ENHANCED OIL RECOVERY IN CANADA

REPORT

The Special Committee of the Senate on the Northern Pipeline

The Honourable Earl A. Hastings, Chairman

March, 1981

REPORT OF THE SPECIAL COMMITTEE OF THE SENATE ON THE NORTHERN PIPELINE

ENHANCED OIL RECOVERY IN CANADA

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** Members of the Steering Committee

21 Members (Quorum 5)

March 18, 1981

REPORT OF THE SPECIAL COMMITTEE OF THE SENATE ON THE NORTHERN PIPELINE

ENHANCED OIL RECOVERY IN CANADA

The Special Committee of the Senate on the Northern Pipeline has the honour to present its Third Report as follows:

The Committee was authorized by the Senate, as recorded in the *Minutes of the Proceedings of the Senate* of July 10, 1980, "to examine and report upon the enhanced recovery technology of petroleum and natural gas and matters related thereto."

Your Committee, in accordance with the term of reference, has examined enhanced methods of recovering oil and offers this report on its potential for augmenting Canadian oil supplies.

The Committee in fulfilling its mandate, held seven public hearings in Ottawa. See Appendix A for Witnesses. In addition, a Subcommittee travelled to Alberta to view projects and heavy oil production facilities at Lloydminster and meet with industry officials in Calgary.

The Committee, in its meetings with government, industry and association officials, endeavoured to extract a full and frank disclosure of the issues and problems affecting enhanced oil recovery. The Committee appreciated the forthright way in which the evidence and information was presented, which in turn facilitated the task of making recommendations aimed at optimizing the exploitation of indigenous oil reserves.

The Committee expresses its appreciation to those who appeared at our meetings both in Ottawa and Alberta and to those who otherwise provided information. Their co-operation was most helpful.

We are particularly indebted to Ms. Sonya Dakers, Library of Parliament, for her valuable contribution to our research, study and report. Able technical assistance was provided by Dr. John Dawson of the Canadian Energy Research Institute. To Aline Pritchard, Clerk of the Committee and Daniel Amireault, Administrative Assistant, we express our sincere thanks.

SUMMARY AND RECOMMENDATIONS

Four billion barrels (636 million cubic metres) of recoverable oil in known reservoirs in the Western Canada sedimentary basin could become available if there were adequate economic incentives.

Innovative recovery technologies allow the extraction of oil previously inaccessible by conventional recovery methods.

These non-conventional methods, termed *enhanced oil recovery or tertiary recovery* (EOR) offer the promise of increasing and extending production in reservoirs where conventional output has been dropping and will continue to decline sharply under primary and secondary recovery methods.

The potential for enhanced recovery cannot be ignored since this oil would add more than 50% to Canada's remaining established conventional reserves of six billion barrels (1 billion cubic metres).

Time is of the essence. It is essential that these methods be put in place within the next few years if maximum potential is to be achieved.

Enhanced or tertiary recovery:

- extends conventional production and the useful life of existing facilities
- reduces Canada's petroleum shortfall until new supplies from the frontier and oil sands become available
- contributes technology to Canada, with direct and spin-off benefits

The Committee recognizes that a stated objective of the National Energy Program (NEP) of October 1980 was to encourage security of supply and energy independence, and to this end $30.00/barrel was proposed as a reference price for tertiary oil.

We commend the initiative as a recognition of the part enhanced recovery can play in meeting NEP goals. On the basis of evidence presented to the Committee, we doubt, however, that the reference price when combined with other features in the NEP will encourage a substantial increase in EOR activity.

Enhanced oil recovery is a high-risk venture which requires a favourable business climate and adequate producer revenues to realize its potential. The present federal-provincial deadlock over resources creates uncertainty and impedes EOR development.

Evidence placed before the Committee has led members to conclude that the risks associated with enhanced recovery are comparable with those in oil sands development, particularly in the early years when costs are high and the success of recovery schemes is in question.

The weight of evidence strongly suggests that further action is warranted at this time to encourage EOR development. The Committee believes that a re-examination of the costs and economic factors will support this view. Your Committee therefore recommends:

- *The reference price for incremental oil produced from approved EOR projects be the same as the oil sands reference price having regard to quality differential.*

  or
- *Incremental oil produced from approved EOR projects be exempt from the proposed Petroleum and Gas Revenue Tax until capital costs are recovered.*

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  or

- *Incremental oil produced from approved EOR projects be exempt from the proposed Petroleum and Gas Revenue Tax until capital costs are recovered.*

- *The tertiary supplement, used to achieve the EOR reference price, be paid through a method which allows producers an earlier return on investment. This presumably would be the fixed proportion method.*

Injection materials represent a substantial portion of operating cost in enhanced oil recovery. Your Committee endorses the removal of the excise tax on natural gas and natural gas liquids injected into reservoirs in pressure maintenance and miscible flood schemes, and further recommends:

- *That natural gas and natural gas liquids used in approved enhanced recovery projects be exempt from the proposed Petroleum and Gas Revenue Tax.*

With respect to very heavy oil below 15° to 16° API where primary and secondary production is low:

- *Consideration should be given to applying the EOR reference price to the entire production.*

Your Committee also notes that marketing problems will continue until adequate upgrading facilities are established in Canada. In the interim, in order to assure continued EOR development, we suggest that adequate export markets be maintained. This would be encouraged by the issue of export permits on a quarterly basis.

In conclusion, the Committee believes that if the economic constraints are alleviated, we have the technological and human resources available in Canada to proceed expeditiously with enhanced oil recovery.

