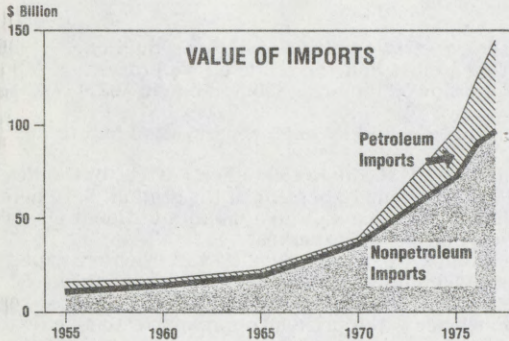
SUMMARY

1. U.S. petroleum demand has greatly outstripped U.S. production.
 2. We are currently importing almost half the crude oil we process.
 3. The vast dollar outflow for crude oil imports (\$36.3 billion in 1977) is severely straining our economy.
 4. We are taking steps to reduce demand through conservation and to increase supplies of other energy.
 5. We have found a lot of oil in the U.S., some 450 billion barrels, but under the current economic situation will leave about 70 percent in the ground. A 10 percent increase in our economic ability to produce will give us an additional 30 billion barrels, which is equal to our current proved reserves.
 6. To get this oil out of the ground, we need to develop and use more expensive techniques. Collectively, these techniques are called tertiary enhanced oil recovery.
 7. To recover this oil, we must allow the price of approved tertiary enhanced recovery projects to rise above costs.
 8. The cost to consumers will be slight, about 1¢ per gallon of product.
 9. The benefits to the economy are substantial. Each million barrels per day of foreign production @ \$14.52/bbl replaced by U.S. production means a foreign exchange savings of \$5.3 billion per year, and a reduction in inflation.
 10. These efforts will produce $\frac{1}{2}$ million jobs.
- Therefore, it is important that tertiary enhanced oil be decontrolled.

tic facts

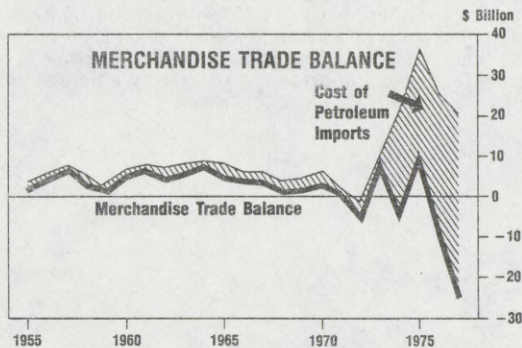
A Society of Petroleum Engineers program to promote understanding of fundamentals of the energy situation. *TIC Facts* is compiled by members of the Technical Information Committee: Granville Dutton (chairman), Glenn P. Carson, Philip C. Crouse, George C. Kunkel, C. A. Lombana, and Jim Pardee. (February 1978)

U.S. Trade Deficit Rises With Petroleum Imports



The value of petroleum imports has increased from . . .
 . . . 8 percent of total import value in 1972 to 31 percent in 1977
 . . . \$4.7 billion in 1972 to \$45 billion in 1977 — a *tenfold* increase in 5 years

- 1971 marked the first trade deficit in this century.
- The principal cause of the current trade deficit is the cost of imported oil.
- 1977's projected \$25 billion deficit is . . .
 . . . more than twice the previous high
 . . . greater than all previous deficits *combined*
- Deficits create job losses and inflation.



Developing Domestic Energy Reserves Could Reduce Trade Deficits

SOURCES: U.S. Dept. of Commerce (Washington): *Business Statistics* 1975 (May 1976) 14, 114, 117, 258; *Survey of Current Business* (June and Aug. 1977); *Commerce America* (Nov. 21, 1977) 18-20

SOCIETY OF PETROLEUM ENGINEERS
 A Constituent Society of the American
 Institute of Mining, Metallurgical, and Petroleum Engineers

Exhibit 1

TIC FACTS MAY BE REPRODUCED

U.S. ENHANCED OIL RECOVERY TARGET

[Billions of barrels; API, Dec. 31, 1977]

	Original oil in place	Ultimate recovery		Residual oil	
		Barrels	Percent	Barrels	Percent
U.S. total.....	449.9	148.5	33	301.4	67
100 largest fields.....	160.5	60.9	38	99.6	62
100 adjusted ¹	107.6	34.2	32	74.3	68
High recovery fields.....	17.5	12.6	72	4.8	28

¹ Excludes Alaska, OCS, high recovery fields.

POTENTIAL RECOVERY

	Achievable		Probable		Possible	
	Barrels	Percent OIP	Barrels	Percent OIP	Barrels	Percent OIP
100 adjusted.....	10.8	10	16.1	15	30.1	28
Other fields ¹	4.3	3	11.6	8	21.7	15
Total United States.....	15.1	3	27.7	6	51.8	12

¹ One-half of remaining fields.

REFINER ACQUISITION COST OF CRUDE OIL WITH AND WITHOUT TERTIARY PRICING

	Without tertiary (January 1978)		With tertiary (January 1978)	
	1977 U.S. production (millions of barrels)	Wellhead price/barrel	1977 U.S. production (millions/ barrels.)	Wellhead price/ barrel.
Lower.....	3.3	\$5.28	2.6	\$5.28
Upper.....	2.9	11.78	2.9	11.78
Stripper.....	1.1	13.89	.8	13.89
Alaskan.....	.8	5.29	.8	5.29
Naval.....	.1	12.38	.1	12.38
Tertiary.....		13.89	1.0	13.89
Total barrels.....	8.2	\$8.82	8.2	\$9.56
	Domestic	Imported	Composite	
Refiner acquisition cost without tertiary.....	\$10.14	\$14.52	\$12.15	
Refinery acquisition cost with tertiary.....	10.88	14.52	12.56	
Difference.....	+.74		+.41	

DISTRIBUTION OF VALUE—25,000,000,000 BARRELS OF EOR

[Billions of dollars]

	Only in- cremental released	Total projec released
25,000,000,000 bbl at \$15/bbl.....	\$375	\$475
Royalty at 15 percent.....	55	70
Severance tax at 7 percent.....	320	405
	22	28
Investment (including injected materials).....	298	377
	150	150
Operating costs at \$3/bbl.....	148	227
	75	75
Ad valorem tax increase at 1.3 percent.....	73	152
	5	6
Federal income tax at 46 percent.....	68	146
	31	67
Profit.....	37	79
Overall return on investment (percent).....	25.0	53.0
Over 20 yr (percent per year).....	2.5	5.3

¹ Assumes 10,000,000,000 bbl of controlled oil to attain world market price.

Senator BARTLETT. Mr. Russell, we have 13 minutes.

Mr. RUSSELL. Thirteen minutes?

Senator BARTLETT. More or less.

Mr. RUSSELL. That is my lucky number.

STATEMENT OF JAMES E. RUSSELL, CHAIRMAN, CRUDE OIL COMMITTEE, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA, WASHINGTON, D.C.

Mr. RUSSELL. Senator Bartlett, my name is James E. Russell and I appear before you today in my capacity as chairman of the Crude Oil Committee of the Independent Petroleum Association of America. I am also president of James E. Russell Petroleum, Inc., of Abilene, Tex., and Russell Engineering. I am a registered professional engineer in Texas and Kansas.

It is my privilege to be here today. The IPAA appreciates the opportunity to present our comments and recommendations to this committee regarding enhanced oil recovery legislation, not just because it is of great interest to our members, but also because of the national energy implications.

I would like to have this testimony presented in its total form and I will be very brief.

Senator BARTLETT. This testimony in its entirety will be reproduced for the record.

Mr. RUSSELL. Thank you.

I might add here that the IPAA represents more than 5,000 independent oil and gas explorer-producers who operate in every producing region of the country. We are vitally concerned with this problem and, in brief, I will say that I concur with all of the statistical data that has been presented to the record by the prior witnesses here today. As Mr. Dutton indicated, we are in fairly good agreement on those issues.

The IPAA applauds the efforts of this committee, Senator Bentsen and Senator Hart, in seeking to provide those positive incentives which are needed to maximize domestic energy production. Though there is some disagreement concerning the precise amount, the potential for increasing both the rate and ultimate total recovery of our crude oil resources through enhanced recovery techniques is universally acknowledged.

There is no doubt that if given market pricing now, enhanced oil recovery techniques could add significantly to domestic crude oil supplies in the very near future. And every additional barrel of domestic petroleum which is produced leads directly to one barrel less of petroleum imported.

I am going to skip through my prepared comments and just highlight the main points.

Senator BARTLETT. What was that last figure again?

Mr. RUSSELL. On page 3 of my written testimony, I stated that there is no doubt that if given market pricing now, enhanced oil recovery techniques could add significantly to domestic crude oil supplies in the very near future. This is important because each additional barrel that we produce will eliminate one barrel of imported oil.

Senator BARTLETT. Right, thank you.

Mr. RUSSELL. Mr. Chairman, let me preface my specific comments with respect to the two enhanced oil recovery bills currently before your committee by saying that I consider any version of an enhanced oil recovery bill to be a necessary evil. This is because it is primarily the legislatively enacted crude oil price control system that makes

such legislation necessary. Without price controls there would be less need for Congress to provide enhanced oil recovery incentives. It is evident to me that the solution to our current energy problem is really very simple: return to market pricing for energy.

