# CANADIAN OIL POLICIES AND NORTHERN TIER ENERGY ALTERNATIVES

839



## HEARING

BEFORE THE

## JOINT ECONOMIC COMMITTEE
## CONGRESS OF THE UNITED STATES

NINETY-FOURTH CONGRESS

SECOND SESSION

SEPTEMBER 13, 1976

Printed for the use of the Joint Economic Committee

U.S. GOVERNMENT PRINTING OFFICE

83-836 O WASHINGTON : 1977

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402

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# CANADIAN OIL POLICIES AND NORTHERN TIER ENERGY ALTERNATIVES

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**MONDAY, SEPTEMBER 13, 1976**

CONGRESS OF THE UNITED STATES,
JOINT ECONOMIC COMMITTEE,
*Washington, D.C.*

The committee met, pursuant to notice, at 9:30 a.m., in the assembly room, Federal Reserve Bank Building, Minneapolis, Minn., Hon. Hubert H. Humphrey (chairman of the committee) presiding.

Present: Senator Humphrey.

Also present: George R. Tyler, professional staff member.

## OPENING STATEMENT OF CHAIRMAN HUMPHREY

Chairman HUMPHREY. We will proceed with the Joint Economic Committee's field hearing on energy questions, one of several conducted by the committee this congressional session.

We have a number of interested parties here at the hearing. Regretfully, though, some of them will not have the opportunity to testify. But might I say we welcome any statement these parties may wish to make for the record. We will keep the record open for a couple of weeks for that purpose.

The purpose of this hearing is to explore the energy situation over the next several years in the northern tier States, stretching from Wisconsin and Minnesota to the State of Washington. There is a very special interest here in the northern tier specifically relating to the availability of Canadian oil supplies. And there has been a good deal of conflicting information disseminated. I thought it would be beneficial that we would bring together at this time a number of persons concerned with this situation—persons in the refineries, at the Government level, from the Federal Energy Agency, from the State Department and from other departments of the Government to clarify the energy picture for this region.

At a similar hearing last fall, the committee heard that the northern tier was confronting an energy crisis of its own, more threatening and more pervasive than the larger energy crisis faced and still facing our entire Nation.

The committee heard at that time that the northern tier's economy had been placed in jeopardy by the newly announced Canadian oil export policy, a policy designed to promote Canadian energy independence—and, I might add, understandably Canadian oil conservation—but a policy which also called for an end by 1981 to Canadian oil exports to the United States, and especially to the northern tier States.

I think it is important that we keep in mind the year 1981 because the Canadians mean to hold to that date from all that they have told us. There tends to be in some circles a feeling that maybe they will adjust the date. That is unrealistic. I see no indication that there will be an extension of that deadline.

Since that earlier hearing, some progress had been made by northern tier oil companies in developing and evaluating alternatives to replace this Canadian oil.

Mr. Zarb, who is here today with us, and his staff at the Federal Energy Agency, have been extremely helpful in the development and implementation of a priority oil allocation system. This system is now in operation, and is designed to insure that the most Canadian-dependent refineries have first call on available Canadian oil. Northern tier, and especially Minnesota consumers should be, and are, most appreciative of the excellent and quick FEA work in developing this program. I want to express my thanks publicly to Mr. Zarb for his extra efforts on our behalf.

In addition, certainly the most optimistic event since last fall is the recent announcement by the Williams Pipeline Co. that they will construct a new line from Iowa to the Twin Cities. When completed next year, this line will supply almost 30 percent of the oil now being phased out by Canada. This is a positive action and a very welcomed one.

Let me see if I can summarize the oil situation today as I see it.

Within 4 years, Canada will cease supplying us oil that now comprises 2 of every 3 gallons of gasoline and heating oil used in Minnesota and the northern tier States. We have very little time to replace that oil, and replacement will not be easy, as we have already discovered.

Minnesota and the northern tier are at the end of domestic pipelines. As a result, new pipelines must be built, and that takes time. It also takes a great deal of capital. These new pipelines are absolutely essential if we are to have replacement oil.

Two major proposals exist now to lay pipelines into Minnesota: The northern tier line across the United States to Minnesota from Puget Sound, and the TransProvincial line across Canada from Kitimat to Edmonton and thence to North Dakota. More remote possibilities include the further expansion of the Williams pipeline system or looping of the Canadian Transmountain line.

All of these alternatives will be costly. All of them require 2 or 3 years to construct. Might I add that from our own experience, we've found that environmental problems as well as technical problems frequently alter promised construction time schedules. One or a combination of these pipeline proposals should be ready by 1980 or 1981.

That leaves us with a 3- or 4-year gap, a period over the next 3 or 4 years when none of these permanent pipeline solutions will be available. Yet Canadian oil exports will be declining sharply each year, threatening the northern tier with oil shortages.

This coming winter, severe weather could leave Minnesota, for example, as much as 50,000 barrels a day short if predicted Canadian curtailments occur. That is a very frightening figure.

Completion of the Williams pipeline in 1977 from Iowa should prevent shortages next winter. Yet in 1978 and 1979 Minnesota and the entire northern tier will once again face oil shortages.

A variety of temporary or ad hoc solutions to bridge the 1976–80 oil gap have been offered, including such things as oil swaps or exchanges between the United States and Canadian refineries, and barging or trucking oil into this region.

This hearing is designed to explore these and other solutions, to hear Federal, State and private industry spokesmen involved evaluate this near-term situation. We will also hear some testimony regarding the natural gas situation in our region. Here too, we face shortages from both Canadian and domestic interstate suppliers. And, I'm afraid, we will continue to face supply cutbacks until a reasonable, uniform price is established for both inter- and intrastate gas or until Alaskan gas becomes available to the northern tier.

With me is a member of the staff of the Joint Economic Committee, Mr. George Tyler. Mr. Tyler has specialized in energy questions for us. He has worked very closely with many of you here in Minnesota and, indeed, in all northern tier States. I have asked him to participate in the hearing as a member of our panel on this side of the table.

Leading off our hearing will be Mr. Frank G. Zarb, Administrator of the Federal Energy Administration.

I want to say again, Mr. Zarb, that the entire Northern Tier is grateful to you for what you have done thus far. We have a good working relationship, and I believe we can say here publicly that Mr. Zarb has walked the extra mile to try to be helpful to us in this part of the country.

He will be followed by Mr. John Millhone, director of the Minnesota Energy Agency; by Lawrence Raicht, Director of the Office of Fuels and Energy of the Department of State; by Mr. Vernon Jones, president of the Williams Pipeline Co.; and by Mr. George Thiss, executive director of the Upper Midwest Council.

Mr. Zarb, please proceed. I appreciate, as I said, your coming to us.

Mr. John Hill was here last year.

Mr. ZARB. Yes.

Chairman HUMPHREY. We want to say that he very ably represented your agency last year.

Mr. ZARB. Thank you. Mr. George Mehocic is with me here from Washington.

## STATEMENT OF HON. FRANK G. ZARB, ADMINISTRATOR, FEDERAL ENERGY ADMINISTRATION, ACCOMPANIED BY JOHN A. HILL, DEPUTY ADMINISTRATOR, AND GEORGE MEHOCIC

Mr. ZARB. Mr. Chairman, I appreciate the opportunity to appear here today, particularly to discuss an energy problem which is one of the very many this Nation faces in the year 1976.