INTRODUCTION

On average, Canadian oil reservoirs containing light and medium oil yield perhaps one-third of the oil-in-place when produced using natural reservoir pressure (primary recovery) or by artificial injection of water or gas (secondary recovery). For heavy oil reservoirs the proportion of the oil recovered by these conventional methods is less than 10 per cent. Currently available technologies, however, now provide the means to recover a further 10 to 15 per cent of the oil remaining in many of the reservoirs. The recovery methods that are utilized to extract this oil are termed *enhanced oil recovery or tertiary recovery* (*EOR*). See Appendix B on Definitions and Appendix C for EOR Processes.

EOR could extend the recovery from Canada's established reserves of conventional oil by an estimated 4 billion barrels (636 million cubic metres) and thus make a significant contribution to this country meeting its own requirements for oil. The extent to which this potential is exploited, however, will depend upon the economic climate over the next few years, the critical period for capitalizing on this resource.

THE POTENTIAL OF EOR IN CANADA

1. Projections

In Canada, of the original oil-in-place discovered to date, excluding frontier regions and oil sands, a total of 9 billion barrels (1.4 billion cubic metres) has been produced and another 6 billion (1.0 billion cubic metres) is considered recoverable by primary and secondary recovery methods. Depending on the reservoir, about one-third to two-thirds of the light and medium oil and 90 per cent of the heavy oil originally in the reservoirs will not be recoverable with these conventional methods. It is to this large residual that enhanced oil recovery methods are directed. At the present time, the development of EOR in this country is in its infancy. See Appendix D for History and Status of EOR.

Evidence before the National Energy Board (NEB), which is currently revising its projections of future Canadian energy demand and supply, suggests that the potential for EOR has increased since its 1978 review. This optimism has been attributed to improvements in recovery technology and the prospects of higher oil prices, which have increased the number of oil reservoirs suitable for enhanced recovery. In 1978 the NEB, based on its analysis and on submissions by industry, projected a recovery of 2.7 billion barrels (434 million cubic metres) with some 60 or 70 per cent coming from deposits containing heavy crudes. In the preliminary figures available to the Board in its present study, estimates fall into a range depending on how the reserves base is calculated by individual companies and on assumptions concerning the timing of bringing economic projects into production. This time frame will depend on the financial outlook of individual EOR projects and on the availability of equipment, materials and manpower. The rate of technological advancement will also have an impact. Seven years is about the average time required to bring on-stream a large-scale project.

The NEB preliminary projections give a range of estimated reserves additions for each major EOR technique. As many pools are suitable for the application of more than one technique and because the economics of various techniques can change significantly with time, potential EOR reserves can readily shift from one EOR category to another. However, such changes should not affect the total EOR potential. Figures for total EOR potential are thus more meaningful than numbers on the potential of individual EOR techniques.

When enumerating total EOR potential it can be seen from Table 1 that the 1978 expected case for light crude oil of 1.0 billion barrels (156 million cubic metres) falls in the lower part of the range of the recent Board studies. The upper limit of 2.6 billion barrels (410 million cubic metres) is significantly higher than the 1978 high case of 1.6 billion barrels (259 million cubic metres), not shown here. The escalation for heavy oil is less dramatic. The 1978 expected case of 1.7 billion barrels (278 million cubic metres) falls only slightly above the middle of the new EOR potential of from 0.9 to 2.3 billion barrels (137 to 365 million cubic metres).

Other estimates presented to the Committee, some of which are also reflected in the NEB estimates, confirm the substantial potential that exists for enhanced oil recovery. They also confirm the sensitivity in the amount of oil that may actually be realized from enhanced oil recovery to the economic returns that oil producers may expect to realize. For example, IPAC, which speaks for independent Canadian producers, presented evidence from an analysis of 169 pools accounting for 60 per cent of Western Canada's conventional oil in place. It indicated a tripling of projected EOR production as the producers' total share of the wellhead price increased from \$12 to \$24, in 1980 dollars. An earlier study by J.P. Prince for the Canadian Energy Research Institute, in which all Alberta reservoirs were analyzed, obtained a similar response as the wellhead price, in 1978 dollars, increased from \$15 to \$25. At the high end of these ranges in each case, the estimate of the total amount that would be recovered through enhanced recovery methods in Canada was in the order of 4 billion barrels (636 million cubic metres).

The NEB preliminary estimates were made before details of the implementation of the incentives in the National Energy Program (NEP) for enhanced oil recovery had been clarified. The program proposed a tertiary reference price of \$30.00/barrel in 1981. While

Table 1

EOR POTENTIAL: CURRENT NEB STAFF STUDY

(millions of barrels)

	Range of Expected Potential (1978 Estimates are shown in brackets)		
	LIGHT	HEAVY	TOTAL
Chemical Flooding	0-76 (308)	0-13 (25)	0-88 (334)
Infill Drilling	25-50* (132)	**	25-50 (132)
Miscible Flooding	478-2001 (371)	0-164 (107)	478-2165 (478)
Thermal Techniques	0-19 (31)	365-1573 (1447)	365-1592 (1479)
Waterflooding	390-434 (138)	497-547 (170)	887-982 (308)
TOTAL	894-2580 (982)	862-2297 (1749)	1756-4877 (2731)

* Infill Drilling included in tertiary potential estimate where applicable.
** Included in waterflood estimate.

Source: National Energy Board, Brief Prepared for the Special Committee of the Senate on the Northern Pipeline respecting Enhanced Oil Recovery in Canada, December 1980, p. 3-14.

certain companies believe that the new reference price is a move in the right direction, others assert that the Canadianization aspects and the Petroleum and Gas Revenue Tax (PGRT) of 8 per cent detract from the favourable price provisions. As a consequence, many companies have reduced their estimates of the amount of oil that will be recovered through enhanced recovery. IPAC has stated that only 29 per cent of the technological EOR potential will be reached under the existing regulatory regime.