In this respect, the IPAA fully endorses the concept underlying Senator Bentsen's bill, the Tertiary Recovery Incentives Act—S. 2623. This bill embodies the principles of market pricing by exempting from price controls all production from qualified enhanced oil recovery projects. It would bring to the full market price all petroleum produced from properties on which a qualified enhanced oil recovery process is being utilized by a simple and efficient mechanism.

A property would not qualify for this exemption unless it could be demonstrated that the enhanced oil recovery project could be expected to increase production. We believe that allowing market economics, rather than arbitrary administrative regulations, to determine whether a particular enhanced oil recovery project is or is not economically feasible is a far superior approach. This avoids additional paperwork burdens which are already onerous. It would be reasonable to assume that if enhanced oil recovery price exemption is contingent on extensive reporting, many independent producers would be unable to participate.

Because of the enormous cost and risk of enhanced oil recovery projects, it is appropriate that Federal price controls be suspended on all crude oil produced from the property, rather than just incremental production, as Senator Hart proposes in his bill.

While the IPAA greatly appreciates the interest and efforts of Senator Hart to encourage participation in enhanced oil recovery projects, especially by independent oil producers, we do have reservations about certain aspects of his legislation, the Enhanced Oil Recovery Commercialization Act of 1978—S. 2999.

One of the distinguishing features of S. 2999 is the loan guarantee provision. This would provide a maximum of \$200 million in loan guarantees for qualifying commercial demonstration projects for new and improved methods of enhanced oil recovery on a fieldwide basis.

If Congress should deem it necessary and appropriate to provide loan guarantees—a course of action that I am not recommending—then guarantees should be provided for the implementation of enhanced oil recovery technology, not the development of the technology itself. For the most part, the average independent producer does not have the staff, expertise or resources to engage in large, highly technical and complex enhanced oil recovery research and development activities. And the provision of a guaranteed \$25 per barrel for production from a first-of-a-kind enhanced oil recovery project would not be of much assistance to independent producers.

Since loan guarantees reduce the cost of borrowing—in some cases making borrowing possible—but do not reduce the inherent engineering risk, independent producers will still be reluctant to undertake risky enhanced oil recovery projects that expose them to financial ruin. Therefore, if such a program is implemented, the loan guarantees should have as collateral only those resources involved in enhanced oil recovery projects and should not place the independent's entire net worth at stake.

The conditions that must be satisfied to qualify for a loan guarantee under this bill would probably prevent most independent producers

from taking advantage of the program. In this respect it should be noted that unlike the Bentsen bill, which applies to enhanced oil recovery projects on a property basis, the Hart bill is more restrictive in that it applies to projects on a field basis. Furthermore, most independent producers simply cannot afford to wade through the lengthy and burdensome process of applying for the loan guarantee.

Another provision of S. 2999 which causes independent producers concern is the section which exempts from price controls only the incremental oil production resulting from an enhanced oil recovery project. Clearly this provision would result in far less additional reserves and production than would be forthcoming under the price provisions of the Bentsen bill. It bears repeating that not only are the costs of these projects high, but the risks are great as well. Moreover, there is usually a substantial time lag between implementation of enhanced oil recovery techniques and production of the first incremental barrel. With some processes this lag can be as much as 1 to 3 years.

Therefore, given the high front end loan in addition to the risk and time factors attendant to these projects, it is essential that price relief be made available at the earliest possible opportunity, and in a manner that offers the most financial protection with the least administrative burden. Without price relief for all production from an enhanced oil recovery property, most producers, especially independent producers, would not find the economic incentive present to undertake these risky ventures.

Mr. Chairman, in closing I emphasize that the social benefits of encouraging maximum use of enhanced oil recovery techniques are many and the social costs are relatively few in comparison. The resultant increase in domestic reserves and production would reduce our growing and already unhealthy foreign energy dependence. This reduction in dependence would provide the United States with greater independence in the conduct of our foreign policy.

Crude oil would be produced that would otherwise be shut in and likely lost forever. This would lead to additional Federal, State, and local tax revenues being generated through increased collections of corporate, severance, royalty and property taxes. There would be no cost to the consumer because each additional barrel of oil produced will barrel-for-barrel reduce our imports of petroleum. If we fail to implement such a program what is the cost of not reducing our dependence on foreign petroleum? I do not know the specific answer, but I think that you will agree that it is a cost we cannot afford.

Thank you.

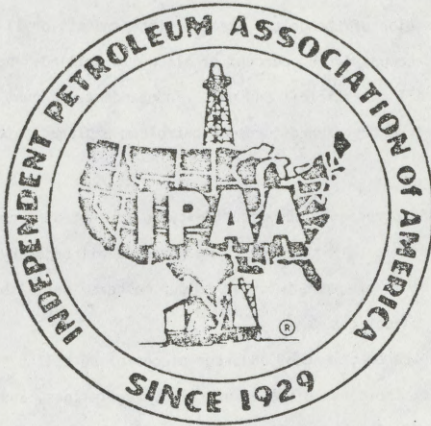
[The prepared statement of Mr. Russell follows:]

ORAL TESTIMONY OF

JAMES E. RUSSELL

FOR

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA



BEFORE THE

SENATE ENERGY COMMITTEE

INCENTIVES FOR TERTIARY ENHANCED RECOVERY
TECHNIQUES, CRUDE OIL PRODUCTION (S. 2623 AND S. 2999)

Testimony of James E. Russell, Chairman
IPAA Crude Oil Committee
Before the Senate Energy Committee
July 17, 1978

RE: Incentives for Tertiary Enhanced Recovery Techniques,
Crude Oil Production (S. 2623 and S. 2999)

I am James E. Russell and I appear before you today in my capacity as the Chairman of the Crude Oil Committee of the Independent Petroleum Association of America. I am also President of James E. Russell Petroleum, Inc. and Russell Engineering which are located in Abilene, Texas. I am a registered Professional Engineer in both Texas and Kansas, and I am a member of the National Society of Professional Engineers and the Society of Petroleum Engineers of AIME.

The Independent Petroleum Association of America (IPAA) is a national organization of some 5,000 independent oil and gas explorer-producers who operate in every producing region of the United States. Independents drill 90 percent of "wildcat" wells; account for 80 percent of all wells drilled; and produce about 40 percent of all domestic oil and gas. Independents account for over 40 percent of total industry expenditures on petroleum exploration and field development.

The IPAA appreciates the opportunity to present our comments and recommendations to this Committee regarding enhanced oil recovery legislation not just because it is of great interest to our members, but also because of the national energy implications.

Despite the enactment of numerous pieces of so-called "energy" legislation and the issuance of thousands of pages of rules, regulations, and orders by the Department of Energy, the United States continues to become increasingly dependent on foreign petroleum. Since 1972 domestic petroleum reserves have fallen by nearly one-fifth; domestic crude production has fallen by one-ninth; imports of crude and product have nearly doubled; and we have become six times more dependent on the 1973 Arab embargo participants for our petroleum supply. If these trends continue, then by 1980 we can expect that this nation will have to rely on imports

for two-thirds of our petroleum consumption, that we will be dependent on the 1973 Arab embargo participants for one-half of our petroleum imports, and that we will have an energy import bill in the neighborhood of \$90 billion per year.

These trends could be substantially lessened -- if not reversed altogether -- if federal energy policy were designed to actively encourage, rather than impede, the full development of all our vast domestic energy resources, including crude oil and natural gas. Although steps can -- and must -- be taken to eliminate wasteful uses of energy, there is only one way to reduce over the long run our growing reliance on high-cost supplies of insecure foreign energy: increase domestic energy production.

The IPAA applauds the efforts this Committee and Senators Bentsen and Hart are making to seek those positive incentives which are needed to maximize domestic energy production. Though there is some disagreement concerning the precise amount, the potential for increasing both the rate and ultimate total recovery of our crude oil resources through enhanced recovery techniques is universally acknowledged.

As a rule of thumb, current petroleum economics dictate that only one-third of the petroleum contained in a reservoir will ever be extracted by primary and conventional secondary enhanced recovery operations. It has been estimated that this will leave unrecovered nearly 300 billion barrels of oil in currently identified reservoirs. Thus, the need to expand enhanced oil recovery operations is obvious.

A study (the "Lewin Study") commissioned by the Federal Energy Administration (FEA) concluded that with market pricing more than 43 billion barrels of additional crude oil could be extracted from existing fields through enhanced oil recovery techniques. By 1990 this would add as much as 3 million

barrels per day to domestic production. However, the study also concluded that the existing crude oil price control system will prevent more than 90 percent of this potential production from ever being realized.

Similarly, a recent Office of Technology Assessment study found that if given current world oil prices, enhanced oil recovery techniques could add between 11 and 29 billion barrels of oil to existing domestic reserves. This could increase production by as much as 1 million barrels of oil per day in 1985, and as much as 1.7 million barrels per day in 1990.

Thus there is no doubt that if given market pricing now, enhanced oil recovery techniques could add significantly to domestic crude oil supplies in the very near future. And every additional barrel of domestic petroleum which is produced leads directly to one barrel less of petroleum imported.

The provision of additional price incentives for enhanced oil recovery has been under consideration by the Department of Energy (and its predecessor the FEA) for the last few years. Congress, in enacting the Energy Conservation and Production Act in 1976 (P.L. 94-385), fully recognized the enormous potential of these enhanced oil recovery operations and directed the President to provide additional price incentives for tertiary enhanced recovery techniques as soon as possible. Since then, hearings have been held, findings have been made, but no incentives have been granted. In August 1977 the FEA set forth in the Federal Register what it termed its basic decisions with respect to a tertiary recovery program which would "be implemented in final regulations to be issued in the near future." As of today the "near future" has still not arrived. Will it ever? Clearly, it is time for Congress to take the initiative and provide those incentives which it concluded two years ago are necessary to realize the full potential of enhanced oil recovery.