It is particularly gratifying to speak within a group that recognizes that we have a problem that needs to be dealt with. So often I begin these presentations facing people who wonder whether we have a problem at all, but here appears real live proof that a problem does exist, and I can assure you it is one that is faced by the entire Nation. People of New England have no lesser a problem. People of southern California who have to worry about clean air and at the same time sufficient power have no lesser problems, and even the people of Texas, believe it or not, must now grapple with methods of importing coal, and the Southwest area is faced with the problem of sufficient power.

We have significant problems throughout the Nation, and we compliment you and the committee for continuing to have these hearings to keep in focus the specific situation faced here in the northern tier and the nature of the various solutions that might be pursued.

I am going to submit my prepared statement for the record, Mr. Chairman, since you have many witnesses and only several hours to hear them.

Chairman HUMPHREY. We will hear whatever you have to say.

Mr. ZARB. I will then be available for whatever questions you may want to present to me.

I will just briefly overview the content of my testimony.

It would appear at this point that there will be no problem with oil and natural gas availability in the northern tier this coming winter. We can also be corrected by weather conditions that are extraordinary or other disruptions that we do not presently anticipate. I must say, though, that our data to date would indicate that whatever shortage in oil that we have appears to be made up in refined products, and we do not see a shortage in this part of the country in this coming winter. The same is true of natural gas. There will be no curtailments in that last year they stayed with their commitment throughout the year. We had no extraordinary or anticipated curtailments.

The preliminary data that has been developed by the FEA and FPC, however, indicate that gas deliveries will be just about the same as last year's level; and given the amount of switching that we have had to alternate fuels and other conservation steps that have been taken, we anticipate that being adequate. Alaska gas, it is clear, will not be available in time to offset the decline in aggregate of oil and gas sources to this part of the country.

The FPC is currently evaluating three proposals to transport Alaskan gas to the lower 48 States. Their review will not be completed until March 1, 1977. The administration has presented a bill to speed up that review process and, more importantly, to speed up the completion process once the decision is made. I am certainly hopeful that Congress will see fit to pass that legislation before its October 2 recess. That is a critical piece of legislation. Alaskan gas, in any case, will not be available for 3 to 4 years after all the approvals are received, which gets us to an interim period which, I think, is very, very critical.

We have completed an allocation program for crude oil coming from Canada which gives us some time for refineries to substitute supply alternatives. We have conducted a study which indicates crude oil should be available to the northern tier refineries by late 1979. No Government action to aid that solution seems to be necessary at this time.

The FEA study is based, in part, on a contract done by Bonner and Moore. I understand the committee has access to that. We submitted our report to the Congress on, I believe, August 2. The contract provided valuable information that was used in our analysis. We are looking at a situation which will exist between now and 1980. My staff will have it ready for publication no later than the end of October.

With respect to the Williams Bros. pipeline, which has received some publicity and some discussion, it does appear, based upon a staff analysis, that that pipeline is necessary to avoid shortages not only in Minnesota but throughout the northern tier.

We have streamlined our own process to facilitate crude oil exchanges with Canada, still insisting on salvaging U.S. domestic oil. But we have had further discussions with Canadian officials, and it is our hope and objective to use not only domestic oil, but imported oil as well on our side of the exchange. We consider that to be very critical and a point which will be pursued very aggressively with the Canadian Government.

Mr. Chairman, I don't want to get into all the details because I'm not certain of the questions you really want me to answer, so rather than take up a lot of time with my talk, why don't we take up your questions.

Chairman HUMPHREY. Very good.

The central question on the matter of exchanges, Mr. Zarb, of course, deals with the Canadian Government's attitude on so-called off-shore oil exchanges. It is my recollection and understanding that insofar as on-shore exchanges involving domestic U.S. oil are concerned, Canadian officials seem to be understanding and cooperative. Is my information correct?

Mr. ZARB. That is completely correct, Senator. We have had thus far, as I recall, seven applications for export loans to effect exchanges. Six of those were approved at the FEA level. Three have been approved Government-wide and three are pending for completion of Government approval. There have only been seven submitted. The critical aspect in expanding the exchange agreement would appear to me to be the Canadian Government's willingness to accept off-shore oil as our part of the exchange. In my view, this is an extremely reasonable position for the United States to be taking. We spent a lot of years becoming committed to Canadian oil, Mr. Chairman. During all of those years there was no indication that we were going to face a 5- or 6-year cutoff.

I'm not criticizing the policy decision. Each nation needs to make its own firm decisions to achieve its independence. I only hope we get around to our own pretty soon.

It seems to me that the Canadian Government should be somewhat sympathetic due to the fact that for all those years we developed a long-term business relationship, and should be willing to be somewhat more flexible than they have been, to insure that the phase-out period anticipates and entreaties the sensitive aspects of our economy. It is my view that we should pursue that position very aggressively, and ultimately the reasonable views within the Canadian Government will prevail and they will permit off-shore oil as our part of the exchange.

Chairman HUMPHREY. What is going on in those negotiations and how are they being pursued?

Mr. ZARB. You have a State representative who will give you more detailed information. My staff participates in all of those negotiations. It is, of course, our objective to insure that this economy and others that are affected by Canadian crude are not disrupted during the period of our seeking out and implementing alternatives. If there is any one thing clear, it is this. Just as that nation has the ability to significantly reduce all of its imports within the next 10 years, this particular problem faced by the northern tier, this Nation has the capability of standing on its own two feet and getting its own job done within a reasonable period of time. All we are asking for is some reasonableness in phasing out a business relationship which existed for many years without any indication that we were going to have to face this kind of a schedule for phase-down.

Chairman HUMPHREY. As I understand it, the difficulty with expanding on-shore oil exchanges is limited domestic U.S. pipeline capacity, is that correct?

Mr. ZARB. That at the moment is correct. The pipelines have been stressed with respect to maximum volume levels, particularly with the extra flow of refined product.

Chairman HUMPHREY. Your agency has assigned the highest priority to northern tier refineries. Will your agency make every effort to see that all swap or exchange deals by first-priority northern tier refineries receive the go-ahead before any second priority refineries can engage in such exchanges? Isn't that the logical extension of your existing Canadian oil allocation program?

Mr. ZARB. On the surface, it would appear to be very logical. Wish we had that problem. We have had only seven requests for realistic exchanges. We have had 47,000 barrels a day, give or take a few 1,000, which is only a very small amount. I wish we had on our platter enough viable at the present time so that we could begin separating one from the other and having different categories. At the moment we don't have enough applications to make that judgment.

Chairman HUMPHREY. Why is that the case? In light of the fact that the Canadians are obviously going to be cutting off our oil, why do we not see more exchanges being initiated?

Mr. ZARB. I would say a combination of reasons.

One, we just talked about, the offshore question where people have determined ahead of time that offshore would not be acceptable so have refused and not submitted applications based upon that, so it makes good sense if we can clear up that one question. There are some economic questions here with respect to whether there is sufficient economic incentive for domestic producers to pursue that particular alternative at any given moment where there may be other alternatives that may have economic benefits to them.

