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UNDERGROUND DISPOSAL OF CARBON DIOXIDE

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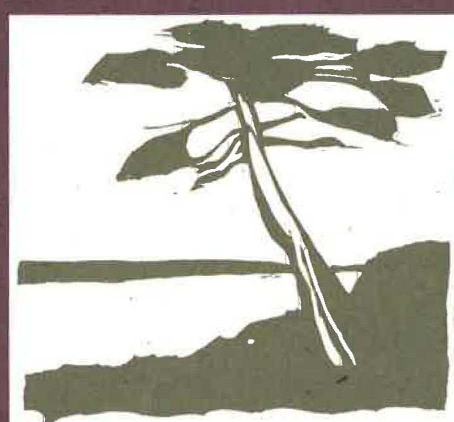

Imperial Oil

IMPERIAL OIL LIMITED

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

Imperial has examined direct steps to remove carbon dioxide (CO_2) from the atmosphere employing so-called CO_2 "sinks". In particular, the company has examined two options which are highly relevant to its business and unique expertise.

The first of these involves injection of CO_2 into subterranean reservoirs containing oil and gas to enhance the recovery of these hydrocarbons. The second involves straight disposal by injection of CO_2 into deep subterranean formations such as saline aquifers. These options are only relevant where there are large, single "point" sources of CO_2 emissions which can be captured, processed and pipelined over a reasonable distance to injection wells that access subterranean formations.

This study focuses on CO_2 emission sources in Alberta where there are a number of large coal-fired power generation facilities, oil sands production and refining plants and other fertilizer and petrochemical plants. CO_2 emissions from these facilities are about 142,000 tonnes per day - about 42 percent of Alberta CO_2 emissions and 10 percent of the Canadian total.

Imperial estimates that it would be technically feasible to develop, over a five to 10 year period, the infrastructure to permanently dispose of up to 50,000 tonnes per day of CO_2. This represents about a third of the aggregate emissions from the larger point sources in Alberta or about 3.5 percent of Canadian CO_2

emissions. Capital costs would be about $7.5 billion with annual operating costs of up to $225 million for 10 plants.

For the hydrocarbon recovery option, the net cost of CO_2 disposal could range between $15 and $50 per tonne of CO_2, depending on incremental recovery of hydrocarbons to offset some of the disposal costs. For the straight disposal option, net costs could range between $35 and $45 per tonne of CO_2.

Imperial's preliminary work shows that there are large net costs to society in the underground disposal of CO_2 which need to be carefully assessed and weighed with other alternatives. In this regard, Imperial is currently participating in collaborative studies with other industries and government agencies in Alberta and Saskatchewan that will more definitively assess the costs and benefits of CO_2 disposal for specific projects. These studies will also identify areas for joint technology development where this is appropriate.

Imperial is conducting a follow-up program in its own operations to identify and evaluate the most attractive CO_2 injection projects as part of a larger program to identify enhanced oil recovery opportunities. This study could lead to CO_2 pilot demonstration projects, depending on the findings.

INTRODUCTION

As a significant Canadian producer, marketer and consumer of fossil fuels, Imperial Oil Limited is committed to participating in the public policy debate concerning the issue of global climate change and presented the company's perspective in Imperial's "Discussion Paper on Potential Global Warming" which was released in 1990.

The paper follows up on one of seven commitments outlined in the discussion paper by examining the underground disposal of carbon dioxide (CO_2), one of the greenhouse gases. The precise commitment is "to determine the technical and economic potential for carbon dioxide "sinks", or mechanisms to remove carbon dioxide from the atmosphere, such as underground injection into oil bearing reservoirs to support enhanced oil recovery operations."

From Imperial's perspective CO_2 sinks are a relevant option to all industries that generate significant amounts of CO_2 at a plant site. This paper does not yet incorporate technical input from government, academic, and industry stakeholders since similar studies are still evolving. Instead, the study results reflect only Imperial's understanding at this time. Conclusions are directional and subject to modification as Imperial collaborates with others in follow-up studies.