Mr. Chairman, let me preface my specific comments with respect to the two enhanced oil recovery bills currently before your Committee by saying that I consider any version of an enhanced oil recovery bill to be a "necessary evil." This is because it is primarily the legislatively enacted crude oil price control system that makes such legislation necessary: without price controls there would be less need for Congress to provide enhanced oil recovery incentives. It is evident that the solution to our current energy problem is really very simple; return to market pricing for energy.

In this respect, the IPAA fully endorses the concept underlying Senator Bentsen's bill, the Tertiary Recovery Incentives Act (S. 2623). This bill embodies the principles of market pricing by exempting from price controls all production from qualified enhanced oil recovery projects. It would bring to the full market price all petroleum produced from properties on which a qualified enhanced oil recovery process is being utilized by a simple and efficient mechanism. A property would not qualify for this exemption unless it could be demonstrated that the enhanced oil recovery project could be expected to increase production. We believe that allowing market economics, rather than arbitrary administrative regulations, to determine whether a particular enhanced oil recovery project is, or is not, economically feasible is a far superior approach. This avoids additional paperwork burdens which are already onerous. It would be reasonable to assume that if enhanced oil recovery price exemption is contingent on extensive reporting, many independent producers would be unable to participate.

Because of the enormous cost and risk of enhanced oil recovery projects, it is appropriate that federal price controls be suspended on all crude oil produced from the property, rather than just the incremental production as

Senator Hart proposes in his bill S. 2999. One study of enhanced oil recovery project risk found that on average only sixty percent of all waterflood projects prove successful. In States such as West Virginia and Pennsylvania, more than half of all waterflood projects are unsuccessful. And this is for an enhanced oil recovery technique which is considered almost standard operating procedure and which would not qualify for price exemption under the provisions of Senator Bentsen's bill, S. 2623. For those types of enhanced oil recovery projects which would qualify for exemption, this same study found that few ever prove successful. Given the cost of these projects, the failure rate exposes producers to substantial financial risk.

A particular modified waterflood project in Mississippi, for example, is expected to cost about \$5 million for the wells, polymer facilities, and the 3 million pounds of polyacrylamide additive. In the Rockies some enhanced oil recovery tests are alone costing up to \$50,000 per injection well. Exotic gas flooding projects are even more expensive; one project in East Texas is costing a company \$70 million.

Despite the enormous costs associated with enhanced oil recovery projects, independents are becoming more active in these activities. A recent survey indicates that about half of the modified waterflood projects in the U. S. are implemented by independents. In California, an increasing number of independents are using steam injection to augment their production. For the other more exotic and more expensive enhanced oil recovery projects, the inherent risk coupled with the current absence of any price incentives has up to now precluded full participation by all but the very largest of independents. It is clear that removing price controls on enhanced oil recovery production would bring many of these projects within the grasp of smaller independents.

While IPAA greatly appreciates the interest and efforts of Senator Hart to encourage participation in enhanced oil recovery projects, especially by independent oil producers, we do have reservations about certain aspects of his legislation, the Enhanced Oil Recovery Commercialization Act of 1978 (S. 2999).

One of the distinguishing features of S. 2999 is the loan guarantee provision. This would provide a maximum of \$200 million in loan guarantees for qualifying "commercial demonstration" projects for new and improved methods of enhanced oil recovery on a fieldwide basis. If Congress should deem it necessary and appropriate to provide loan guarantees -- a course of action that I am not recommending -- then guarantees should be provided for the implementation of enhanced oil recovery technology, not the development of the technology. For the most part, the average independent producer does not have the staff, expertise, or resources to engage in large, highly technical, and complex enhanced oil recovery research and development activities. And the provision of a guaranteed \$25.00 per barrel for production from a "first of a kind" enhanced oil recovery project would not be of much assistance to independent producers.

In light of the extremely high costs associated with many of the more sophisticated types of enhanced oil recovery projects, it is unlikely that \$200 million would be sufficient to benefit many projects. Rather, it is more likely that \$1 billion to \$10 billion would be required to stimulate significant results.

Since loan guarantees reduce the cost of borrowing (in some cases making borrowing possible) but do not reduce the inherent engineering risk, independent producers will still be reluctant to undertake risky enhanced oil recovery projects that expose them to financial ruin. Therefore, if such a program is implemented, the loan guarantees should have as collateral only those resources involved in the enhanced oil recovery projects, and should not place the independent's entire net worth at stake.

Finally, the conditions that must be satisfied to qualify for a loan guarantee under S. 2999 would probably prevent most independent producers from taking advantage of the program. The requirement that independents own sixty percent of the working interest of the field in order to qualify for the enhanced oil recovery loan guarantees will severely restrict the effectiveness of the program. In this respect, it should be noted that unlike the Bentsen bill which applies to enhanced oil recovery projects on a property basis, the Hart bill is more restrictive in that it applies to projects on a field basis. Furthermore, most independent producers simply could not afford to wade through the lengthy and burdensome process of applying for the loan guarantee. As I have already indicated, reduced or delayed cash flow already presents a tremendous obstacle to independent producers. The additional time and cost involved in the loan guarantee application procedure would merely compound this problem, not solve it. Therefore, these two considerations alone likely would prevent all but the largest independents from participating.

Another provision of S. 2999 which causes independent producers concern is the section which exempts from price controls only the incremental oil production resulting from an enhanced oil recovery project. Clearly, this provision would result in far less additional reserves and production than would be forthcoming under the price provisions of S. 2623. It bears repeating that not only are the costs of these projects high, but the risks are great as well. Moreover, there is usually a substantial time lag between implementation of enhanced oil recovery techniques and production of the first incremental barrel. With some processes, this lag can be as much as one to three years.

therefore, given the high front end load in addition to the risk and time factors attendant to these projects, it is essential that price relief be made available at the earliest possible opportunity and in a manner that offers the most financial protection with the least administrative burden. Without price relief for all production from an enhanced oil recovery property, most producers (especially independent producers) would not find the economic incentive present to undertake these risky ventures.

The IPAA is pleased that the legislation offered by Senators Bentsen and Hart contain administrative provisions which recognize and defer to the special expertise and experience of state regulatory authorities. We sincerely hope that any legislation that is eventually enacted will retain this feature.

Although Senator Hart's Enhanced Oil Recovery Tax Act of 1978 (S. 3000) is not within the specific jurisdiction of this Committee, we nevertheless would like to endorse the tax provisions contained in it. Enabling producers to expense, rather than amortize, expenditures incurred for enhanced oil recovery production will stimulate investment in these projects by helping to offset some of the high front end load.

Before I present my concluding remarks, Mr. Chairman, I would like to bring to the attention of the Committee that the Department of Energy is currently considering entitlements changes which if implemented will doom many existing enhanced oil recovery projects. On April 21 of this year, the Economic Regulatory Administration of the Department of Energy proposed to place entitlements obligations on lower tier crude oil used by producers as lease fuel. Producers use crude oil on their lease primarily for enhanced oil recovery projects, most notably steam drive injection and cyclic steam injection. These techniques are used extensively in California where much of the crude produced is low gravity. The proposed entitlements change would in effect penalize producers \$6.50 for

every barrel of lower tier crude they use as lease fuel. It should be noted that this penalty is more than the federal crude oil price control regulations allow producers to sell this crude for! A copy of IPAA's testimony to ERA regarding this proposed entitlements change is attached to my written testimony and I respectfully request that it be entered into this hearing record.

The IPAA shares the Committee's interest in seeking means to maximize domestic crude oil production. Enhanced oil recovery projects can make a substantial contribution to domestic production and should be encouraged to the maximum extent practicable. IPAA believes that the goal of maximizing domestic production can be achieved most effectively through those programs which are the least complicated and impose the least administrative burden from the standpoint of both government and industry.

Mr. Chairman, in closing I emphasize that the social benefits of encouraging maximum use of enhanced oil recovery techniques are many and the social costs are relatively few in comparison. The resultant increase in domestic reserves and production would reduce our growing and already unhealthy foreign energy dependence. This reduction in dependence would provide the United States with greater independence in the conduct of our foreign policy. Crude oil would be produced that would otherwise be shut in and likely lost forever. This would lead to additional federal, state, and local tax revenues being generated through increased collections of corporate, severance, royalty, and property taxes. There would be no cost to the consumer because each additional barrel of oil produced will barrel-for-barrel reduce our imports of petroleum. If we fail to implement such a program, what is the cost of not reducing our dependence on foreign petroleum? I do not know the specific answer, but I think that you will agree that it is a cost we can not afford.

WRITTEN TESTIMONY

OF

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

AND ON BEHALF OF

CALIFORNIA INDEPENDENT PRODUCERS
ASSOCIATION
KANSAS INDEPENDENT OIL AND GAS
ASSOCIATION
KENTUCKY OIL AND GAS ASSOCIATION
LIAISON COMMITTEE OF COOPERATING
OIL AND GAS ASSOCIATIONS
LOUISIANA ASSOCIATION OF INDEPENDENT
PRODUCERS AND ROYALTY OWNERS
MICHIGAN OIL AND GAS ASSOCIATION
NORTH TEXAS OIL AND GAS ASSOCIATION
OKLAHOMA INDEPENDENT PETROLEUM
ASSOCIATION
PENNSYLVANIA GRADE CRUDE OIL
ASSOCIATION
INDEPENDENT OIL PRODUCERS
TRI-STATE, INC.