2. Constraints on EOR Development

(1) Technical Risks

While there is a large resource base to which EOR methods can be applied, enhanced recovery projects are difficult and costly, and the results do not become apparent until after most of the money has been invested. As a first step in examining potential EOR development, reservoirs are screened to determine which projects might be technically feasible and what EOR processes might be appropriate. Specific candidates are then evaluated as to the amount of oil that will be left after primary and secondary recovery, and the particular characteristics of the reservoir that will influence the amount of tertiary oil recovered. Because no two petroleum reservoirs are identical and the engineering data base is not complete until a pool is abandoned, there are many uncertainties in proceeding with reservoir development.

Technical risk arises from this complexity and uncertainty. Even though pool performance and recovery can now be estimated by computer modelling, the application of computer simulation and the process of scaling-up laboratory tests still result in large errors because of inadequate knowledge of the reservoir. Consequently, successful implementation of EOR schemes is by no means assured.

Pool performance must be promising to warrant the very large investment in wells, equipment and injection fluids for an EOR program. A large-scale tertiary recovery project may well entail two years for pilot design, testing and analysis, and up to five years from start to fluid injection, with production beginning in the seventh year.

The heavy "front-end" investment must be made before incremental oil begins to flow. This long lead time before knowledge begins to accumulate concerning reservoir response holds additional risks related to loss of injection fluids, well damage or adverse chemical reactions associated with certain EOR methods.

Companies will not invest in such technically risky and uncertain ventures unless the economics of the situation promise an adequate return on investment. For heavy oil, the technical risks have a special impact because the economics of exploration and primary and secondary development have always been more marginal than for light oil. The special concerns in enhanced recovery of heavy oil include lack of thickness in most of the reservoirs, as well as the technical problems associated with handling viscous crude.

(2) Economic Constraints

As stated above, investment in EOR ventures depends on the investor believing that he will recover his investment in enhanced recovery within a reasonable number of years. The price of the oil is only one of the factors influencing the investment decision. It is the netback -- defined as the flow of revenue to the producer after the deduction of all government taxes and royalties, both provincial and federal, as well as operating expenses -- which governs the inclination of the investor to proceed. In Canada, the low netbacks to the industry have up to now precluded all but the most attractive enhanced recovery projects.

This is why royalty and tax regimes, in addition to prospective prices, can play such an important part in influencing decisions to undertake what the oil industry considers to be high-risk investments. In EOR, because a return on investment is realized only after several years, a stable royalty, tax and pricing regime is essential. If the rules of the game are changed, a project that was economical when begun could turn uneconomical before the incremental oil begins to flow. Thus changes in revenue sharing and in government regulations can affect the business climate to such an extent that companies are not willing to take the risks involved in proceeding with EOR.

Not only must the investor face very high front-end costs but also the considerable uncertainty as to annual operating and additional capital costs during the life of the project. When coupled with the risks involved in accurately matching the process to suit the reservoir and in estimating the amount of oil that will be recovered, financing may also prove to be a considerable obstacle to EOR development, especially for the small independent operator.

Even with viable economics in an EOR project, producers must also have assured markets. One of the major problems in developing heavy oil is availability of markets. For the next few years continued access to export markets is essential. For the longer term, a combination of upgrading facilities in Western Canada and changes in refining facilities in Eastern Canada are required to make effective use of heavy oil in Canada.

(3) Other Obstacles to Accelerated EOR Development

There is general agreement that in the near term, miscible flooding offers the greatest potential for EOR in Canada in light oil reservoirs, as shown in Table 1. Our relatively more plentiful supply of natural gas and natural gas liquids would lend itself to a natural emphasis on hydrocarbon miscible processes. Nevertheless, there remains the possibility of using CO_2 as an injection fluid. In the latter case, CO_2 supply could be a constraint in the near term. This is because Western Canada does not have as ready access to CO_2 as does the U.S., where some major natural sources occur in relatively close proximity to oil reservoirs that are amenable to CO_2 flooding. Even if Canada does follow suit in the use of CO_2 as an injection fluid, its availability is not expected to present a constraint once heavy oil upgrading plants, oil sands plants and new fertilizer plants come on-stream since one of their by-products happens to be CO_2. The pipelining of CO_2 from the source to the oil field represents, however, a major investment.

The need for continued research and development could be a determining factor in the rate of implementation of large-scale commercial projects. While there is a considerable amount of industry and government-sponsored R&D going on in Canada relating to EOR technology, there is little evidence of long-range basic research being conducted through universities and research agencies at a level commensurate with Canada's EOR opportunities. For the research to be relevant and timely, it must be carried out to take account of Canadian reservoir conditions. Thus while U.S. technology is transferable, it may not always be appropriate. Some of the methods applicable, for instance, to the thick reservoirs typical of parts of California may not be transferable without adaptation to the thin reservoirs of certain fields in Saskatchewan.

The most critical constraining influence, however, is likely to be skilled manpower, especially in view of concurrent energy projects. EOR projects require significantly more engineering expertise than conventional oil recovery methods. Reservoir engineers and technicians require special training and experience in tertiary methods. Research chemists and chemical engineers with training in petroleum upgrading are also required. Full-scale initiation of enhanced recovery projects will increase the demand for people trained in these areas though the increase is difficult to quantify.

A significant amount of the required training is likely to be provided in-house by operators themselves. However, the level of activity envisaged by the Committee implies a need for a more substantial training effort. The lag in introducing formal training at the university level is likely to cause some delays in implementing projects. At the present time, only one university in Canada offers a degree in petroleum engineering. Universities and technical schools need to be alerted to this problem to prevent costly delays caused by skilled manpower shortages.

FINDINGS

1. The Business Climate

A foregoing section has outlined the potential offered by accelerated EOR development if the hindrances posed by technical and economic risks can be overcome. The Committee is convinced that certain conditions must exist before companies will turn increased attention to enhanced oil recovery.