Finally, I would expect the overall question of an old way of doing business beginning to break through new ways of doing business with new transportation systems and new participants in these transactions just takes some time. As always, the old question is there, Mr. Chairman, the sight of the gallows helps to focus the mind and the more serious the condition becomes the more people will begin to focus on real solutions.

Chairman HUMPHREY. Is there any problem with the major oil companies, being somewhat reluctant to work out exchanges that might be beneficial to the independents?

Mr. ZARB. I have no specific evidence of that. If there is such a situation where there appears that kind of reluctance, I would assume somebody would let me know of it.

Chairman HUMPHREY. I would too.

Mr. ZARB. I would certainly like to have that kind of information.

Chairman HUMPHREY. Now, there are two or three long-term pipeline alternatives that are always discussed, as you have indicated in your prepared statement, to supply oil to the northern tier area after 1979 and 1980. Your agency, I understand, has been evaluating these alternatives.

Are you prepared now to give us any indication of what appears to be the best route?

Mr. ZARB. I'm really not, Mr. Chairman. As you know, we are studying this—we seem to do a lot of studying in Government—but it always seems to be a requirement before we can recommend public policy because it is hard enough to get public policy after you have studied it. We are looking at two aspects; absolutely the first is getting oil into the northern tier in view of the fact that it faces an extraordinary shutoff from one of our trading partners. The other is getting Alaska oil away from the west coast and ensuring that it is delivered to the interior of the country as was the congressional intent when the Alaska pipeline was built. At the moment we are laying out alternatives for getting the oil away from the west coast into the interior and at the same time the best alternatives for serving the northern tier.

There appears a great deal of overlap in those two questions although there is not exclusive overlap. I would expect that between now and certainly the end of the year we will not only have laid out our options, we will have taken comment from not only this part of the country but from some folks in California who feel they have a stake in this question and some folks in Alaska, and then publish for the Congress a final report of all the options, all the information calculated, and a recommendation from the administration as to the best possible answer.

The Alaska draft, as a matter of fact, is due this week. I made a commitment that, once that draft was completed, I would read it. I would make it public, and I would leave it open for a 4- to 6-week period for comment not only from various State officials but from others, and we would still in mid to late November produce a final report with recommendations from our perspective.

Now, keep in mind that, while we are making recommendations, we will by no means have the authority to implement them.

Chairman HUMPHREY. We have, as you mentioned, a copy of the report,[1] "Petroleum Supply Alternatives for the Northern Tier States Through 1977." I notice that in the major conclusions summary in section 2, one of the things they point out is that the northern tier can't be viewed as a single entity for the purposes of analysis or regulation. The study then breaks the region down into four different areas. If you put them all together, there appears no shortage for 1977. But you come over to page 2–1 of section 2, titled "Major Conclusions," it reads as follows: "Minnesota, Wisconsin, northern Michigan and eastern North Dakota: existing spare pipeline capacity for crude oil and products is insufficient to meet the demands in this area when Canadian crude imports decline to levels projected for 1977."

The study makes note later that the Williams line can be very helpful to the Twin Cities. It says that crude oil can be made available to Min-

[1] See report referred to beginning on p. 18.

neapolis-St. Paul refineries through the projected expansion of the Williams pipeline in late 1977, and they point out that you can use barges and so forth.

Then at the bottom it says: "The Williams expansion, however, will be of only limited help to the Superior, Wis., and Wrenshall, Minn., refineries and of no help at all to the Mandan, N. Dak., refinery. Barges would also be of no help for any of these three refineries. The only solution to short-term crude supply problems in Superior, Wrenshall and Mandan, other than exchanges, appears to be a very expensive one, Williams pipeline in late 1977, and they point out that you can use the use of unit trains."

In the beginning there, I would like your commentary on what is meant by the statement, "that existing spare capacity for crude oil and products pipeline is insufficient"? How do you define insufficient?

Mr. ZARB. Well, the quote you just read came from the bottom of the Bonner and Moore study. It's been a very helpful study. We are still completing evaluation of it. There appear to be certain supplements we are not going to completely agree with.

Chairman HUMPHREY. Your agency may not agree with this study you contracted for?

Mr. ZARB. Yes, sir. I'm not suggesting that there are any major defects, but there are elements of it which we don't agree with, and there is a particular conclusion that we don't agree with.The fact is in terms of pipeline capacities with respect to being able to move crude and refined products, there is capacity to move certain streams. Some of the plans underway or anticipated to be underway can alleviate those difficulties in our opinion.

I will stand on my original statement. I don't anticipate a shortage of oil and oil refined products taken together in this part of the country in the next year. I don't mean to take away from the size of the problem by making that statement. We seem to continue to live year to year, not only in this issue but in some others. Of course, if you permit me a moment for a small commercial, it only further emphasizes the need for this Nation to get on with its own comprehensive energy policy because this is only one of many problems which I have to testify to around the country.

Chairman HUMPHREY. There are many questions here, Mr. Zarb. But I want to pose the question, how can we make offshore oil swaps or exchanges more attractive to the Canadian Government? What can we do to loosen up their attitude?

Mr. ZARB. I'm not sure whether you are suggesting a 2 by 4 that we have in our closet, which is an approach that I have always perferred with respect to our total energy relationships around the world, particularly in the Mideast; on the other hand, in this particular case it's going to be a question of negotiation. The Canadian have set themselves a very reasonable national goal, one that I would use if I were laying out their particular program. On the other hand, it seems to me that we must continue to lay out the following: We have had important trade relationship between our two nations for a good many years. Those relationships have been based upon trust and certain code of commercial conduct that has been excellent. I would hope that those decisionmakers in Canada, seeing that we are taking the necessary steps to cure our long-term situation—and we are, not only here, but as a nation—will conclude that, by allowing offshore exchange agreements, they are in no way committing themselves to long-term commitments to Mideast oil which must be their primary concern.

Beyond that, we have to take a very serious look at our own domestic policies to insure that we are providing the right incentives so that people will elect that option when that option is available to them.

George just pointed out to me, and it is a good point, the more we spell out our own intent to ultimately stand on our own two feet and not depend upon Canadian oil for a long period of time, the more they are going to agree with more flexible long-term solutions.

Chairman HUMPHREY. As I gathered from your testimony thus far, you say unless there is unusually severe weather—I think that caveat has to be put there—that you foresee no shortage of either gas or oil in 1977, is that correct?

Mr. ZARB. Yes, sir. With some strain but there is a good conclusion.

Chairman HUMPHREY. After 1977, what's the picture that you see?

Mr. ZARB. When 1977 and 1978 becomes a critical period, we will in our analysis to be published within the next month analyze the various options available to us to cure that particular period. Based upon the preliminary staff data that I have looked at, I'm confident that, with the right steps, we can avoid any massive economic disruption due to shortfall of oil or gas in this part of the country during that particular period.

It is going to be a workout, Mr. Chairman. There appear to be no two ways about it. But, if we stay on it as we have and as you have, it is my view that we are going to be able to put together the right combination of things, including this potential Williams Bros. Pipeline, to insure that we avoid any catastrophic result.

Of course if we have a very wet fall there where farmers have to use——

Chairman HUMPHREY. Not much danger of that this year.

Mr. ZARB. Not right here, but I am talking about nationwide.

Chairman HUMPHREY. Yes, sir.