PENNSYLVANIA OIL, GAS AND MINERALS
ASSOCIATION
PERMIAN BASIN PETROLEUM ASSOCIATION
NATIONAL STRIPPER WELL ASSOCIATION
TEXAS INDEPENDENT PRODUCERS AND
ROYALTY OWNERS ASSOCIATION
WEST CENTRAL TEXAS OIL AND GAS
ASSOCIATION
OHIO OIL AND GAS ASSOCIATION
ILLINOIS OIL AND GAS ASSOCIATION
INDEPENDENT PETROLEUM ASSOCIATION
OF MOUNTAIN STATES
PANHANDLE PRODUCERS AND ROYALTY
OWNERS ASSOCIATION
THE LAND AND ROYALTY OWNERS OF LOUISIANA

BEFORE THE

DEPARTMENT OF ENERGY, ECONOMIC REGULATORY ADMINISTRATION

INCLUSION OF NONREFINING USES OF LOWER TIER
CRUDE OIL WITHIN THE ENTITLEMENTS PROGRAM

MAY 26, 1978

Written Comments by
Independent Petroleum Association of America, et al.
RE: "Inclusion of Nonrefining Uses of Lower Tier
Crude Oil Within the Entitlements Program"
(43 Fed. Reg. 16987, 4/21/78)

May 26, 1978

The Independent Petroleum Association of America (IPAA) is a national trade association representing some 5,000 independent explorer-producers of crude oil and natural gas who operate in every producing region of the United States. IPAA members are deeply disturbed about the Economic Regulatory Administration (ERA) proposal to extend the entitlements program to certain nonrefining uses of crude oil, particularly to uses of crude oil in an oil or gas producing operation.

The implementation of this proposal would have severe consequences, including the following:

1. Substantial volumes of oil production would be shut in and millions of barrels of reserves would be lost forever. Subjecting production uses of crude oil to the entitlements program would directly increase the cost of such crude oil by an amount more than its price, thereby significantly raising operating costs, and drastically shortening the economic lives of many operations.
2. Exploration and development expenditures would be curtailed, thus causing less new oil and gas to be found and produced. Affected producers would incur a direct financial loss. Since ceiling price regulations prevent cost pass-through, producers would either have to forego profit on those operations made uneconomic by this proposal, or needlessly have to divert financial resources from other planned investment programs to pay the entitlements costs.
3. The complexity of the already complex entitlements program would be increased significantly, and it would be extended to thousands of

producers and an even greater number of relatively insignificant transactions. Small producers would find the reporting and compliance burdens enormous; and so would ERA.

Such consequences are not in the National interest and would contravene the Administration's energy and regulatory goals. Therefore, IPAA recommends that ERA abandon this counterproductive and ill-conceived idea. Producer uses of crude oil should not be included in any subsequent rulemaking proposal to extend coverage of the entitlements program. Furthermore, this policy decision should be announced by ERA as quickly as possible.

DOE must not proceed with this proposal until all facts are known. In a letter dated April 26, 1978, IPAA officially requested an extension of the comment period and the dates for hearings on this rulemaking. Just a few days before the first hearing, IPAA received what was believed to be official notice that our request for postponement of the hearings had been denied but that a 30-day extension to the comment period had been granted. Later we were told that the 30-day extension had been reduced to 8 days; no reason was given. These decisions violate at least the spirit, if not the letter, of the President's Executive Order No. 12044, "Improving Government Regulations."

An extension would have allowed us more time to assess and document more fully the impact of ERA's proposal on our members' operations. We believed ERA would want to have this information before continuing with its rulemaking process and would not want to propose a regulation which would cause significant production and reserves losses. In almost all matters, and especially in complex ones like entitlements changes, a reasonable amount of time is needed for us to disseminate information on ERA's proposals to our members, for them to individually evaluate and assess the potential impacts and convey their thoughts to us, and then in turn for us to compile all the varied responses into a final analysis.

Had our requests been granted, IPAA would have attempted to assemble quantitative data on the costs and the potential production and reserves losses. Before proceeding further in this rulemaking it is essential that ERA now assemble this information and fully investigate its potential ramifications. In fact, such an analysis is required by Section 3 of Executive Order No. 12044. Once this occurs, we are confident ERA will recognize its detrimental consequences.

Crude oil is used in oil and gas producing operations in a number of ways.

The largest volume use is in conjunction with thermal recovery operations where crude is burned under a boiler to create hot water or steam for injection. Crude is sometimes used as fuel for heater-treaters and other lease equipment requiring the application of heat. Crude oil could also be used as the carrying fluid in some more sophisticated enhanced recovery technologies. Other uses of crude oil in production which would likely come within the purview of these proposed regulations would be its use in well stimulation and fracturing, as an additive in drilling mud, in coring operations, and in well completions. While these latter types of uses are quite common, they typically involve changing locations and relatively small volumes at any one time.

In any of the above situations, the crude involved could either be produced from the lease on which it is used or be produced on some nearby lease and purchased for the operation in question. In either case the crude is valued for the particular use at its ceiling price which is the maximum the producer could have received had he sold the crude instead.

The proposed extension of entitlements to producer uses of crude oil is both onerous and perverse. Unlike refiners and resellers, producers would be blocked by the ceiling price regulations from passing through the entitlements costs. This would force them to absorb the full impact of this proposal. They would incur a dollar loss for every dollar spent for entitlements.

Producers are generally using their own crude oil. The ceiling price regulations already deny producers the revenues they appropriately should be receiving for their crude. This proposal would require them to pay others (i.e., buy entitlements) for the right to use their own production when they are not permitted to sell it at an equivalent price. This would place producers in an untenable position because neither could they afford to use their own crude nor would they have sufficient funds to purchase replacements.

This proposed extension of entitlements would have two highly negative impacts on production and reserves:

1. As a result of substantially increased costs for affected operations, economic lives would be shortened. Some operations would be shut in immediately.
The thermal recovery operations would be affected most. A large volume of heavy crude is produced by thermal projects which already face high operating costs and low prices; this more than doubling of the fuel costs would likely make them uneconomic. It simply would make no sense to raise artificially the operating costs of this low gravity production when to do so would result in the loss of considerable production and reserves. Similarly affected would be all other operations where crude oil is or might be used.
2. Producers affected by this proposal would not have as much capital available for exploration and development. They would either shut in affected operations or continue them, but incurring substantially higher costs. For those shut in, existing profits would be lost forever; for those continued, the entitlements costs would reduce profits dollar-for-dollar. Either way, producer net revenues would be

decreased and there would be less capital available for new exploration and development efforts elsewhere. Relationships between wellhead revenues and investment in exploration and development are well established. There can be little doubt that the removal of substantial funds from the producing industry will lessen future activity.

Administrative, compliance and reporting burdens would be enormous. The extension of the entitlements program to the use of crude oil by producers would greatly increase the administrative, compliance, and reporting burdens of ERA and producers. Because of the large number of relatively small volume uses of crude oil by many producers, ERA would face difficult problems in expanding the entitlements program to include these additional firms and transactions. Can you imagine the monthly entitlements notice containing several thousand firms -- many with minimal purchase requirements. Special new reports would be required of all 10,000-12,000 producers to make certain all uses are covered whenever and wherever they occur; presumably these would have to be processed monthly by ERA. Compliance and policing of the entire program would be a nightmare. With all these difficult problems, one wonders whether the costs are worth the benefits derived. Since there are no benefits, the conclusion is obvious.

IPAA would now like to respond to several of the comments and questions included in the Federal Register notice.

1. ERA stated (43 Fed. Reg. 16988), "...we have tentatively concluded that, as a general proposition, nonrefining uses should be brought within the entitlements program."

Such a conclusionary statement before even the first stage of the rulemaking process is extraordinary. Furthermore, just proposing such an action with regard to production uses creates substantial uncertainty. How can those producers who might be affected make

investment decisions and plan their operations when these projects could be made uneconomic by ERA at the stroke of a pen? Including production uses of crude oil in the entitlements program is so obviously illogical and counterproductive that it should never have been proposed at all.

2. "Alternative Proposal as to Producers" (43 FR 16998) suggests exempting "the use of lower tier crude oil by producers for the purpose of increasing production."

If this rulemaking is continued into the second stage, ERA should make clear that production uses of crude oil will not be included. This exemption should be defined broadly enough so that all possible producer uses, like the ones previously described, are exempt.

The ERA has recognized the similarity between the entitlements program and the proposed Crude Oil Equalization Tax (COET). The House version of COET, which is the only one that has passed either Body, expressly excludes from the tax "the use of crude oil in the extraction of crude oil, natural gas, or natural gas liquids." (Sec. 4988 (c) (3) of HR 8444, as passed by the House). The House of Representatives recognized the obvious consequences of taxing crude oil used in production; so should ERA.

3. ERA concluded (43 FR 16987) that "non-refining uses of lower tier crude oil . . . confer a windfall on certain end-users. . ."

(emphasis added)

Enough has been said in this regard. Since producers cannot pass through increase costs and are not able to sell such crude oil at the upper tier or free market price, the statement is inflammatory and inaccurate on its face. It must be retracted.