A low price for oil works against EOR development and, although domestic crude oil prices have increased substantially in recent years, so have the costs of goods and services in the petroleum sector. The industry maintains that potential profitability remains poor when account is taken of the risks involved and the large investments required. The industry considers EOR development to be more of a risk in some ways than oil sands extraction or frontier development. Conditions in each reservoir vary so greatly that years of work may be required to design the right recovery technique. In such circumstances, the willingness to proceed depends in the final analysis on the anticipated netback. Producers have indicated that the average netback that existed before the National Energy Program would have to double for a significant fraction of the EOR potential to be realized.

Current tertiary production of light and heavy oils at about 14 thousand barrels/day (2 thousand cubic metres/day) contrasts with the estimate that such output could reach 283 thousand barrels/day (45 thousand cubic metres/day) in 1990 under optimum conditions. This represents a rapid implementation of EOR projects; however, the output by 1990 might only be one-quarter of this potential. The level of activity is clearly related to the extent to which the business climate fosters such activity. From the interest in enhanced recovery demonstrated by companies in their submissions to this Committee and to the National Energy Board, the Committee is led to conclude that the time is opportune for accelerated EOR activity.

Spurred on by the need for oil self-sufficiency, the attractiveness of exploiting a known resource, and the expectation of higher returns, companies are considering whether to push ahead with such schemes today. This new willingness is seen in the expert teams assembled to plan and develop projects such as Judy Creek and in the number of pilot projects ready to commence. Many of the reservoirs, however, are operated by multinationals who stand to lose under the NEP unless they can increase their Canadian content and thus benefit to the maximum from incentive payments. In the present uncertainty, momentum may be lost.

2. The Role of Incentives

Even though EOR promises to increase Canada's indigenous oil supplies, it is evident that enhanced recovery will only be attempted if the economic climate is favourable. It is the Committee's view that government policy sets the tone for development. Consequently, pricing policy must recognize the risks involved and must help to create the rewards necessary to encourage these risky ventures. There is no doubt the National Energy Program offers certain incentives -- as outlined along with fiscal measures provided by the provinces in

Appendix E -- thereby recognizing the part EOR can play in Canada's energy goals.

Before the NEP, as has been noted, there was little sustained EOR development except for the most economically attractive projects; at that time, planning had started on a number of additional projects. Economic projections for these schemes were based on a variety of expectations as to how rapidly wellhead prices would rise from the then current $16.75 per barrel. The $30.00 tertiary oil reference price (with projected escalation at the rate of increase of the Consumer Price Index) by itself would have encouraged a significant boost in EOR activity. Analysis of prospective costs and netbacks presented to the Committee, however, indicate that when coupled with other measures in the NEP -- such as the Petroleum and Gas Revenue Tax, changes in the depletion allowance, and the Canadianization program -- it is questionable whether the $30.00 tertiary oil reference price will be sufficient to encourage a substantial increase in EOR in view of the risks in extracting oil by these relatively new methods. To match the risks that accompany enhanced oil recovery, the Committee believes that tertiary oil must be treated in the same manner as that from the oil sands and be accorded the same price. Another alternative would be to remove the PGRT on incremental oil from approved EOR projects until capital costs have been recovered. In addition, the producing provinces could further adjust their royalty rates and provide other incentives to stimulate tertiary recovery.

It is realized that a tertiary supplement is an appropriate vehicle to achieve the tertiary oil reference price. The Committee also considers that the method of application of the tertiary reference price is of utmost importance since it should allow producers an earlier return on investment for projects with long lead times, high initial capital expenditures and technical risk. If the supplement is only paid as the incremental barrels are produced -- which may be a number of years after the project is initiated -- companies will not be able to benefit from the favourable price at the time they most need it. In contrast, the fixed proportion method assigns a factor to the oil produced from a tertiary project based on the ratio of the tertiary recoverable reserves to the total recoverable reserves. The factor is fixed under usual provincial practice for the life of the project but could be reviewed on the basis of production performance. This method thus provides an earlier return on investments. For heavy oil below 15° to 16° API, where there is little primary and secondary production, it would benefit the economics and administration of EOR projects for the entire production to qualify for the tertiary oil reference price.

One of the highest costs in many EOR projects is expenditure on hydrocarbon injection materials. It is the Committee's view that the PGRT should not be applicable to natural gas or natural gas liquids used as injection materials in EOR projects.

BENEFITS TO CANADA

Enhanced recovery offers a means of reducing Canada's dependence on insecure offshore supplies of increasingly expensive oil. If action is not taken soon, some of these incremental oil supplies may be lost forever as the costs of extraction escalate; enhanced recovery cannot be initiated too late in a reservoir's producing life. Furthermore, EOR may be less expensive at the present time than some of the energy alternatives being considered in Canada. It certainly can be brought into the market more quickly than a number of these alternatives.

Since the energy crisis of late 1973 and Canada's subsequent emphasis on self-sufficiency in energy resources, a lot of attention has been directed to new sources of oil and gas, not only from the oil sands but also from the Arctic and offshore. With escalating development and production costs, and difficulties in transportation, however, these sources are less accessible and probably more costly than relying on augmented conventional supplies.

The technical expertise arising from research activities and special training can be transferred in substantial measure from EOR development to, for example, oil sands development. The earlier this specialized knowledge is made available, the better Canada's energy future will be.

Primary and secondary recovery efficiencies are not good enough in the oil business today. Detailed reservoir studies often reveal the opportunity to boost recovery efficiency through enhanced production schemes. These improved recovery techniques can also be applied in developing production strategies for newly-discovered pools to increase the recovery rate at an earlier stage. Similarly, these techniques should improve future recoverability in frontier applications and certain types of EOR technology have relevance for oil sands development. As the understanding of these complex recovery processes increases and more detailed engineering information on reservoirs is collected, a range of applications not anticipated originally may become apparent.