Mr. ZARB. We can have temporary shortages of some seriousness.

Chairman HUMPHREY. You are speaking of 1978?

Mr. ZARB. 1978, 1979, and 1980.

Chairman HUMPHREY. Doesn't this depend, however, on the offshore oil exchanges?

Mr. ZARB. No question in my mind that expanding the overall exchange can help minmize the size of this problem. I don't think we ought to examine only the Canadian's reluctance to accept offshore. I think we have to examine, and we are, I know, within FEA, whether there are appropriate incentives in the supply.

Chairman HUMPHREY. Changing the subject now, the concern that I have had is that any of these long-term alternatives will take a good period of time to complete. Is it not a fact that there appears a considerable amount of negotiation that has to take place, not only with the central government in Canada but with the provincial governments before the Kitimat-Edmonton line is ready?

Mr. ZARB. No question but what that's true. In our Nation, to pick the U.S. preferred line, we have to deal with concerns of Alaska, concerns of the west coast States and the Far West and the concerns of the northern tier. So we have the same problem as they do.

It would seem to me, however, that once we have determined the best solutions from our standpoint, we should be in a much better position to sit down and negotiate not only the Federal level problems with the Canadians, but also their provincial questions.

Now, if any of those questions present some obstacles that would significantly delay the U.S. programs, it would be my view that we would have to shift away from such options to those that might not be economically attractive in the first instance, but will deliver an answer to the problem in a short length of time. So I don't promise that we will spend too much time with the diplomatic part of the equation.

Chairman HUMPHREY. The Kitimat-Edmonton connection has been talked about a great deal in this part of the country. Do you think that line can be completed by 1979–80?

Mr. ZARB. I would say 1980 is the earliest possible date, Mr. Chairman, that is, putting a sizable optimism factor into the schedule, given our experience with delays that are created in construction of such enterprises.

Chairman HUMPHREY. And legal problems.

Mr. ZARB. They are the major delays.

Chairman HUMPHREY. And what about the northern tier line across Montana?

Mr. ZARB. I guess I'd stay with 1980 for all of those alternatives, give or take a year, once the decisions are made. Of course what's most important is get the decisions made and then to have an appropriate process, similiar to the way the Congress solved the Alaska pipeline issue, ultimately, after years and years of wasting time.

Chairman HUMPHREY. The reason I ask these questions about dates is because I have a stack of material in my office this high [indicating] that Mr. Tyler and others have put together. I think there appears to be a good deal of optimism out here in Minnesota—I might just as well lay it on the table—that somehow or other this whole thing was going to fall into place here in a couple of years. I personally have not been that optimistic and I have tried to express that to some of the people here who are vitally concerned at the State level and at the refinery level.

I hope that we will see realized the pipeline construction program and the financing program in a timely fashion. I hope that the Canadians will be kind and considerate. And, I hope the lawyers won't interfere. But in my experiences—even with a power line a utility is trying to bring across Minnesota from North Dakota—there seems to be quite a big problem, taking large construction projects successfully through the judicial process, the legislative process, and the administrative process, the potential for delay is enormous.

If that is the case and we are not going to have Canadian oil exports after 1981, don't we get right down to the bedrock necessity that these offshore oil swaps are the major feature of our relief?

Mr. ZARB. Well, you know, I have answered that question before and I have answered it positively. I'm somewhat compelled by the total voluntary constraints even in that particular category. I think at maximum levels there is an effect of 250,000 barrels a day in such exchange agreements and, given our earlier experience, I think that's going to be somewhat difficult to achieve, Mr. Chairman.

Chairman HUMPHREY. May I just interrupt to say I don't think that offshore swaps are the total answer but it is perfectly obvious that it has to be a part of the answer and the major part of the answer to bridge the upcoming gap period. I'm talking about the uncertainties of the construction, the financing, the environmental problems, the legal problems, all of the many problems that come into play with a massive construction project such as we are contemplating in any of these pipelines.

Mr. ZARB. The answer to your question is "Yes." The answer to your observation, I agree with it. Running the risk of again being accused of using scare tactics, I would say that, if we don't have one of these long-range programs completed by 1981, we are in trouble, in deep trouble, so I would suggest that in the event we continue to face the kinds of difficulties that you are articulating, ultimately we are going to have to write congressional legislation to insure that they no longer are permitted to delay things beyond the danger point; 1980 and 1981, as far as I am concerned, is the deadline for completing the longer term solution.

Chairman HUMPHREY. I think that your warning to us, without trying to use any scare tactics, is something that we ought to take very, very seriously.

I wanted to ask a question in reference to the very important issue of decontrol. The FEA has talked of decontrolling retail gasoline prices. I guess you have ceilings, so to speak, on gasoline prices now.

Mr. ZARB. We have Federal price controls on gasoline prices.

Chairman HUMPHREY. What is the status of your agency's gasoline decontrol proposal?

Mr. ZARB. Well, as you know, Mr. Chairman, we have submitted to the Congress decontrol proposals on approximately one-half of the refined barrel, including middle distillates, residual fuel oil, lubes, and so on. The Congress has seen fit to approve those measures. Our experience to date has been that, when we remove those controls which are beyond the refinery and mostly affect small businessmen, we are not affecting the multinational corporation as compared to the small business. We have put an element of competition back into the system and we have seen some downward pressure on prices as a result of that renewed competition.

My staff is completing an economic analysis on gasoline. We have been somewhat delayed because of the lead phasedown ordered by the Environmental Protection Agency which changes the economic structure of that equation. I am hopeful that by the end of this month I will have that economic analysis completed.

In any case, such a proposal would have to go into the public domain. We would have to have public hearings that take from 6 to 8 weeks. It is not likely that the Congress is going to return after their October 2d recess until January.

I'm not hoping for an early return, Mr. Chairman, but when they do return, assuming that our economic analysis again indicates that removal of these controls will operate in favor of the consumer rather than against the consumer, we will submit it to Congress. But we have some weeks in which to pursue it.

The result of removing those controls that have been handcuffing the small businessman has been good. We have reduced the paperwork on those decontrolled commodities and they have been able to get out there and compete again in the good old American way and, as a result, the prices have been a lot more moderate.

Chairman HUMPHREY. So it has been a consumer advantage from your point of view?

Mr. ZARB. Yes, sir.

Chairman HUMPHREY. I have one last question—a rather ginger one. I read in the press recently after Mr. Kissinger visited Iran on a matter relating to barter arrangements, that the Iranian Government is pursuing or at least extending the letter of purchase for a number of F–16 planes—highly sophisticated planes. The article stated that while the Secretary of State was in Iran some discussion occurred regarding an oil-aircraft swap—the kind of barter involving Iran and such companies as General Dynamics, which manufactures the F–16, Ashland Oil, and New England Petroleum Co.

I'm interested in your observations on this, Mr. Zarb. I'm going to tell you that, as I looked at it, I thought the oil component of such a deal appeared to be somewhat of a smokescreen unless it means a reduced oil price for us. And I can't imagine Iran voluntarily reducing the price of oil. What concerns me about the Iranian arms deal more than anything else, is that the more arms they want to buy, more pressure is put on the Iranian Government to raise the price of oil to pay for the arms. It's my honest judgment that we will fuel our own inflation.