- 6 -

4. In discussing the Alternative for producers (43 FR 16988) the ERA states, "The inclusion in the entitlements program of crude oil used by producers for the purpose of enhancing production may increase the cost of some domestic production and thus tend to reduce the amount of such production. Our proposals in this notice might therefore be considered as inconsistent with DOE's policy of encouraging enhanced domestic production."

The only problem with ERA's analysis is understatement. The proposal will "increase the costs", will "reduce the amount", and will be "inconsistent with DOE's policy. . ." All uses of crude oil to increase production of crude oil, natural gas, or natural gas liquids should be exempt from entitlements regardless of where produced and from whom purchased.

5. Comments (43 FR 16989) concerning disadvantages to refiners who might otherwise sell residual fuel oil to producers for fuel ignore the pass through problem of producers and miss the nature of the real entitlements problem.

Producers have always used crude oil in the producing operation and should continue to have the right to do so. Producers should not be forced to buy lease fuel at high prices when they are not permitted to sell their crudes at market prices.

Because many small producers would have to shut in a substantial share of their production and could go out of business, competition in the production sector would be reduced under this ERA proposal. The requirements of Sec. 4(b)(1)(F) of the Emergency Petroleum Allocation Act should be given no more weight than those of Sec. 4 (b)(1)(D). The latter requires the "preservation of an economically sound and competitive petroleum industry, including the priority needs to restore and foster

competition in the producing . . . industry. . ."

Considering the variety of uses of crude in production and the inadequacies of ERA's tertiary incentive program, relying on that tertiary program to restore lost revenues would not be an acceptable alternative.

Refiners who would attempt to market resid to producers for lease fuel would largely be located in the heavy oil areas where crude prices are already low. It is well known that the current entitlements program places an inequitably heavy burden on the lower gravity and quality crudes. Making fundamental revisions to the entitlements program so that entitlements values would reflect individual crude oil grade, quality, and location would dramatically improve the marketability of products typically refined from lower gravity crudes.

Summary

The real problem ERA should be trying to solve is the national energy problem. Fundamental changes in ERA policy and approach will be necessary if our energy problems are to be solved. Our national policy should be designed to provide maximum incentives to increase production. The elimination of price controls on crude oil on their current expiration date would provide those incentives. ERA's approach should be to move forward aggressively on removing to the fullest extent permitted by law the disincentives for increased production which currently exist in the regulations; new disincentives are not needed.

ERA should quit this counterproductive, nuisance-like tinkering with its regulations and get on with the job of implementing sound energy policy. To do otherwise causes uncertainty, reduces exploration, development, and production activities, and worsens our national energy problem.

Senator BARTLETT. Mr. Russell, I have one question I will ask now and possibly submit some others.

If both secondary and tertiary were deregulated, what would be the respective returns on investment of each of them? If you can't give that now, could you give that for the record?

Mr. RUSSELL. If they were both released, what would be the——

Senator BARTLETT. Yes. If it went to the world price, what would be the respective returns on investment?

Mr. RUSSELL. I am afraid it would be impossible for me to give you a substantive answer now.

Senator BARTLETT. Could you give one for the record?

Mr. RUSSELL. I think I could.

Senator BARTLETT. All right. I ask that of other witnesses, also.

I thank you very much, Mr. Russell.

Mr. Cooper, would you have any questions?

Mr. COOPER. No.

Senator BARTLETT. The record will be open for 2 weeks and you can expect to receive questions from various members of the committee.

I thank all the witnesses. I think the testimony was very helpful and beneficial and we will enjoy going through the written testimony in greater length, and undoubtedly there will be questions forthcoming.

The hearing is adjourned.

[Whereupon, at 12:54 p.m. the hearing was adjourned.]

APPENDIX

ADDITIONAL MATERIAL SUBMITTED FOR THE RECORD

EXECUTIVE OFFICE OF THE PRESIDENT,
OFFICE OF MANAGEMENT AND BUDGET,
Washington, D.C., July 26, 1978.

HON. HENRY M. JACKSON,
Chairman, Committee on Energy and Natural Resources, U.S. Senate, Washington, D.C.

DEAR MR. CHAIRMAN: This is in response to your request of July 6, 1978, for the views of this Office on S. 2623, a bill "To provide for increased petroleum production in the United States through the use of incentives for tertiary recovery processes."

In testimony before your Committee on July 17, 1978, the Department of Energy explained its reasons for recommending against favorable action on the bill. We concur in the views expressed in the Department of Energy testimony and, accordingly, recommend against the enactment of S. 2623.

Sincerely,

NAOMI R. SWEENEY,
Acting Assistant Director for Legislative References.

AMERICAN PETROLEUM INSTITUTE,
Washington, D.C., July 17, 1978.

HON. HENRY M. JACKSON,
*Chairman, Senate Energy and Natural Resources Committee,
Dirksen Senate Office Building,
Washington, D.C.*

DEAR MR. CHAIRMAN: The American Petroleum Institute in conjunction with the Rocky Mountain Oil and Gas Association and the Western Oil and Gas Association is pleased to submit the following statement in support of S. 2623, "Tertiary Recovery Incentives Act".

We would appreciate your including the attached statement in the record of the committee's hearings on this subject on July 17, 1978.

Sincerely,

FRANK N. IKARD.

STATEMENT ON BEHALF OF THE AMERICAN PETROLEUM INSTITUTE, ROCKY MOUNTAIN OIL & GAS ASSOCIATION, AND THE WESTERN OIL & GAS ASSOCIATION

The American Petroleum Institute (API), a national trade association representing all sectors of the domestic petroleum industry, has reviewed proposed bill S. 2623, "Tertiary Recovery Incentives Act." The API in conjunction with the Rocky Mountain Oil & Gas Association (RMOGA) and the Western Oil and Gas Association (WOGA) wishes to submit favorable comments and requests that these comments be made a part of the hearing record.

The United States has significantly large, known deposits of oil in place which cannot be recovered profitably under current economic conditions. This involves approximately three hundred billion barrels of oil whose location and general characteristics are known but which cannot be produced by current technology at existing prices. Production of this vast potential could significantly reduce the nation's dependence on foreign energy sources. In fact, the recovery of just 10 percent of these resources would equal the current known reserves of the entire United States, including Alaska. But this can only be done through expensive enhanced oil recovery process.

Enhanced oil recovery processes may be generally classified as thermal, gas miscible, and chemical. At current, controlled prices for crude oil, only a limited portion of the opportunities for thermal process can be economically justified. California is the principal producing area where these applications have been undertaken. Yet, even there, rigid environmental standards are effectively preventing any appreciable expansion of this activity.

If the total production from enhanced projects were exempted from price controls, we believe there would be significant economic incentive to institute enhanced recovery techniques and processes in numerous areas of the United States. Furthermore, a simplified authorization system, with assurances that regulations would not be expanded or adversely changed after recovery projects are initiated, would provide additional production incentives.

With these incentives, and with the assumptions made by the National Petroleum Council, it is estimated that the country could increase its recoverable reserves by 25 billion barrels of oil and achieve a production rate of three million additional barrels per day in 1990. However, time is an important consideration in meeting these goals.

Every day a significant portion of the target in-place oil is moving beyond the reach of enhanced oil recovery processes. This diminishing potential is the result of well abandonments dictated by current pricing controls. The controls prevent the generation of sufficient revenues to offset the ever rising costs of producing from marginal wells.

The large potential of enhanced oil recovery in the United States demands a significantly different economic and regulatory climate than that which currently exists.

To create the proper climate, the total production from enhanced recovery projects needs to be freed from price controls. Alternate proposals that call for decontrolling only the incremental barrel of enhanced oil recovered, would not provide the needed incentive. Enhanced recovery processes require very large front-end capital investments and long lead times. Any proposal that would provide higher prices only for a portion of the oil recovered—the incremental barrel—would be insufficient incentive to justify the inherent risk of failure of the recovery project itself.

Additionally, providing higher prices only for the incremental barrels produced would require that a determination be made between the number of "enhanced" barrels and the number of "non-enhanced" barrels recovered. In our judgment, it would be virtually impossible to make such a determination.

We have for some time been on record in favor of exempting enhanced recovery projects from price controls or limitations. Specifically, in testimony we presented on the National Energy Plan in May and September 1977 before, respectively, the House Committee on Ways and Means and the Senate Committee on Finance, we stated that the exemption for enhanced recovery projects is the best means of ensuring maximum recovery of oil from existing fields.

We further propose that certification of enhanced recovery projects as bona fide should be subject to a simplified authorization system, such as the state regulatory agencies. This also would require a guarantee that the relief granted from the composite price limitations of the Energy Policy and Conservation Act (EPCA) would not be rescinded except for fraud or failure to institute the program.

In the event these incentives are made available, we are confident that the nation would achieve the oil reserves and production estimates cited by the NPC. We believe that the proposed legislation, S. 2623, will provide such incentives. Ultimately, this would result not only in decreased dependence on foreign energy sources, but in all likelihood a stronger U.S. economy.

The API, RMOGA and WOGA appreciate the opportunity to comment favorably on the Tertiary Recovery Incentives Act, and wish to express our support of the measure.

SUPPLEMENTAL STATEMENT OF THE WESTERN OIL AND GAS ASSOCIATION ON S. 2623

The Western Oil and Gas Association, the industry trade association representing 90 percent of all petroleum production, refining and wholesale marketing in the seven western states, strongly supports S. 2623. We believe its three major provisions are essential to the national interest in that they would provide the much needed stimuli for increasing oil production from known oilfields.