In summary, enhanced oil recovery can augment Canada's energy supplies until such time as alternative supplies such as oil sands or frontier petroleum resources are available. Its accessibility and known quantity should not be ignored and it is essential that measures be taken to achieve its ultimate potential.

APPENDIX A

WITNESSES WHO APPEARED BEFORE COMMITTEE & SUBCOMMITTEE

Date	Organizations & Witnesses
November 4, 1980	Getty Oil Company A. Trimble, Manager, Engineering (Natural Resources)
	Canadian Reserve Oil & Gas Ltd. J.R. Dundas, President
November 12, 1980	Petroleum Recovery Institute Dr. F.G. McCaffery, Manager, Research
November 26, 1980	Canadian Energy Research Institute Dr. J.A. Dawson, Executive Director Dr. J.P. Prince, Staff Economist
December 2, 1980	Canadian Petroleum Association T.E. Randall, Chairman, EOR Committee J.D. Griffith, Vice Chairman, EOR Committee
December 10, 1980	Independent Petroleum Association of Canada J.E. Horler, Manager, Crude Oil Affairs M.S. Abougoush, Consulting Engineer
December 16, 1980	National Energy Board J.R. Jenkins, Board Member K.W. Vollman, Director, Energy Resources Branch G.C. Hos, Assistant Director, Oil Supply W.A. Hiles, Assistant Director, Geology & Reserves A.M.H. Gutek, Chief, Supply Analysis & Statistics M.C. Walker, Head, Financial Models
January 20, 1981	Department of Energy, Mines & Resources G. Tough, Director General, Energy Strategy Dr. J.P. Hea, Director General, Petroleum Resources M. Feldman, Policy Analyst, Petroleum Resources T.A. Hamp, Petroleum Resource Scientist, Petroleum Resources

January 27, 1981 Husky Oil Ltd. (Lloydminster)
R.R. Bagby, Senior Vice President
H.J. Berry, Vice President, Production
B. McCutcheon, Manager, Corporate & Community Affairs
K. Hill, Manager, Lloydminster Production
T. Vonde, Manager, Thermal Operations
W. Willis, Manager, Pipeline Division
V. Juba, Manager, Lloydminster Refinery

January 28, 1981 Husky Oil Ltd. (Calgary)
R.R. Bagby, Senior Vice President
R.H. Roda, Group Vice President
A.R. Price, Vice President, Refining, Marketing & Upgrading
H.J. Berry, Vice President, Production
M. Swan, Manager, Engineering
R.H. Waraksa, Staff Engineer

Esso Resources Ltd. (Calgary)
J.H. Hamlin, Director & Senior Vice President
P. Stauft, Vice President
G.L. Haight, Vice President & General Manager, Production
J.D. McFarland, Manager, Reservoir Engineering
P.F. Johnson, Manager, Judy Creek Project

Mobil Oil of Canada Ltd. (Calgary)
A.E. Barroll, Vice President
D.J. Bester, Engineering Manager
S.K. Bhatia, Reservoir Engineer
H.E. Klaver, Supervisor, Planning

January 29, 1981 Shell Canada Resources Ltd. (Calgary)
R.A. MacDonell, Vice President & General Manager, Production
K.J. Hindmarch, Manager, Production Division
B.D. Weatherill, Senior Reservoir Engineer, EOR
C.P. Lihou, Senior Production Engineer, EOR
R.G. Gorrill, Vice President & General Manager, Synthetic Oils
P. Kitzan, PRISP Engineering, Manager
J.D. MacDonald, Joint Venture & Heavy Oils
S.G. McDonald, Senior Economist

Aquitaine Company of Canada Ltd.
B.F. Isautier, President, Exploration
H.R. Martial, Vice President, Production
R. Chenery, Manager, New Resources Development

Murphy Oil Company Ltd.
L.E. Pasychny, Vice President, Supply & Transportation
R.R. McLean, Production Manager

January 30, 1981 — Gulf Canada Resources Inc.
E.W. Frankovich, Manager, Production Development
K. Lund, Manager, Enhanced Recovery
H.T. Guyn, Manager, Heavy Oil Division
T. Randall, Coordinator, Technology in EOR Group
A. Bhasin, Director, Public Affairs
D. Ziemelis, Coordinator of Project Development in EOR Group
M. Rehman, Coordinator of Willmar Project in EOR Group
W. Rennie, Economic Engineer

APPENDIX B

DEFINITIONS

Oil reservoirs are volumes of porous rock holding water, oil and gas under pressure. Drilling a well into an oil reservoir releases the pressure so that initially the oil comes to the surface by means of this natural pressure inherent in the oil reservoir. Sometimes pumps are used to supplement the natural reservoir pressure in lifting the oil to the surface. The average recovery factor, that is, the percentage of the original oil-in-place that is produced at this primary stage, is roughly 22 per cent.

Secondary recovery entails maintaining reservoir pressure by artificial means, such as the injection of water or gas into the reservoir. This acts to displace the oil towards the producing wells and can add about 50 per cent to recoverable oil reserves, bringing the average recovery factor up to some 33 per cent. This average recovery factor pertains to light and medium oil reservoirs. It is much lower in heavy oil reservoirs.

Tertiary recovery is directed at the two-thirds of the initial oil still in place, termed residual oil. This recovery method improves the overall displacement process, first of all, by contacting more of the reservoir and, secondly, by improving the efficiency of the displacement process by which the oil is captured out of the pores of the rock. Tertiary methods work by improving the sweep efficiency and by altering the properties of the oil itself, thereby increasing its recoverability.

The term "enhanced recovery" is used to differentiate the process from a conventional one whether this process is used at the primary, secondary or tertiary phase so that the definition accepted by the industry is "the additional recovery of oil from a petroleum reservoir over that which can be economically recovered by conventional primary and secondary methods."