I'm going to hold hearings this week, by the way, on the whole subject of the arms deal. I'm chairman of the Foreign Relations Subcommittee on Foreign Assistance.

I would like to ask if you think there are any advantages in this kind of an oil-aircraft swap? What could we gain from an arrangement of this type, that the current situation doesn't provide? I'm speaking now from the matter of oil and security of oil production and delivery. Also, were you consulted on this?

Mr. ZARB. Yes, sir.

Chairman HUMPHREY. Prior to discussions with the Iranian Government?

Mr. ZARB. Yes, sir.

Chairman HUMPHREY. Things are picking up.

Mr. ZARB. Surprising, isn't it?

Mr. Chairman, I was in Iran earlier in the year and we talked about those pending discussions which were about to begin at that period.

Let me just describe the two areas of oil acquisition where this has been publicly discussed and to kind of sort them out. The U.S. Government in the next 6 years or so is going to purchase probably close to a half billion barrels of oil for storage.

Chairman HUMPHREY. For our reserve?

Mr. ZARB. Yes, sir. The President promised and the Congress agreed to a national strategic storage supply to protect us against a subsequent embargo, which I am very thankful for.

Now, there have been those who have tried to link other aspects of American trade to those particular negotiations to acquire that oil. My own view of the matter thus far is that, while overall trade relationships with any one partner will have an impact on the terms of another arrangement, that that particular transaction should stand on its own.

There should not be too much complicating the issue or the issue should be that the Government has responsibility to acquire the oil at the best possible price for the American taxpayer and to keep it clean and straight in that regard, so that at least until now we have not considered the barter characteristics with respect to oil for that reserve. That may change if some new condition arises but three or four discussions have taken place between the Government of Iran and the three or four manufacturers of arms in this country. I was apprised of the fact that these discussions were about to take place when I was in Iran and the general conditions associated with them. I've since been briefed on subsequent discussions that have taken place between the companies and the Government of Iran. My original perception that such transactions might be mighty, mighty difficult to pull off has proven to be correct. You not only need a willing arms manufacturer, you need a willing American oil company that is willing to enter into a long-term arrangement for that quality of oil coming from that part of the world. You need to agree on price in the face of Iran being a member of the OPEC community. They are certainly not going to do anything on the face that appears to be violating the code of conduct of its fraternity brothers.

It was my anticipation that such a transaction would be most difficult to pull off; it still is. To the best of my knowledge, those discussions have not gone forward in any bold manner that would indicate an announcement forthcoming within the next several weeks. We'll continue to be informed of progress and my perception may change as time goes on but at the moment, since the U.S. Government is consulted on all these matters, it would be my view to look at each transaction with a very sharp eye.

Chairman HUMPHREY. As I understand it, the OPEC countries, particularly Iran and Saudi Arabia, have arrived at a certain volume of production in order to conserve their own fuel. The Saudis have been a little more generous in this area than the Iranians because the Iranians have a smaller reserve of oil.

My perception of what has taken place thus far is very much like yours in your initial statement; namely, if such a barter would take place, it would occur outside the normal commercial channel and it would have to be over and beyond the current level of production. The Shah, in other words, would have to expand production for the purpose of putting that oil into our reserves.

Mr. ZARB. Going back to the first part, it is even further constrained than that. The Iranians have had fairly good success in marketing their light crude which is the preferred crude and the excess capacity, both in Iran and Venezuela, has been the very heavy crudes. You can't import all heavy crude and expect to make all the products you need from that crude in the time of national emergency. So the likelihood of that kind of transaction being associated with a barter arrangement or a strategic reserve at the moment is almost zero, until I see something that will change my position.

Chairman HUMPHREY. Thank you very much, Mr. Zarb. Again, we appreciate your willingness to be of service to the committee. Your prepared statement together with the report entitled "Petroleum Supply Alternatives for the Northern Tier States Through 1977" will be placed in the hearing record.

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[The prepared statement of Mr. Zarb, together with the report referred to follow:]

PREPARED STATEMENT OF HON. FRANK G. ZARB

Mr. Chairman and members of the committee, thank you for the opportunity to appear today and discuss the energy outlook over the next several years for the northern tier states. I intend to cover a wide range of topics which I know are of interest to the committee. These include the oil and gas situation for this winter; our evaluation of the northern tier situation both short-term and long-term; and the current status of Canadian/U.S. crude oil exchanges.

The northern tier depends on natural gas for 27 percent of its energy requirements with petroleum providing 39 percent, coal providing 17 percent, hydro 15 percent, and nuclear 2 percent. Any action affecting the availability of natural gas impacts on the demand for petroleum. This country's natural gas supplies have been declining in recent years and oil exports from Canada are being reduced. These two factors will obviously adversely affect the northern tier and provide some immediate cause for concern. However, we believe that there is still time for industry to implement new energy supply alternatives before the supply of gas and oil to the northern tier is severely disrupted.

In viewing the energy situation for the northern tier, it is important to remember that in spite of the recent declines natural gas remains a vital source of domestic energy.

Although contracts to export gas from Canada are not being renewed, the Canadian Government has assured us of no new curtailments of existing contracts for natural gas in the 1976–77 heating season. In fact, there is only a small probability of additional curtailments of natural gas on the trans-Canada pipeline system through 1980. Both FEA and the Federal Power Commission are in the process of reviewing data gathered in a survey of the pipeline companies which supply natural gas to the northern tier states. Preliminary data indicate that with normal winter weather, curtailments will be about the same as last winter. In fact, deliveries are expected to be higher in each of the states except Washington where deliveries are currently projected to be only 2 percent below last winter.

Alaskan natural gas reserves may provide some future relief to our dwindling domestic supplies. Alaska contains one of the largest known U.S. areas of undeveloped natural gas. In addition to currently proven reserves, there are an estimated 76 trillion cubic feet of undiscovered recoverable gas resources.

There are presently three proposals for the transportation of Alaskan gas now before the Federal Power Commission. The trans-Alaska or El Paso proposal, the trans-Canada or Arctic gas proposal, and the Alcan Highway or Northwest pipeline proposal.

The length of time involved in selecting and certifying one of the systems and in receiving all the required Federal, State, and local permits that will permit construction to begin will have an impact on the northern tier's energy supply picture.

FPC presently is holding a combined hearing on these proposals which I believe is to be completed by November 1. An administrative law judge decision will probably be made before the end of December, and the final FPC review is scheduled for completion by March 1, 1977. Gas should begin flowing within 3 to 5 years after FPC approval depending on the system chosen.

In the interest of insuring a timely decision on this issue and coordinated governmental decision making, the administration has submitted to Congress a bill that would do the following: (1) direct the Federal Power Commission to complete its review of proposed transportation systems and transmit a determination to the President by January 1, 1977, (2) allow the President to make a decision after he receives the agencies' assessments no later than August 1, 1977.

Recent experience with the development and construction of major energy related projects has continuously demonstrated that the longer delay the more expensive these projects become.

It is obvious that these additional supplies of natural gas will not be available in the northern tier until the early 1980's and that crude oil and petroleum products will be a major component of the energy supply equation now and in the future.

Last October John Hill, my deputy, addressed this committee on the energy problems confronting the northern tier States (Washington, Montana, North

Dakota, Minnesota, Michigan, and Wisconsin) and particularly the State of Minnesota. We stated then that FEA was completing plans for an allocation system that would provide a first level of protection to landlocked northern tier refiners.