Normally, oil wells in the United States under conventional methods recover only one-third of the original oil in place in an oil field, leaving the remaining two-

thirds in the ground. These barrels left in the ground make an inviting target for augmenting domestic oil reserves and argue strongly for production incentives to encourage the onset of tertiary recovery processes.

The first and most essential provision of S. 2623 provides for price decontrol of all oil produced from a property or collection of properties utilizing one of the approved tertiary recovery processes. Price decontrol of incremental oil alone would be inadequate and lead to constant disputes as to what oil is tertiary and what would have been produced under ordinary circumstances. More importantly, without this provision, there would be insufficient incentive to stimulate action on tertiary production. Further, with respect to this provision, we believe that adequate recovery incentives must be furnished equitably to all producers, and the decontrol provision must include all oil produced from a property rather than only incremental oil.

The second provision of the bill, that oil once decontrolled cannot be suspended without a clear demonstration of fraud or lack of diligence by participating producers, is also important. A producer needs the necessary assurances that the rules will not be changed after he has undertaken the large and risky investments necessary to start tertiary recovery methods. In most cases, new tertiary recovery projects do not produce oil immediately, as it normally takes several years to bring a tertiary project into production after it is once started. Thus, if the producer is continuously vulnerable to arbitrary government rule making in addition to all the other risks inherent to oil production, he may not choose to start the project.

Likewise, an incentive plan should protect the producer from being penalized with a lower price for existing production. We believe this is accomplished in the third provision of the bill by excluding the decontrolled oil from the composite price. Without this provision the producer would find himself simply shifting money from one pocket to another.

The subject of tertiary recovery has been studied in detail several times since 1975. The principal studies, which were conducted on a reservoir-by-reservoir basis, were the two studies by Lewin & Associates for the FEA and ERDA; the National Petroleum Council study of December 1975; and the Office of Technology Assessment study of January 1978. These studies examined the potential for tertiary recovery and the incentives needed to commence tertiary projects. They all showed that the potential for tertiary recovery was substantial and that price relief constituted the most effective incentive to realize this large potential at the earliest date.

Passage of S. 2623 will have an immediate effect on tertiary production already underway in the Western United States, particularly in California where thermal methods are already being used. Steam flooding can be accelerated and provide a positive addition to the nation's crude supply.

On a longer time scale, some of the processes that involve more technical risks such as carbon dioxide injection or chemical injection will be undertaken. The establishment of strong incentives now will give the producer confidence in making the large and risky investments for those processes. The producer also will defer the abandonment of target reservoirs that may be abandoned if no incentive is anticipated.

The prospective abandonment of not only individual reservoirs but also entire oilfields is a matter of particular concern and forms the principal basis for advocating the adoption of S. 2623. Many oilfields in the United States are declining in their production toward their economic limit. Once these fields reach that point, production will cease, wells will be abandoned, and leases surrendered. As a result, oil which might be produced under enhanced recovery projects, started in the waning stages of ultimate depletion, will be lost forever.

Presently, the two major roadblocks in tertiary recovery are technical risks and economic risks. The industry and the Department of Energy have an extensive program of research and field demonstration underway to help reduce the technical risks of tertiary recovery processes. This effort, however, will have little impact on the use of the more expensive processes, unless the petroleum industry can expect an adequate economic return. The provisions of S. 2623 would make strong contributions to reducing economic risks and would complement the technical effort of industry and DOE.

In summary, we urge the passage of S. 2623 and believe it would be an effective means for removing the current roadblocks to extensive tertiary oil recovery efforts and their contributions to the nation's crude supply.

GETTY OIL Co.,
Los Angeles, Calif., July 27, 1978.

HON. HENRY M. JACKSON,
*Chairman, Senate Energy and Natural Resources Committee,
Dirksen Senate Office Building, Washington, D.C.*

DEAR MR. CHAIRMAN: These brief remarks are in support of S. 2623, the Tertiary Recovery Incentives Act and are submitted for the record. S. 2623 is a sound piece of legislation that is deserving of passage.

Because this legislation moves away from direct regulation toward a free market solution, it is an important step in providing equitable pricing and adequate economic incentives for enhanced production. However, price relief for the enhanced recovery of crude oil should not penalize other categories of domestic oil production. A less restrained market is essential if oil companies are to continue expansion of existing projects and further develop new tertiary programs.

The suspension of ceiling price controls on crude oil recovered by the tertiary recovery process will certainly result in increased production and greater recoverable reserves. Also, the life of many existing projects would be extended.

The bill should be altered slightly in only one instance. Section 20(a) defines the kinds of recovery methods which qualify as tertiary recovery processes. Ordinary water flooding is considered neither a primary or tertiary technique. Apparently, that is also the intent of the bill. To prevent the possible misinterpretation of the legislation and insure the exclusion of water flooding as a tertiary technique, the following language change is suggested. On line eight of page two after the word "occur", strike out the balance of the sentence and add the following language: from the preceding phase of development, whether primary or secondary recovery. For the purposes of this act, ordinary water flooding is not to be considered a "tertiary recovery technique".

With the decontrol of all tertiary oil, by legislation or regulation, there is no need for loan guarantees or tax incentives in attempting to make tertiary recovery more attractive. Inasmuch as S. 2999 limits the amount of loan guarantees to \$200 million and the qualified applicants to very small companies, it is doubtful whether this bill will have any beneficial effect on the enhancement of tertiary recovery techniques, given the immense amounts of capital necessary for the development and implementation of those techniques.

S. 3000 would be of little value. The Internal Revenue Code currently allows deductions for intangible drilling costs, materials and supplies used in secondary and tertiary recovery. The proposed Section 615 adds no significant deductions for people or companies using tertiary techniques.

Sincerely,

HAROLD E. BERG.

ATLANTIC RICHFIELD Co.,
Washington, D.C., July 31, 1978.

HON. FLOYD K. HASKELL,
*Energy and Natural Resources Committee,
Dirksen Senate Office Building,
Washington, D.C.*

DEAR SENATOR HASKELL: Attached is Atlantic Richfield Company's statement pertaining to needed incentives for enhanced oil recovery (EOR) for inclusion in the record of the July 17, 1978 hearing of the Energy and Natural Resources Committee.

Atlantic Richfield is a pioneer in the field of enhanced oil recovery and has been vigorously active in the field for more than a quarter century. This is borne out by the fact that the first of many patents which the Company has obtained in enhanced oil recovery technology was issued in September 1952 as a result of extensive research work completed prior to that time. The Company's interest in enhanced oil recovery has never been as high as it is today. We are very enthusiastic about the potential of the carbon dioxide miscible injection process, particularly in selected fields in the Permian Basin of West Texas, an area in which Atlantic Richfield has very important interests. However, our excitement and enthusiasm is severely dampened by the knowledge that realization of the carbon dioxide miscible injection EOR potential is contingent upon the availability of adequate incentives. Senate Bill 2623 would provide the needed incentives, and Atlantic Richfield urges its adoption.

We appreciate the opportunity which you and the Energy and Natural Resources Committee have afforded Atlantic Richfield and others to present views on incentives for enhanced oil recovery for consideration by the Senate in dealing with this very important issue.

Sincerely,

HOLLIS M. DOLE.

STATEMENT OF ATLANTIC RICHFIELD CO.

Atlantic Richfield is very interested in the subject of enhanced oil recovery. Our experience in research and application of high oil recovery processes dates back to September 1952 when the Company patented the High Pressure Gas Miscible Process—a method which was first implemented in our Block 31 Field, Crane County, Texas, one month later. Since September 1952, Atlantic Richfield has obtained 53 patents in enhanced recovery technology and has conducted and participated in numerous field tests using these and other exotic recovery techniques.

According to the API [1], as of the end of 1977, there have been discovered in the United States an estimated 450 billion barrels of oil, of which about 115 billion barrels have been produced, with remaining proved reserves of about 30 billion barrels. This means that about 305 billion barrels of already discovered oil are expected to be left unrecovered based on current technology and current economic conditions.

Certainly we cannot produce all of this, but if only 25 percent (76 billion barrels) could be recovered, the increase would equal the current reserves of the Western Hemisphere, and if only 10 percent (30 billion barrels) were recovered, it would approximate the current reserves in the United States.

During the last few years, various studies have been made to estimate how much of the total target of 304 billion barrels might be recovered under various assumptions of oil price, process efficiency, and return on investment. Results of the two most recent and most comprehensive studies [2, 3] are summarized in Exhibit No. 1. Other studies [4, 5, 6] have estimated enhanced oil recovery potentials of from 7 to 76 billion barrels. The estimates are not directly comparable because of differences in assumptions in the factors mentioned above, but they do show that there is a significant potential for enhanced oil recovery and that potential is very dependent on oil price.

These studies also addressed the potential producing rates of enhanced oil recovery projects. The estimates ranged from 0.3 to 1.7 MMBOPD in 1985 and 0.3 to 3.5 MMBOPD in 1990. These wide variations are also due to the differences in assumptions of oil price, process efficiency, and return on investment plus the fundamental difficulty in estimating the timing and magnitude of responses to relatively untried processes.

Although the potential reserves and producing rates of enhanced recovery oil are uncertain, it is our opinion that under current domestic oil price policy except for a small amount of thermal oil essentially no enhanced recovery oil will ever be produced.