APPENDIX C

ENHANCED OIL RECOVERY (EOR) PROCESSES

(1) Thermal Processes

Steam injection is the most widely employed EOR process and is mainly applied in heavy oil recovery where it is used in California and Venezuela. Its use on a major scale is also planned in Canada's Cold Lake and Peace River oil sands deposits, and in approximately 10 per cent of the heavy oil reservoirs of the Lloydminster region. The conventional heavy oil reserves of Alberta and Saskatchewan have a limited potential for steam processes as most of the oil occurs in thin deposits. Heat loss to the over and underlying formations makes steam injection impractical in thin oil deposits.

Steam injection reduces the viscosity of the oil through heating and facilitates production either by the method of steam stimulation or by steam drive. In steam stimulation, the same well is used for both injection and production, on a cyclic basis. Steam is injected for a period of time followed by a "soaking period" after which the less viscous oil is produced. This process is called cyclic steam injection or "huff and puff". Where a pattern of wells is used in which steam is injected in one or more wells, displacing the heated oil to adjacent producing wells, the process is called steam drive or steam flooding.

Fireflooding or <u>in situ</u> combustion is a process whereby the oil in the reservoir is ignited and the fire is sustained by air injection. The unburnt portion of the oil becomes less viscous, is partially vapourized, and is driven towards a production well by a combination of steam, hot water and gas drive. In a modified method, air and water are injected alternately or concurrently, improving the efficiency of the operation. It is therefore the preferred method if the formation at the injection wells is sufficiently permeable to permit the combined injection of water and air.

The in situ combustion process has also been extensively field tested; however, it is technically complex and difficult both to predict and to control. Of the 26 active field tests operating in the U.S. in 1976, eight were termed successful, nine unsuccessful, and the remainder were under evaluation. Fireflooding is frequently assumed to be the only method applicable to Alberta and Saskatchewan conventional heavy oil reserves as it is the only known process that will recover heavy oil in thin deposits. About 90 per cent of Lloydminster heavy oil is in deposits less than seven metres thick.

(2) Miscible Processes

Miscible processes are those in which an injected fluid dissolves in the oil it contacts, forming a single oil-like liquid that can flow through the reservoir more easily than the original crude oil. The miscible displacement process overcomes the capillary forces that otherwise retain oil in pores of the rock. A variety of fluids can be injected depending upon reservoir characteristics, the nature of the crude oil-in-place and the availability of fluids. Carbon dioxide and liquid petroleum gases (LPGs) such as ethane, propane and butane are the most widely used. In this process a "slug" of the injection fluid, which varies from 5 to 20 per cent of the reservoir pore volume, is often displaced through the reservoir by gas (natural gas or nitrogen) or water. The injected fluids are partially recoverable from the produced crude oil and may be reinjected to decrease the injection fluid requirements of the project.

A number of hydrocarbon miscible flood projects are operating in Alberta and a CO_2 miscible flood has been proposed by Imperial Oil for the Judy Creek A pool. It has been estimated that CO_2 miscible flooding will account for 40 per cent of future tertiary produced oil in the U.S.

Limiting factors are the availability and cost of injection fluids. In Alberta and Saskatchewan, however, a large supply of natural gas liquids is still available which, coupled with limited availabililty of pure and cheap CO_2, may encourage hydrocarbon miscible flooding in future projects. Larger volumes of CO_2 will be available from new synthetic oil plants and other sources in the late 1980s.

(3) Chemical Processes

Three main chemical flooding methods are currently under investigation: surfactant/polymer, polymer and alkaline flooding. These processes are the least proven of the three general classes of EOR methods. They rely on an ability to control the propagation of one or more chemical slugs through the reservoir without their becoming excessively diluted and ineffective. The high-cost chemical slug must therefore be precisely designed to be compatible with the particular reservoir oil-water-rock system and formulating the right chemical flood is a very complex process.

A number of major pilot tests of surfactant/polymer flooding are underway in the U.S. to assess their technical and economic feasibility. Seven of these tests are joint industry-government efforts, in which a total of $122 million is being spent. Surfactant/polymer flooding (also known as micro-emulsion and micellar flooding) is a process in which detergent-like materials are injected as a slug of fluid to lower the interfacial tension between the reservoir oil and water. The process emulsifies or otherwise dissolves the oil within the formation. It is a one-pass process where irregular movement of the polymer/water drive can greatly reduce recovery. Polymers have also been used simply to augment waterflooding, a method employed commercially on a limited basis in both the United States and Canada.

Only a few field tests have been reported on caustic or alkaline flooding. There are currently two large pilot tests of alkaline flooding for tertiary oil being conducted in California under joint sponsorship of the field operator and the U.S. Department of Energy. Caustic or alkaline flooding relies on the presence of certain constituents in the crude oil which react with injected caustic solutions to produce detergent-like materials and improve oil mobility. It has an advantage over surfactant floods in that the chemicals required are not expensive. It is a high risk process, however, which is only applicable where the crude oil has suitable chemical properties.

APPENDIX D

HISTORY AND STATUS OF EOR IN CANADA

EOR in Canada dates to a time when crude oil productive capacity far surpassed domestic and export demand. Oversupply led to a system of allocating producing volumes according to identified reserves, which encouraged supplementing reserves by means of secondary and tertiary recovery schemes.

Some of the early schemes were miscible flood schemes. One was commenced in 1963 by Imperial in the Golden Spike reef and another by Mobil and Amoco in the same year in the Pembina Cardium sandstones. The Pembina horizontal flood was prematurely abandoned in 1969 because of early breakthrough of the miscible slug into the producing wells. However, the success of Imperial Oil's LPG vertical miscible displacement, which continued at Golden Spike reef until 1978, encouraged the same method in the first Rainbow reef in 1968, and there are presently 13 commercial-scale Rainbow EOR projects operating.