On April 1, 1976, the Federal Energy Administration implemented the mandatory Canadian crude oil allocation program. Allocations to northern tier refiners are based upon an evaluation of their demonstrable reliance on Canadian crude and on their access to alternative crude oil distribution systems. Two 6-month allocation periods have distributed the reduced Canadian crude exports equitably among the refiners who rely on Canadian crude oil. In addition, the FEA is continuing to meet with the National Energy Board of Canada to examine the means of alleviating the effects of the anticipated decline in Canadian crude oil exports available for the northern tier refiners.

With regard to this winter's energy supply, it is anticipated that due to increased demand and curtailed crude oil supplies from Canada, it is expected that this winter there will be a 29-percent increase from the 1975–76 product inshipments to the northern tier States. However, if a severe winter occurs, additional product could be needed. Spare product pipeline capacity is sufficient from other areas into the northern tier States to accommodate these increases. Midwest refineries currently supplying these areas have the capacity to handle this increase. It is not anticipated that there will be any significant petroleum product shortages in the northern tier States.

Although there was some concern last year about propane, for this coming winter it appears that there will be adequate supplies of propane. The National Energy Board of Canada projects 28,525,000 barrels of propane will be approved for export to the United States from April 1976 through March 1977. Virtually all this propane is used in the northern tier States. Recently there has been a temporary and limited surplus of Canadian propane and, as a result, the United States has been asked to increase its imports. It is expected that we will begin the 1976–77 heating season with substantial propane inventories which, together with domestic production and imports, are expected to be more than adequate to meet traditional requirements throughout the United States and specifically to the northern tier.

On August 2, the Federal Energy Administration submitted a report to Congress on "Crude Oil Supply Alternatives for the Northern Tier States." The purpose of this study was to assess the feasibility, cost and environmental aspects of alternative petroleum sources and transportation systems for the northern tier States and to recommend steps Federal and State Governments and private industry can take to assure uninterrupted oil delivery to this region. The study was prepared by FEA in close cooperation with representatives of the six concerned States and with the the Departments of Interior and Transportation, EPA, and the National Oceanographic and Atmospheric Administration.

The report outlines long-term supply alternatives to the northern tier, basically for the post 1979 time frame. This report was supported by volumes I and II of a study conducted under a contract awarded to Bonner and Moore Associates, Inc., consulting engineers. My staff extracted information from these studies and conducted additional analyses to identify the areas which could be impacted by the various proposals. Because of the broad range of options under consideration, it was not possible to determine the full impact in each area. The study represents a tremendous amount of valuable information which we are able to use as a basis for further analyses.

FEA is presently preparing a second report for submission to Congress which will analyze the potential supply gap that could exist between 1977 and the implementation of long-term solutions, sometime after 1979 and which will show what supply options may be available. The second report will be based in part upon volume III of the Bonner and Moore study. Because this volume deals with the actual short-term plans of various companies, it is less speculative than the long-term study. Our knowledge about the northern tier situation has expanded considerably by the information contained in this study.

I would like to briefly discuss what FEA has identified with regard to potential long-range solutions for the northern tier.

Our assessment considered 12 different long-term supply alternatives. The following five proposals have been found to be economically feasible:

1. Trans-provincial proposal, which includes a deepwater port and terminal in British Columbia and a pipeline to connect with the inter-provincial pipeline.

(2) Northern tier pipeline, which includes a deepwater port at Port Angeles, Washington, and a pipeline across the northern tier States.

(3) The Sohio-plus alternative which includes, (1) a terminal in Long Beach, California, and a pipeline to Midland Texas, (2) The Wiliams pipeline expansion from Tulsa to Minneapolis, and (3) a new pipeline to supply Montana and North Dakota.

(4) The loop alternative, which includes a deepwater offshore port off Louisiana and would provide crude oil through the capline system to the Great Lakes region.

(5) The Seadock proposal, which would provide crude oil from the Houston area to Tulsa and Chicago areas.

The last two proposals, loop and seadock, appear economically feasible, independent of northern tier needs. However, they would not supply crude oil directly to the northern tier refiners.

The relatively lengthy time required for completion of each of these long-term solution options means they are inadequate to relieve the short-term impacts resulting from the Canadian export reduction.

The implementtaion of any long-term solution to the northern tier States crude oil supply problem probably will not be operational until at least late 1979. As I have previously indicated we are continuing to analyze the problems to be encountered between now and the implementation of a permanent long-term solution.

The fact that there are four distinct supply and marketing areas in the northern tier States makes it impossible to analyze them as a single entity. The six-State northern tier area is logically divided by supply routes in four distinct supply and marketing areas. These areas are:

(1) Southern Michigan;

(2) Minnesota, Wisconsin, northern Michigan, and eastern northern Dakota;

(3) Montana, western North Dakota, and eastern Washington;

(4) Western Washington.

Before discussing some of the specifics that have been identified for the short term, I would like to point out that economic uncertainties are currently inhibiting investment in possible refining and pipeline alternatives. Among these uncertainties are possible governmental actions concerning divestiture, price controls, and the question as to when a long-term alternative such as the northern tier or trans-provincial pipeline will be in place.

FEA's preliminary analyses indicate that the market areas of southern Michigan and western Washington should have sufficient petroleum supply to meet demand. The marketing area including Minnesota and Wisconsin should make it to 1980 without significant petroleum shortages, primarily because of the Williams Brothers pipeline expansion. In the market area including Montana, we are somewhat concerned about the unavailability of additional indigenous acceptable crude oil and lack of spare product pipeline capacity. However, we believe that it will be two or three years before problems might develop. Anticipating a possible shortfall this far in advance enables industry to take actions to develop alternate supplies. Thus, it is probable that any shortfall can be averted.

The proposed expansion of the Williams Brothers pipeline system would have a significant affect on crude oil availability in the northern tier. It will make possible the reallocation of approximately 55 MB/CD in 1978 to other northern tier areas, such as Montana and Wisconsin. If this pipeline is not utilized or is not expanded to at least 135 MB/CD, then shortages of petroleum supplies could result by early 1979.

We will submit more precise information to Congress after our short-term analysis is completed. It should be completed by October.

Crude oil exchanges with Canada are perhaps the most promising means of alleviating the short-term petroleum supply shortage in the northern tier. Last year the two countries agreed that commercial exchanges between Canadian and U.S. companies if consistent with broad energy policy guidelines, should not be precluded by present legal, administrative or fiscal regulations in either country.

Last October we told this committee we were analyzing the possibilities for the exchange of oil between Canadian and U.S. refiners within the framework of existing policies affecting them and that we had agreed with the Canadian Government that the respective governments would not be parties to exchanges, but would maintain a favorable environment within which exchanges could take place.

As of September 1, 1976, FEA has processed seven exchange requests. To facilitate six of these exchanges, FEA has issued import licenses for a total of 47 MBD. FEA has recommended that the Department of Commerce issue corresponding export licenses. We understand that three export licenses totalling 10 MBD have been issued.

Although the Government of Canada has stated that oil swaps will continue to be in addition to the Canadian exportable surplus, this is not an indication that swaps can be used indefinitely in lieu of building a transportation system to provide crude oil to these refiners.