No part of these 304 billion barrels will be either easy or inexpensive to recover. For the most part, this unrecoverable oil is left as residual saturation to water drives and waterfloods. Much of this oil is trapped in tiny pores in the rock and is surrounded by water. Some of it is left as a thin film coating the rock. Other oil is trapped in dead end passages and around the edges of the reservoir where it is very difficult for the driving fluids to reach. Since oil and water do not mix, a tension exists wherever oil and water come in contact. This inter-fluid tension serves to hold the oil in the rock and prevent it being recovered. Also being left is an appreciable amount of heavy oil which is very viscous and is in reservoirs which have little natural energy.

The enhanced recovery processes are designed to overcome these viscous and inter-fluid forces and have been categorized as thermal, gas miscible, and chemical. The thermal methods (cyclic steam injection, steam drive, and in situ combustion) heat the oil so it can flow more freely. The gas miscible processes (hydrocarbon gas and carbon dioxide injection) and the chemical surfactant processes create a miscible phase between the oil and the water, thereby overcoming the interfluid tensions.

This target of potentially recoverable oil beyond that which can be economically recoverable by conventional primary and secondary methods is referred to as both "tertiary oil" and "enhanced oil." Strictly speaking, there is a difference in that "enhanced oil" is more encompassing. But as most of the "enhanced oil" which seems to be achievable is "tertiary oil," the terms are used here interchangeably.

The thermal processes are already undergoing widespread application in heavy oil reservoirs where primary recovery is low and conventional secondary recovery methods are ineffective. The technology of thermal recovery is well advanced. Additional applications are being restrained more by environmental restraints than by technology or oil price limitations, but oil price improvements would help solve the environmental problems.

Carbon dioxide miscible injection has been used successfully in a few fields as a secondary recovery process and is currently being tested in pilot operations as a tertiary process. We know this process will displace waterflood residual oil, but we do not know how well or how fast. Nevertheless, the injection of CO₂, with or followed by water injection, appears to have a large potential for increasing recovery from previously waterflooded reservoirs. The Permian Basin of West Texas is an area where conventional waterflooding has been quite successful, but waterflooding will still leave about 56 billion barrels of oil unrecovered. The CO₂ miscible process appears to be very amenable to these reservoirs and could yield over 5 billion barrels of tertiary oil from this region alone. Restraints in CO₂ application are twofold—a limited supply of CO₂ and oil price controls. The potential 5 billion barrels of tertiary oil in the Permian Basin will require in excess of 30 trillion cubic feet of CO₂. Thus far the best sources appear to be natural occurrences in Southern Colorado and Northern New Mexico where a total of 5 to 10 TCF of CO₂ have been found. With adequate oil price incentives, these sources can be developed and the CO₂ transported by pipelines to the Permian Basin oil fields. Additional CO₂ exploration is continuing. Another source will be coal gasification plants, provided these are built in time. So although CO₂ is a problem, it appears to be solvable provided the second restraint—inadequate oil price—can be overcome.

The third type of enhanced oil recovery process, chemical flooding, has the advantage of not requiring exploration and transportation of a scarce injection fluid, but the injected chemicals must be specifically designed for each application, are expensive, and are subject to destruction by the reservoir environment. In our opinion, this process is not now ready for widespread use, but with more research effort, it may ultimately have very large application. The principal need is a strong oil price incentive in order for industry to proceed with the research and field testing needed to overcome the current technological problems. Polymer injection, a non-miscible process, has only small potential by itself, but will find wider application as part of the surfactant/micellar process. Alkaline flooding is a special version of the chemical process. It seems to be limited to a few types of crude oils and reservoirs and to be less efficient, but equally as fragile, as the surfactant/micellar process. Hopefully, additional research will overcome these limitations.

All these processes need special incentives to be implemented. But the most feasible incentive with the greatest potential would be the granting of special oil price to tertiary recovery projects.

If a decision were made today to proceed with a large scale tertiary project even foregoing a pilot, it would take at least five years before injection could begin and an additional two to five years before substantial oil response is attained. In the case of the CO₂ miscible project, an initial five to seven year period is needed to complete development of the CO₂ source, to build the CO₂ pipeline, and to prepare the oil field by infill drilling and to design and install facilities. In the case of the chemical process, a similar time will be needed to find an optimum surfactant/micellar/microemulsion material, to acquire an adequate supply, and to prepare the oil field, as mentioned above. Unlike secondary recovery processes which begin with an oil saturation of about 50 percent, tertiary processes begin with an oil saturation of 30-35 percent, necessitating more time to build an oil bank and move it to the producing wells. Thus, a significant lead time is required between the start of investment and the start of injection, and additional time will pass before the incremental barrels of tertiary oil are produced.

Implementation of these processes will require that the reservoirs be drilled on close spacing. In many cases, the current number of wells will be doubled. And in order to maintain control of these expensive injected fluids, most of flood patterns will be five-spots, that is, one injector for each producer. This requires

a large number of current producers be converted to injectors. We estimate that in order to achieve the higher rate contributions previously mentioned, the incremental new wells and well conversions will total about 160,000 over the 1980-1985 period. The total cost for this well work will be about 26 billion dollars. This includes neither the more routine well service work which must accompany the overall programs nor all the necessary pipeline and facilities construction activities. One study for the FEA [6] estimated that the development of 30.5 billion barrels of tertiary oil would require 150 billion dollars of capital, mostly for chemicals and other injected materials. Overall, a significant number of jobs will result from tertiary operations and not just in oil producing states. States which have manufacturing facilities for the chemicals and equipment will also benefit from enhanced recovery.

Other than the thermal prospects in California, the prime future prospects for tertiary recovery processes are the large fields in West Texas, New Mexico, Oklahoma, and the Rocky Mountain area. These target fields are ones which originally produced by solution gas drive, recovering 10-20 percent of their original oil-in-place, and which have since been unitized and waterflooded. Ultimate recoveries after waterflooding will be about 25-35 percent, leaving 65-75 percent of the discovered oil as the tertiary target.

Most of these fields have oil production rates which peaked several years ago and are now declining at rapid rates of 20-25 percent per year. Without the implementation of tertiary programs, these fields will reach their economic limits in 5 to 15 years and will have to be abandoned. The near to intermediate term abandonments are caused by the profit squeeze produced by rising operating costs (to lift increasingly large volumes of water) and decreasing weighted average oil prices caused by the current Upper Tier/Lower Tier/BPCL regulations. In most cases, the operating costs are so large that the economic limit is greater than 10 BOPD per producing well and the current stripper definitions are inadequate to provide assistance. Whenever these leases become uneconomic, the lease agreements become invalid and the mineral interests will revert to the mineral owners.

If we proceed to implement tertiary projects without more research and field testing, we incur large risks. But if we wait for several more years of research and field testing, many of our target fields may have to be abandoned before implementation can occur. Under current price control regulations, the potential economic rewards are inadequate to risk undertaking the projects now.

Industry needs an oil price policy for tertiary oil projects which provides either enough profit on the successful projects to offset the losses on the failures or some protection from large losses on the failures. The Congress has recognized this need and has called for tertiary incentives in the Energy Policy and Conservation Act of 1975 and the Energy Conservation and Production Act of 1976. But these statements are vague and as of this date have yet to be implemented by the regulators.

In early 1977, the FEA (now the ERA) finally published proposed rules which contained a basic proposal and several alternate incentive plans. Industry replied that the ERA's basic proposal—decontrolled price for the incremental barrels of enhanced recovery oil—was inadequate. In late 1977, the ERA issued its decision, setting forth a plan even more stringent than the basic proposal which industry had found inadequate. The ERA incentive would (1) apply only to the incremental barrels of enhanced recovery oil above the "projected maximum feasible production from existing recovery efforts"—a virtually indeterminate quantity, (2) apply only if the operator could prove that the project was not economic without the incentive, according to undefined ERA economic criteria, (3) be subject to removal if project production varied from the initially projected volumes because of a material error that the operator "knew or should have known," and (4) apply primarily to new projects only—penalizing previous risk takers. Presumably, it is the ERA objective that the incentive regulations must be so structured that producers will be denied large profits on their successful projects and yet must absorb the full losses from unsuccessful programs.

An incentive system based on granting decontrolled prices to the estimated incremental barrels is an inadequate concept not only because the incentives are too small and too late, but also because the incremental barrels are extremely difficult to determine. Exhibit 2 is a production graph of the Atlantic Richfield operated Willard Unit in Wasson Field, Yoakum County, Texas. This Unit is an example of a successful waterflood project and a prime target for the CO₂ miscible tertiary process. The graph shows four projections of secondary recovery performance made at different times. Currently the Unit is making about 16,300

BOPD (all lower tier oil), indicating that as of now one of the more pessimistic projections seems to be correct. The point is this. Had a tertiary recovery project been begun in mid-1975, or even early 1976, the projected secondary recovery rate would have been too high. And even if the tertiary project had been successful, few, if any, of the actual incremental barrels would have been decontrolled and the project would have been an economic failure. Thus the producer cannot be at all sure of actually getting the incentive, and this results in another risk on top of the process and reservoir risks.

Furthermore, current laws do not permit tertiary oil to be removed from the composite price. This means that even if the ERA issued a more favorable decision, two problems remain. As part of the composite price, whatever incentive is given tertiary oil will lower the price which the ERA can allow other domestic oil. And the history of regulated oil prices—frozen prices and price rollbacks—has shown that the industry must anticipate future adverse treatment from the regulators.