A large LPG miscible flood was commenced in 1970 in the Wizard Lake D-3 reef and injection in this pool continues. Wizard Lake is a commercial-scale operation. An even larger miscible flood is being conducted in the Swan Hills South pool where injection started in 1973. The latter flood is of the horizontal type which proved less successful in Pembina. However, to prevent premature breakthrough of injected hydrocarbons, LPG injection is alternated with injection of water and this appears to be successful. It is one of the larger commercial-scale projects presently operating in Canada.

More recently, in 1977, a large-scale miscible flood using ethane was implemented in the Willesden Green Cardium A pool. Initial production performance indicates that this project has responded favourably to the injection of ethane. Subsequent injection of nitrogen will help recover most of the ethane.

The project of Esso Resources to implement a CO_2 flood in the Judy Creek field, which has been approved by the Alberta Energy Resources Conservation Board (AERCB), is presently being re-evaluated by its sponsor.

While the main economic targets for EOR have been light and medium oil pools suited to miscible flooding, some progress has been made with respect to heavy oil. Thermal techniques are the most successful in heavy oil pools. Mobil Oil has effectively improved heavy oil recovery through in situ combustion with air injection. The first project was started in the Battrum field in Saskatchewan in 1965 and injection is continuing. The air supplies oxygen for burning part of the oil in place. Since 1978, injecting water in conjunction with the combustion process has improved production performance. The experience gained in Mobil's commercial-scale fireflood projects at Battrum in Saskatchewan will no doubt benefit similar projects currently being considered for heavy oil pools in the Lloydminster area. The method is suitable for heavy crudes found in eastern Alberta and western Saskatchewan, and indeed in situ combustion pilots in the Lloydminster area have already yielded a range of results.

In addition to these commercial-scale schemes, there are a number of field pilots operating in Canada. Most of the emphasis has been on heavy oil pilot tests where steam processes have been tested under a variety of conditions. Mechanical problems have prevented sustained rates of high volume production for the relatively thin oil deposits in Canada. The success of steam injection techniques in California has led to technological advances in the design of steam generators. A downhole steam generator currently under development has the potential to open up deeper reservoirs for steam flooding by reducing heat losses.

This historical outline has concentrated on a description of commercial-scale EOR developments. There are also a number of experimental-scale projects in operation in Alberta and Saskatchewan evaluating various tertiary recovery processes. Table 1 indicates the numbers and types of EOR projects in Canada.

Table 1

TERTIARY CRUDE OIL PROJECTS IN CANADA

Commercial Scale		Experimental Scale	
Light and Medium Oil	Heavy Oil	Light Oil	Heavy Oil
Alberta - 17 Hydrocarbon Miscible	Sask. - 3 Thermal	Sask. - 1 Hydrocarbon Miscible	Alberta - 8 Thermal
			Sask. - 7 Thermal 1 Chemical

Source: National Energy Board, Brief Prepared for the Special Committee of the Senate on the Northern Pipeline respecting Enhanced Oil Recovery in Canada, December 1980, Appendix A.

APPENDIX E

FEDERAL AND PROVINCIAL FISCAL MEASURES AFFECTING EOR*

(1) Federal Measures

The National Energy Program was presented to Parliament on October 28, 1980. It specifies a wellhead oil price schedule which is dependent on the source of the oil as shown in Table 1. A special incentive price is provided for oil produced using approved tertiary enhanced recovery methods. A "tertiary supplement" which is additional to the conventional oil wellhead price will be paid by the Government of Canada to qualifying producers. For example, as of January 1, 1981 the supplement will be approximately $14.00/barrel, applied equally to all qualities of crude oil. For a company producing a representative 15° API gravity crude oil through approved tertiary methods, the total wellhead price (the tertiary reference price) as of January 1, 1981 is approximately $30.00/barrel. The tertiary reference price will be adjusted annually by the Consumer Price Index.

Implementation of this tertiary recovery incentive depends upon agreement with the oil-producing provinces. The Federal Government has stated that in order to ensure that the incentive has the intended stimulative effect it will be offered only in provinces that maintain, or preferably, enrich existing fiscal incentives for tertiary production.

Prior to the National Energy Program, the income tax system allowed taxpayers to claim a deduction, called the depletion allowance, equal to 33 1/3 per cent of oil and gas exploration and development expenditures. Expenditures on enhanced oil recovery equipment earned depletion at a rate of 50 per cent of those expenditures. The National Energy Program modified the depletion allowances and introduced the Petroleum Incentives Program which is summarized in Table 2.

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* Appendix E draws mainly on the Brief presented by the Department of Energy, Mines and Resources to the Special Senate Committee on January 20, 1981.

Table 1

NATIONAL ENERGY PROGRAM: WELLHEAD OIL PRICES

	Oil Sands Reference Price*	Tertiary Recovery Oil** (15° API gravity)	Conventional Oil (38° API gravity)
		($/bbl)	
Jan. 1980	-	-	14.75
Aug. 1980	-	-	16.75
Jan. 1981	38.00	30.00	17.75
July 1981			18.75
Jan. 1982	41.85	33.05	19.75
July 1982			20.75
Jan. 1983	45.80	36.15	21.75
July 1983			22.75
Jan. 1984	49.85	39.35	25.00
July 1984			27.25
Jan. 1985	54.10	42.70	29.50
July 1985			31.75
Jan. 1986	58.55	46.20	35.25
July 1986			38.75
Jan. 1987	63.20	49.90	42.25
July 1987			45.75
Jan. 1988	68.30	53.90	49.25
July 1988			52.75
Jan. 1989	73.75	58.20	56.25
July 1989			59.75
Jan. 1990	79.65	62.85	63.25
July 1990			66.75

* Subject to cap of international price.