Since 1973 the Canadian oil curtailment has resulted in a drop in oil imports to the U.S. of about 700 MBD. Meeting this gap has caused a sizeable increase in domestic pipeline utilization from the Gulf Coast to replenish the lost Canadian crude oil. In spite of increases in capacity, many of the U.S. pipeline systems are pushing maximum capacity and in some instances have had to prorate. For example, the Texoma pipeline which carries crude oil from the Gulf of Mexico to Cushing, Oklahoma, had spare capacity in June, and in August was prorating at 69 percent. There simply is not sufficient unused capacity from the Gulf of Mexico to meet all of the potential exchanges using only the Lakehead/Inter-Provincial pipeline route.

The Federal Government is seeking ways to expand the parameters for exchanges with Canada. At a meeting scheduled for early October, we will again pursue the possibility of using offshore rather than U.S. domestic crude for exchanges.

The Canadian Government is likely to seek assurance of a long-term solution to the problem of supply for the northern tier refiners. We plan to demonstrate that we have made a real effort to use domestic oil, and to outline the constraints posed by our current pipeline system.

I appreciate the important role which the individual states play in energy questions. No important energy problem can or should be solved without the direct involvement of state representatives. The northern tier situation requires that FEA and other Federal agencies work continuously with state and local officials to develop the framework within which critical State and national objectives can be addressed.

The Federal Energy Administration is encouraged by the various private industry proposals for transportation systems to provide alternate petroleum supplies to the northern tier area. In light of the serious supply problem which is expected to occur in the northern tier States, FEA feels that it is imperative that prompt action be taken by the participants to resolve the problem.

Whether or not the short-term problem is substantial and governmental involvement is necessary or appropriate cannot be determined until the short-term report is completed.

A long-term solution for providing a supply of petroleum to the northern tier States appears to be possible. Industry has indicated a willingness to commit capital to the various alternatives now being considered. Consequently, the FEA does not see a need at this time for governmental role to effect long-term solution except to encourage prompt action by Federal, State and local officials responsible for permitting activities.

PETROLEUM SUPPLY ALTERNATIVES
FOR THE NORTHERN TIER STATES
THROUGH 1977

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Volume III
Short-Term Report

4 August 1976

Prepared for the
Federal Energy Administration
under Contract No. CR-05-60593-00

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# SECTION 1

# INTRODUCTION

This document, Volume III in the study of Northern Tier alternatives for energy supplies, contains the results from performance of Tasks 4 through 7 assigned as additions to the Federal Energy Administration's Contract No. CR-05-60593 under a modification dated June 19, 1976.

## 1.1 PURPOSE AND SCOPE

The principal purpose of the work covered by this document was to gather detailed information related to refineries, pipelines, domestic crude supply, and other forms of petroleum transport that will aid the U.S. Federal Energy Administration-Office of Regulatory Programs in its tasks of allocating dwindling supplies of Canadian crude oil. Where possible, impediments to securing alternate supplies of crude oil through 1977 are identified and highlighted.

Specific task descriptions were condensed into the following list, which is illustrative of the intent and scope of Bonner & Moore's work under the contract extension.

- *Analysis of each facility in the Northern Tier States which currently uses Canadian crude oil in order to assess its ability to use other raw material.* Northern Tier States, as defined by the work statement of the study, include Michigan, Wisconsin, Minnesota, North Dakota, Montana, and Washington. Facilities analyzed include refineries, power plants, and one SNG manufacturing facility. Affidavits to the FEA, visits to all Priority 1 facilities, and telephone interviews with representatives of Priority 2 facilities yielded the data necessary for drawing study conclusions. Planned changes to facilities through 1977 and obstacles to alternate raw stock usage were documented and included process units, dockage, storage, local pipeline, and truck/rail unloading facilities.

- *Analysis of the operation of crude and product pipelines which service the Northern Tier States and are capable of transporting non-Canadian crude oil.* Principally, these data include capacities, committed throughput, and planned expansions through 1977. Unit train and barge transport were considered as alternate modes of supplying crude oil.

- *Description of domestic crude oil supplies in Montana, North Dakota, Michigan, and Wyoming in terms of production quantities, quality, location, and producers.*

- *Calculation of the effect of alternate supplies on product prices in the Northern Tier States through 1977.* Calculations are based on replacing lost Canadian crude by the most reasonable product or crude supply route.

The scope of our tasks was limited to the six Northern Tier States and consideration of only those facilities changes which could be in place by the end of 1977. It was recognized that certain of the required data would be considered proprietary by pipeline, refining, and producing companies and would not be released to Bonner & Moore. When this occurred, estimates of data were made when technically feasible.

## 1.2 DOCUMENT ORGANIZATION

The balance of this report document is organized as follows:

- Section 2 contains major conclusions drawn from the study's analyses.
- Section 3 presents orientation information and some analytical results on refining facilities, transportation facilities, and crude oil production in the Northern Tier and Wyoming.
- Section 4 presents analytical results from the study--including the required analysis of added costs for products in the Northern Tier States during the next 18 months.

Three separately-bound addenda support this report:

- Addendum A details each Priority 1 and 2 facility in the Northern Tier (PROPRIETARY).
- Addendum B describes each crude and product pipeline that is involved in supplying the Northern Tier (PROPRIETARY).
- Addendum C contains production data for Michigan, Montana, North Dakota, and Wyoming.

## SECTION 2

## MAJOR CONCLUSIONS

This section summarizes five major conclusions drawn from the short-term Northern Tier supply study and briefly presents the bases for these conclusions.

- *The Northern Tier cannot be viewed as a single entity for purposes of analysis or regulation.*

  The six-state Northern Tier area is logically divided by supply routes into four distinct supply and marketing areas. These areas are:

  (1) Southern Michigan

  (2) Minnesota, Wisconsin, Northern Michigan, and Eastern North Dakota

  (3) Montana, Western North Dakota, and Eastern Washington

  (4) Western Washington

- *Each area of the Northern Tier will be able to meet projected petroleum demands through 1977 by utilizing existing transportation and refining systems.*

  The situation of the four Northern Tier areas through 1977 is as follows.

  (1) *Southern Michigan* - This area has surplus product pipeline capacity through 1977. Crude pipeline capacity is tight through

1977. Surplus crude capacity exists from Chicago, but is bottlenecked into Chicago from the Gulf Coast without the Explorer expansion. Expansion of the Explorer line requires 0.25-1.0 MM$ investment and about three months' lead time.

(2) *Minnesota, Wisconsin, Northern Michigan, and Eastern North Dakota* - Existing spare capacity for crude oil and products pipelines is insufficient to meet demands in this area when Canadian crude imports decline to levels projected for 1977. Although this area draws products from common sources, crude oil supply to this area actually constitutes two separate problems--one for refineries in Minneapolis-St. Paul and another for refineries in Superior, Wrenshall, and Mandan. Crude oil can, for example, be made available for Minneapolis-St. Paul refineries through the projected expansion of the Williams pipeline in late 1977. Alternatively, barges are a potential short-term solution for Minneapolis-St. Paul refiners, although this would involve addition of tankage. The Williams expansion, however, would be of only limited help to Superior and Wrenshall refineries--and of no help at all in Mandan. Barges would also be of no help for any of these three refineries. The only solution to short-term crude supply problems in Superior, Wrenshall, and Mandan (other than exchanges) appears to be a very expensive one--the use of unit trains.