CO_2 Emissions Sources

Imperial estimates that in 1988, Canada's CO_2 emissions from fossil fuel combustion were 529 million tonnes or about 1.45 million tonnes per day. Since numerous options for underground injection exist in Western Canada in close proximity to significant emissions sources, and since Alberta's estimated production of 340,000 tonnes per day represents nearly a quarter of the total for Canada, this study focuses on the Alberta sources.

Alberta's energy related CO_2 generation originates, in decreasing order, from industrial sources, power generation, transportation and heating. Even through most of the emissions are widely distributed, significant industrial and power generation volumes are concentrated in a relatively few sources from which the CO_2 can be gathered. Table 1 summarizes the types and locations of some of the larger sources. In the near to medium term, the collection of CO_2 that is otherwise vented to the atmosphere from these supply points would likely be the least costly, should collection become necessary.

CO_2 Disposal Options

Two broad options exist for disposal into underground reservoirs: CO_2 can be injected into deep subterranean formations, either to enhance oil and gas production operations or strictly for disposal. For the former option, an extensive pipeline network would be required. Table 2 summarizes the options considered for hydrocarbon recovery and for non-hydrocarbon disposal.

Depending on the disposal option, the concentration of CO_2 would need to be controlled. For example, enhanced oil recovery (EOR) opportunities generally require nearly pure CO_2. This would

Table 1

Alberta Industrial and Power Generation Point Sources of CO_2

Source	CO_2 Emissions (1000 tonnes/day)	% of Alberta Emissions	Examples
Power Generation	97	29	Wabamun, Sundance
Oil Sands	30	9	Syncrude, Suncor, Cold Lake
Fertilizer & Petrochemical	15	4	Redwater, AGEC, Medicine Hat, Union Carbide
TOTAL	142	42	

Table 2

Potential CO_2 Removal Options

	Additional Hydrocarbon Recovered % OOIP	Additional Hydrocarbon Recovered %OGIP	Net CO_2 Retained % HCPV	Estimated Disposal Volumes 1000 Tonnes/day	% of Alberta Emissions
I. Hydrocarbon Recovery Schemes					
A. Conventional Oil/Gas Operations				15-30	5-10
Pressure Maintenance Gas Cycling		5-20	80		
Enhanced Gas Recovery		10-50	60		
Immiscible Oil Recovery					
(i) Vertical	6-11		8		
(ii) Horizontal	5-10		8		
B. Miscible Enhanced Oil Recovery (EOR)				15-30	5-10
Miscible Displacement					
(i) Vertical	20-30		70		
(ii) Horizontal	6-12		8		
Miscible Chase Gas					
(i) Flue Gas or Nitrogen	2		70		
(ii) CO_2	2		70		
II. Non-Hydrocarbon Schemes			100	0-50	0-15
TOTAL				~50	~16

require some processing, since CO_2 is typically available in concentrations of 10 to 15 percent by volume in the stack gas from power plants. In addition, steps would have to be taken to limit corrosion from the CO_2 stream in pipelines and other facilities.

At the application end, in EOR operations, the CO_2 is injected into the subterranean reservoir to displace additional oil or gas from the rock pore spaces which would not be recovered in conventional operations. Since some of the injected CO_2 will return in the produced oil or gas, it will also be necessary to remove this CO_2 from the hydrocarbon and recycle it back to the reservoir.

In terms of hydrocarbon recovery, opportunities exist to utilize CO_2 to contribute to conventional oil and gas and to miscible EOR operations. The potential recovery benefits, and the amounts of CO_2 retained in the reservoir compared to the amounts injected, can vary significantly.

Table 2 provides estimates of the hydrocarbon recovery benefits as a percentage of the original-oil-or gas-in-place (OOIP or OGIP). Also the net retention of CO_2 in the subterranean formation is estimated as a percentage of the original hydrocarbons in place or hydrocarbon pore volume (HCPV).