A new law is needed, a law that decontrols the price of all oil produced from a valid tertiary project and removes that oil from the composite price. The validity of the tertiary project could be established by the appropriate state agency or, in the case of federal lands, the USGS. The incentive should be given when the project begins, independent of economic calculations, and should be revoked only because of fraud or failure to implement the project.

By decontrolling the total oil production from the project at the time the project is initiated, the producers would obtain increased income from the non-tertiary oil to offset the high front-end investments which would otherwise not pay out for a number of years at best.

Such an incentive would be similar to the bonus allowables which were granted to improve recovery projects in Texas during the 1950s. These incentives served to encourage early enhanced recovery projects and to accelerate many secondary recovery programs at a time when even waterflooding was risky.

If the timing were not so crucial, if the risks were not so great, and if the petroleum industry could count on oil price controls expiring in 1981, a lesser incentive—such as decontrol of only the incremental tertiary oil—might be adequate. This is not the case.

S. 2623 will provide the needed stimulus, will be simple to administrate, and will be fair to the consumers. The lead time previously discussed is such that only a very small amount of presently controlled oil will be released between now and 1981, but the uncertainty of future oil price policy is sufficiently minimized to encourage the risk ventures and research acceleration needed to implement tertiary recovery.

An alternate proposal, S. 2999, is not adequate. This bill would provide certain loan guarantees and certain price guarantees, but is conceptually faulty. Its first incorrect premise is that incentives should be directed at the research or demonstration phase of tertiary recovery and not at the implementation phase. In fact, if the economics for full scale implementation are made sufficiently attractive, the producers will accelerate research and pilot testing even without R&D incentives, so as to get to implementation with its economic potential. If incentives are aimed at the R&D phase, they may encourage research and more research. But unless implementation appears to be economic, the research will not be effective. A second fault is that only first generation projects need incentives. In fact, both first generation and subsequent generation projects are risky. The first projects will have the most process risks but the least reservoir risks—as the best reservoirs will be implemented first. Later projects will benefit from less risky processes, but will be performed on poorer quality reservoirs. Finally, the price guarantees are based on the incremental barrel—an inadequate basis for the reasons previously discussed.

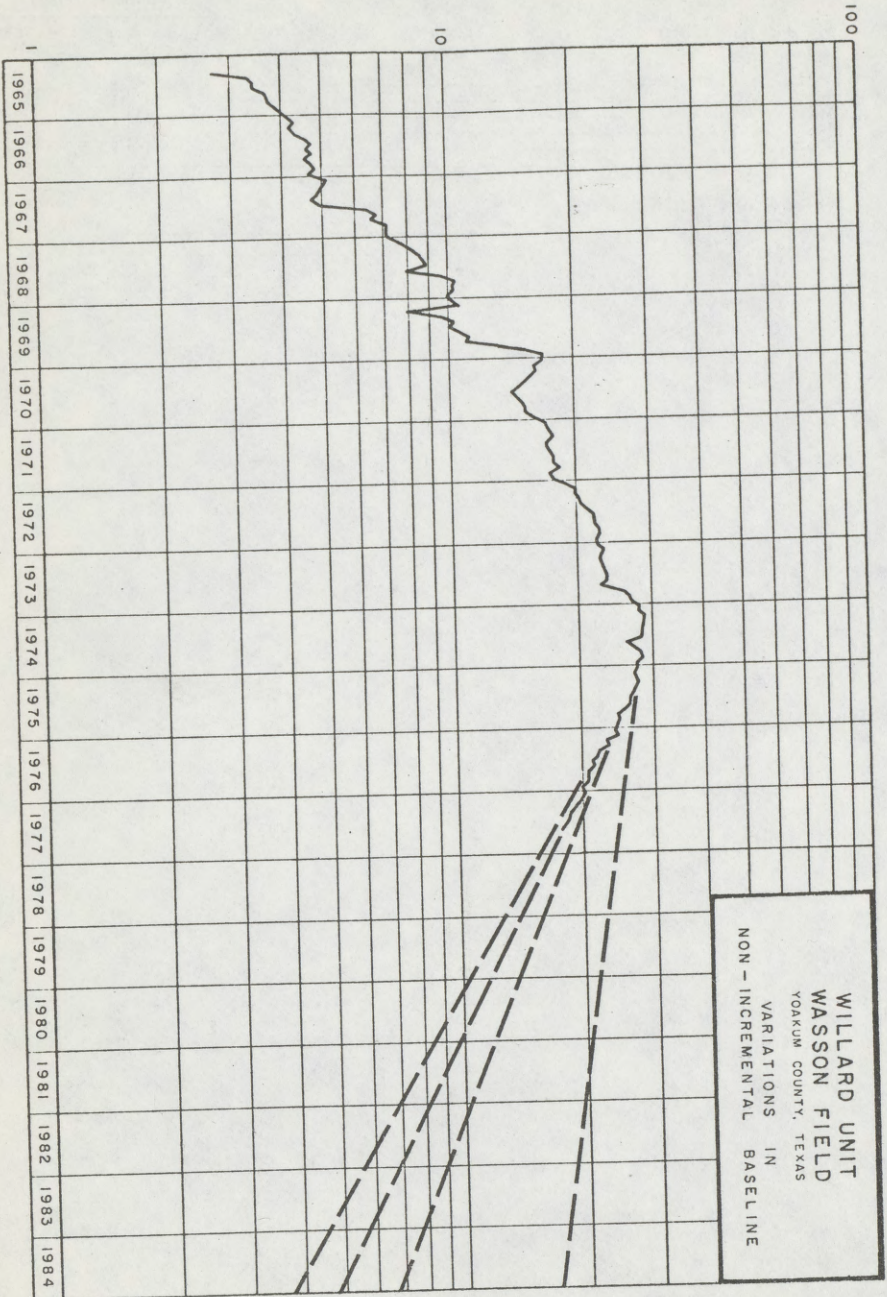
Atlantic Richfield supports S. 2623 and urges its adoption.

EXHIBIT NO. 1

NPC study (1976 dollars)	Potential enhanced oil recovery (billions of barrels)	
	Base case	Range
At \$ 5	2.2	1 to 3.
At \$10	7.2	3 to 13.
At \$15	13.2	6 to 27.
At \$20	20.5	9 to 32.
At \$25	24.0	12 to 33.

OTA Study (1976 dollars):	<i>Range</i>
At \$11.62	8 to 21.
At 13.75	11 to 29.
At 22	25 to 42.

MBOPD



REFERENCES

1. American Petroleum Institute, "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1977, June 1978".
2. National Petroleum Council's Committee on Enhanced Oil Recovery Techniques, "Enhanced Oil Recovery", December 1976.
3. Office of Technology Assessment, "Enhanced Recovery of Oil and Devonian Gas", June 1977.
4. Gulf Universities Research Consortium, Report No. 130, November 1973, and Report No. 148, February 1976
5. Mathematica, Inc., for the U.S. Environmental Protection Agency, "The Estimated Recovery Potential of Conventional Source Domestic Crude Oil", May 1975.
6. Lewin and Associates, Inc. for the Federal Energy Administration, "The Potential and Economics of Enhanced Oil Recovery", April 1976.

SUN PRODUCTION CO.,
Dallas Tex., September 12, 1978.

Re: Tertiary enhanced recovery incentives

GRENVILLE GARSIDE,
Staff Director, Energy and Natural Resources Committee,
Washington D.C.

DEAR MR. GARSIDE:

Sun Production Company has reviewed and found inadequate the Economic Regulatory Administration's regulations permitting to additional price incentives for tertiary enhanced recovery techniques (Federal Register 33679, August 1, 1978). Sun owns a 14.3 percent working interest in the SACROC Unit located in Scurry County, Texas. This unit operates a carbon dioxide augmented waterflood which is the largest enhanced recovery program in the world. Currently the cost of injected carbon dioxide is \$5.60 per barrel of additional oil recovered and other unit production costs are \$1.50 per barrel. These costs exceed the value of the additional oil recovered since the SACROC Unit oil is controlled at the lower tier price of \$5.80 per barrel.

Sun has actively encouraged the Department of Energy to issue regulations which would provide incentives to continue the SACROC enhanced recovery operation. Unfortunately the regulations issued for enhanced recovery operation have the following disincentives:

1. The producer's control of the enhanced recovery project would be severely impaired, since the certifying authority can, at any time, either retroactively or prospectively or both, revoke or modify the final certification and prescribe additional conditions or limitation.
2. The incremental production definition for existing project would result in an insufficient amount of production qualifying for market clearing prices.
3. The regulations pose the threat of large monetary liabilities arising from the certifying authority's power to retroactively modify or revoke the certification.
4. The regulations impose an overwhelming administrative burden in implementing and monitoring tertiary enhanced recovery projects.
5. The inclusion of production granted the incentive price in the statutory composite reduces the controlled price of other crude oil.

These disincentives have forced Sun Oil Company to recommend to the SACROC unit owners that the SACROC unit not file for tertiary incentives under these regulations.

Sun now believes that the tremendous enhanced recovery effort so desperately needed by this nation can only be obtained by Congressional action which will—

Free the total production from a bona fide enhanced recovery project area from price controls.

Provide for certification of such projects as qualified by a simple system utilizing state regulatory agencies.

Insure that the relief granted would not be rescinded except for fraud or failure to institute a project in good faith.

Remove enhanced crude from the composite price calculations.

We would be pleased to provide further information to you or your staff if you desire.

Very truly yours,

GLEN BURROUGHS.