** In later years, the price for tertiary recovery oil will depend upon the price for conventional oil. As the price for conventional oil approaches that for tertiary recovery, price differentials will develop to reflect quality differences, i.e., the cost of upgrading. The price of tertiary recovery oil will never be less than the price for conventional oil of a similar quality.

Table 2

DEPLETION ALLOWANCES AND INCENTIVE PAYMENTS FOR OIL AND GAS EXPLORATION AND DEVELOPMENT

	Conventional Areas		Canada Lands		Major Projects Receiving Incentive Prices		
	Exploration	Development	Exploration	Development	Development	Enhanced Recovery Machinery and Equipment	Bituminous Sands Equipment
	(percentage of qualifying expenditures)						
System of Depletion Allowances							
Individuals and corporations	33 1/3	33 1/3	33 1/3	33 1/3	33 1/3	50	33 1/3
System of Incentive Payments and Depletion							
Rate of depletion allowance							
for corporations							
1981	33 1/3	0	33 1/3	0	33 1/3	33 1/3	33 1/3
1982	20	0	33 1/3	0	33 1/3	33 1/3	33 1/3
1983	10	0	33 1/3	0	33 1/3	33 1/3	33 1/3
1984 and after	0	0	33 1/3	0	33 1/3	33 1/3	33 1/3
for individuals	Depletion no longer earned by individuals as of 1981						
Rate of incentive payment							
for individuals and corporations at least 75% Canadian-owned*							
1981 and after	35	20	80	20	20	20	20
for corporations 50-75% Canadian-owned*							
1981	0	0	35	0	0	0	0
1982	10	10	45	10	10	10	10
1983	10	10	45	10	10	10	10
1984	15	10	50	10	10	10	10
for corporations under 50% Canadian-owned							
1981 and after	0	0	25	0	0	0	0

* To qualify for incentive payments, corporations with 50 per cent or more Canadian ownership must also be Canadian-controlled.

A modification to the Canadian ownership rules pertaining to the new incentive payments was announced on February 16, 1981.

A new Petroleum and Gas Revenue Tax is to be imposed with the rate set initially at 8 per cent of net operating revenues related to the production of oil and gas, including income from oil and gas royalty interests. Deductions for exploration and development expenditures, capital cost allowances, royalties, and interest will not be allowed. Operating costs, including the cost of materials injected into a reservoir for oil recovery enhancement will, however, be an allowable deduction. The tax will not be deductible for income tax purposes and will be applicable to net operating revenues earned in 1981 and thereafter.

A new Excise Tax on Gas and Natural Gas Liquids of 30¢/Mcf (thousand cubic feet) was instituted effective November 1, 1980 except for export sales, which become subject to the tax on February 1, 1981. It will increase by a further 15¢/Mcf on July 1, 1981 and by 15¢/Mcf on January 1, 1982 and January 1, 1983. Gas reinjected into a natural reservoir in Canada for purposes other than storage, would not be subject to the tax. Gas injected into a reservoir to displace a solvent bank in a miscible flood project, for example, would not be subject to the tax. Natural gas liquids (ethane, propane and butane) will be taxed, when they are first removed from a gas processing or reprocessing facility, initially at a rate equivalent to 30¢/Mcf of natural gas. This tax rate will rise to the equivalent of 75¢/Mcf by January 1, 1983. An exemption from this tax for NGLs used in a miscible flood project was announced on January 22, 1981.

(2) Provincial Fiscal Systems

Alberta

Alberta crown production of oil is subject to two royalty schemes, for 'old' and 'new' production, with lower royalty rates applying to new production. New production is essentially that portion of production from a pool developed after the beginning of 1974. Additional production from an enhanced recovery scheme approved after January 1, 1974 qualifies as new oil.

Where an enhanced recovery scheme has been approved by the Alberta Energy Resources Conservation Board and if the Minister of Energy and Natural Resources is satisfied that the cost attributable to the implementation and operation of the enhanced recovery scheme exceeds the cost of a waterflood scheme in the same field or pool, further royalty relief may be granted. This relief takes two forms. A royalty rebate may be allowed for the cost of natural gas liquids injected for oil recovery enhancement in a field subject to a maximum in any month of 5 per cent of the royalty payable on petroleum produced from the field in that month. In addition, a deduction is allowed from gross oil revenue otherwise subject to royalty in respect of the cost of incremental capital, injected materials, other incremental costs of operating the enhanced recovery project and on overhead allowance equal to 10 per cent of the incremental costs to allow for overhead and interest expense during construction.

Saskatchewan

The Saskatchewan fiscal system consists of two parts: A Crown Oil Royalty payable on Crown lands, and an Oil Well Income Tax payable on both Crown and freehold production.

Saskatchewan also differentiates between old oil and new oil in determining the royalty payable to the Crown. 'Incremental oil' is the incremental oil produced after the year 1973 from an oil pool with respect to a new or expanded waterflood project, thermal recovery project or other enhanced recovery project and is considered as new oil for purposes of royalty calculations. The royalty rate on incremental oil from enhanced oil recovery projects is 70 per cent of the royalty rate on old oil.

All oil well income is also subject to the oil well income tax with the exception of royalty revenues to mineral owners of producing tracts aggregating 1,280 acres or less. The oil well income tax rate is presently 59 per cent. The amount of royalty paid to the Crown is deducted from the oil well tax otherwise payable. Deductions for the purpose of determining the income subject to the tax are permitted under the system for several classes of expense. One of these classes is the 'new oil allowance' which is based on the proportion of the person's revenue from new oil production relative to revenue from all oil production, subject to a maximum of 30 per cent of total oil well income. This deduction provides an incentive for increased production of new oil.

Every barrel of oil a producer generates in Saskatchewan is credited with 80¢ in an approved expenditure grant account. For each dollar expended on qualified activities, one of which is the drilling of tertiary recovery wells, 75¢ is remitted to the investor from the Saskatchewan Heritage Fund.