Estimates of technically feasible disposal volumes for each type of operation are also provided in Table 2. For example, while approximately 65,000 tonnes per day of hydrocarbon gases (such as methane, propane and ethane) are being injected to provide pressure maintenance in conventional oil production operations in Alberta, it is estimated that perhaps as much as 25 percent of this could be replaced by CO_2. A similar volume of CO_2 could be applied to the other types of conventional oil and gas operations, suggesting a total consumption of 15,000 to 30,000 tonnes per day. It is also technically feasible to inject an equivalent amount of CO_2 for miscible for operations as shown on Table 2.

The second major disposal option involves straight injection into deep subterranean saline aquifers. The effectiveness of this type of disposal will depend on the extent of chemical reactions between the saline formation water and the CO_2 forming insoluble carbonates. On the one hand this could enhance the disposal capacity but it can also plug off access to the aquifer formation in the wells used for disposal purposes. As a result, mixing and solids removal at the surface might be required to mitigate the plugging effects.

In summary, it would appear technically feasible to develop, over a five to ten year period, the infrastructure to dispose of up to 50,000 tonnes per day of CO_2--CO_2 which would to some extent replace the valuable hydrocarbon injectants currently used in existing and future projects. These volumes, while fairly minor when compared to overall Canadian emissions, represent a significant reduction in Alberta industrial emissions. But this reduction comes at a significant cost.

Cost and Benefit Assessment

To evaluate the net cost of this type of CO_2 disposal, it is necessary to develop estimates of disposal costs and the revenues from increased hydrocarbon recovery benefits which partially offset these costs. It is assumed that CO_2 disposal will, wherever possible, be associated with hydrocarbon recovery or, where straight disposal is involved, the most suitable, but not necessarily the nearest, aquifers will be used. It is envisioned that an infrastructure of gathering, transportation and field facilities will be required. In this context, the scenario developed to estimate costs and revenues envisages the implementation of 10 schemes each handling 5,000 tonnes per day, with start-ups staged over a five year period. It is assumed that each project will last 20 years, for a combined project life of 25 years.

Capital costs will include that required for facilities to purify, treat, compress and pipeline CO_2 and those required to purify hydrocarbon products to enable recycling of CO_2. These costs are estimated to total \$750 million to \$1,250 million (1990\$) per scheme. The \$750 million cost assumes that collection of the nearly pure CO_2 from the oil sands and fertilizer plants will occur first. Then, as an infrastructure is developed and technology is advanced, the higher costs required to remove and concentrate CO_2 from flue gas streams will be offset to some extent. Therefore it may be possible to restrain the growth in capital costs for each scheme to the \$750 million level. As a result, a capital investment of approximately \$7.5 billion would be required to reduce emissions to the atmosphere by about 50,000 tonnes per day (about 15 percent of the Alberta CO_2 emissions).

A 50,000 tonne per day objective would be an ambitious and costly first step and long lead times would be required to design and implement recovery-related projects of this magnitude. It is expected that three to five years would be required to implement the first projects and to initiate development of a transportation infrastructure. Assembling the necessary consortium of stakeholders would extend the time frame.

Operating costs for each of the 10 schemes over the 25 year life of the project would be about \$22.5 million per year. Combined capital and operating costs of the whole project, using a cost of service basis, would translate into a disposal cost of about \$65 to \$75 per tonne of CO_2 (\$3.50-\$4.00/mcf) for hydrocarbon related projects. Some of these costs are offset by the additional revenues generated from increased hydrocarbon recovery and sale. For straight disposal projects requiring fewer facilities and lower transportation expenditures, the expected costs could be reduced by nearly half.

An assessment of hydrocarbon recovery benefits that could offset these costs can be based on estimating the efficiency of a technically successful large-scale EOR scheme. Such schemes, on a net basis that allows for recycling, could require between 0.4-0.5 tonnes of CO_2 (7-10 mcf) per barrel of oil recovered. A few unique and small project field tests in Western Canada have demonstrated that better efficiencies are achievable. However, in considering projects of the magnitude proposed, opportunities will be less favourable and such expectations would be inappropriate. Therefore, using a requirement of 0.4-0.5 tonnes per barrel, and depending on price growth over the life of the project, the net cost of CO_2 disposal might be reduced to between $15 and $50 per tonne ($1 and $2.75/mcf). These offsetting revenues correspond to a benefit of between one quarter and two thirds of gross costs. These results are summarized in Table 3.

By Imperial's estimates, significant oil price growth and improved technology, leading to increased CO_2 utilization efficiency, would be required to exceed a break-even scenario. As a consequence, the hydrocarbon recovery projects would not be self-supporting. Further, there would likely be a combination of hydrocarbon recovery and straight disposal projects, with no offsetting benefits, resulting in significant overall net costs -- costs which would need to be shared not only by contributors of the emissions, but more broadly by society.

Relative Contributions of CO_2 to the Greenhouse Effect

Significant expenditures and commitment are required to reduce current Alberta CO_2 emissions by only 15 percent by injection into underground reservoirs. Further, the benefits of CO_2-based hydrocarbon recovery schemes do not appear to be economic in themselves. So that the potential for CO_2 disposal can be placed in an appropriate context and priorities are better understood, it

Table 3

Projected Costs and Benefits of CO_2 Disposal

	\$/tonne of CO_2	\$/MCF of CO_2
Hydrocarbon-Recovery Projects		
CO_2 Supply Cost	65-75	3.50-4.00
Hydrocarbon Recovery Benefits	25-50	1.25-2.50
Net CO_2 Supply Cost	15-50	1.00-2.75
Straight Disposal		
Net CO_2 Supply Cost	35-45	1.75-2.25

is important to examine and compare this approach to reducing greenhouse gas emissions with others, such as reducing emissions of other greenhouse gases (i.e. methane and CFCs) from their sources.

Current Initiatives

As stated at the outset, this paper presents the experience and expertise of Imperial. Other inputs, from industries, governments, academia and other stakeholders will be required to achieve a more comprehensive assessment. Imperial is currently participating in collaborative studies with other industries and government agencies in Alberta and Saskatchewan that will more definitively assess the costs and benefits of CO_2 disposal for specific projects and will identify areas for joint technology development where this is appropriate.

Imperial is also conducting an in-house program to identify and evaluate the most attractive opportunities for CO_2 injection projects to enhance hydrocarbon recovery in its operations. This study will be completed by mid-1991 and, depending on the findings, could result in pilot demonstration projects.

These types of initiatives will better position industry and the nation to exploit CO_2 disposal opportunities should this become desirable.

Conclusions

1. Disposal of 50,000 tonnes per day of CO_2 is technically feasible in the near term if a combination of enhanced

hydrocarbon recovery and straight disposal schemes is implemented.

2. Capital expenditures of at least $7.5 billion would be required over a five to 10 year period; combined with operating costs, the cost for disposal of CO_2 would be in the range of $65 to $75 per tonne of CO_2 for hydrocarbon recovery projects and $35 to $45 per tonne for straight disposal projects.

3. Increased revenue from enhanced hydrocarbon recovery projects is not expected to fully offset the associated CO_2 injection costs, but could reduce net disposal costs for these projects to $15 to $50 per tonne.

4. Significant investments and a high degree of collaboration among stakeholders would be required to achieve a relatively minor impact in reducing CO_2 emissions through implementation of such disposal schemes.

5. Should international strategies evolve to reduce CO_2 and other greenhouse gas emissions through steps that are uneconomic in their own right, options such as the disposal of CO_2 by underground injection require further technical and cost assessment. In particular, opportunities to reduce other greenhouse gas emissions need to be compared to ensure the strategies adopted achieve the broadest benefits for society.