(3) *Montana, Western North Dakota, and Eastern Washington* - This area has no spare product pipeline capacity, except for possible supplemental supply to eastern Washington only from Utah (which appears unlikely because of restricted refinery capacity in Salt Lake City) or by getting product to Denver (which indirectly satisfies Montana refineries' markets). Crude pipeline capacity is also tight in 1977, but reversal of the Glacier line could produce 9 (with potential upgrade to 25) additional MB/CD. Eastern Washington could be supplied by barges on the Columbia River from the western Washington refineries (if the pipeline from Pasco has capacity), and Montana could be supplied by unit trains; both these possible alternatives require investment and lead time.

(4) *Western Washington* - Because the Washington refiners can receive crude over their docks and currently produce 50 percent more product than their market area (western Washington and western Oregon) requires, this area has no problem in the short term.

- *Without additional investments in transportation systems and refinery facilities, the years past 1977 will be very difficult for most of the Northern Tier.*

With continued growth in demand, decreased amounts of Canadian crude, and allocation of crude by crude type, by the end of 1977 the Northern Tier will have exhausted its existing pipeline capacity to supply both crude and product. A long-term supply alternative will not yet be in place, and short-term investment is unlikely.

- *Of the petroleum product price increases between 1976 and 1977, only about 0.2 to 0.3 cents per gallon can be attributed to replacing Canadian crude oil.*

  This conclusion is supported in detail in Section 4 of this report.

- *Exchanges are perhaps the most promising means of alleviating the petroleum supply shortfall in the Northern Tier.*

  Three types of exchanges (currently restricted by government regulations) could benefit the Northern Tier refiner and better enable him to service his product area:

  (1) *Exchanges among U. S. and Canadian refiners* - The present Canadian restriction requiring U.S. domestic oil in exchange for Canadian oil seriously limits this solution due to pipeline limitations in the Chicago area. The best solution is the exchange of foreign oil through Montreal, and every effort should be made to accomplish this exchange. Volumes I and II of this study contains further details on this alternative.

(2) *Exchanges of Canadian allocations among U.S. refiners* - This is currently only possible within a company. It would be beneficial for U.S. refiners with Canadian allocations that they cannot run to exchange crude (perhaps Canadian; perhaps domestic) with other U.S. refiners.

(3) *Other exchanges among U.S. refiners* - Exchanges among refiners with access to different processing capabilities could be an attractive short-term alternative as described in subsection 3.1, provided that the supplier/purchaser relationships of 10 CFR 211.63 of the Allocation Regulations can be satisfied and recognizing the existing price ceilings.

The foregoing conclusions were based on the best data available to Bonner & Moore in the time frame of this study. It must be recognized that data supplied by individual pipeline companies and refiners could possibly be somewhat biased toward the interests of the contributors. Also some involved companies refused to supply Bonner & Moore with data not in the affidavits filed with FEA.

The above conclusions were also based on anticipated "average" conditions. A harsh winter or excessive tourism could, of course, increase demand for petroleum products beyond that projected. Such seasonal impacts were beyond the scope of this study.

It must be recognized that economic uncertainties are currently inhibiting investment in possible refining and pipeline alternatives. Among these are governmental actions concerning divestiture, cost pass-through, and lead phase-down, and the uncertainty that a long-term alternative such as a Northern Tier or Trans-Provincial pipeline will be in place by 1980.

# SECTION 3

# ORIENTATION

This section describes the basic functions and processes of the 25 Northern Tier Priority 1 and 2 plants, and describes the transportation networks that link these plants with their supply sources and their markets. This section is intended to educate the reader in the operation of refineries and the refining and transportation problems that are unique to the Northern Tier.

Subsection 3.1 describes the basic functions and processes of refineries, power plants, and SNG plants as they pertain to such facilities in the Northern Tier. Emphasis is on refineries which constitute 21 of the 25 facilities and represent 782 MB/CD of the 844 MB/CD throughput for the first half of 1976.

Subsection 3.2 details the existing petroleum transportation network--with emphasis on pipelines--including possible expansions and potential new means of crude supply such as unit trains and barges.

## 3.1 PLANT ORIENTATION

The Priority 1 and Priority 2 plants in the Northern Tier consist of 21 refineries, three power plants, and one synthetic natural gas (SNG) plant. The following paragraphs describe the basic functions and processes involved in such plants.

### 3.1.1 Refineries

In general, a typical Northern Tier refinery is constrained--by existing facilities--in its ability to process heavy, high-sulfur crude. Most of these refineries were designed to process local light, sweet crude into gasoline, heating oil, and a limited amount of asphalt. Therefore, the typical Northern Tier refiner does not have facilities to receive non-Canadian foreign or Alaskan North Slope crude, to distribute the heavier product slate, or to adjust the intrinsic qualities of the crude to meet various product specifications.

In order to explain the processing problems of Northern Tier refiners, the intricacies of refinery operation are described here in terms of:

1) A description of the units and operation of a hypothetical "basic" (non-Northern Tier) refinery processing 50 MB/CD of light, low-sulfur Canadian crude (paragraph 3.1.1.1).

2) A discussion of the impact on the hypothetical basic refinery of changing to run a mixture of 25 MB/CD of light, medium-sulfur Arabian crude and 25 MB/CD of heavy, high-sulfur Arabian crude (paragraph 3.1.1.2).

3) A description of a "typical Northern Tier" refinery processing 50 MB/CD of light, low-sulfur Canadian crude (paragraph 3.1.1.3).

4) A discussion of the impact on the typical Northern Tier refinery of changing to run a mixture of 25 MB/CD of light, medium-sulfur Arabian crude and 25 MB/CD of heavy, high-sulfur Arabian crude (paragraph 3.1.1.4).

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5) A discussion of some of the variations in the Northern Tier refinery's processing capacity (paragraph 3.1.1.5).

### 3.1.1.1 "Basic" Refinery

A basic refinery processing light Canadian crude is presented in Figure 3-1. The general facilities and processing flow sequence is as follows.

The crude is transported via pipeline, received into tankage, and stored until needed. This refinery generally has minimal tankage since crude is available on an as-needed basis.

The first processing unit in the overall flow is called an atmospheric pipestill because it operates at near atmospheric pressure. (It is also called the crude unit.) This unit splits the 50 MB/CD of crude into various boiling ranges from light to heavy products. The lighter streams physically come off the top of the unit, heavier streams are removed from the sides, and the heaviest stream is removed from the bottom.

The light stream, a vapor at atmospheric conditions, is sent to a gas recovery unit--where it is split into 400 fuel oil equivalent barrels (FOEB) per calendar day of fuel gas, which is typically consumed within the refinery, and 0.2 MB/CD of butane, which is used to blend gasoline.

Moving from the top to the bottom of the atmospheric pipestill, the next series of hydrocarbons to come off are considered straight-run gasoline. These streams, totalling 13.5 MB/CD, are blended with 1.6 MB/CD of butanes to make the regular-grade gasoline purchased at the gas station. This basic refinery must import 1.4 MB/CD of butanes to blend such gasoline.

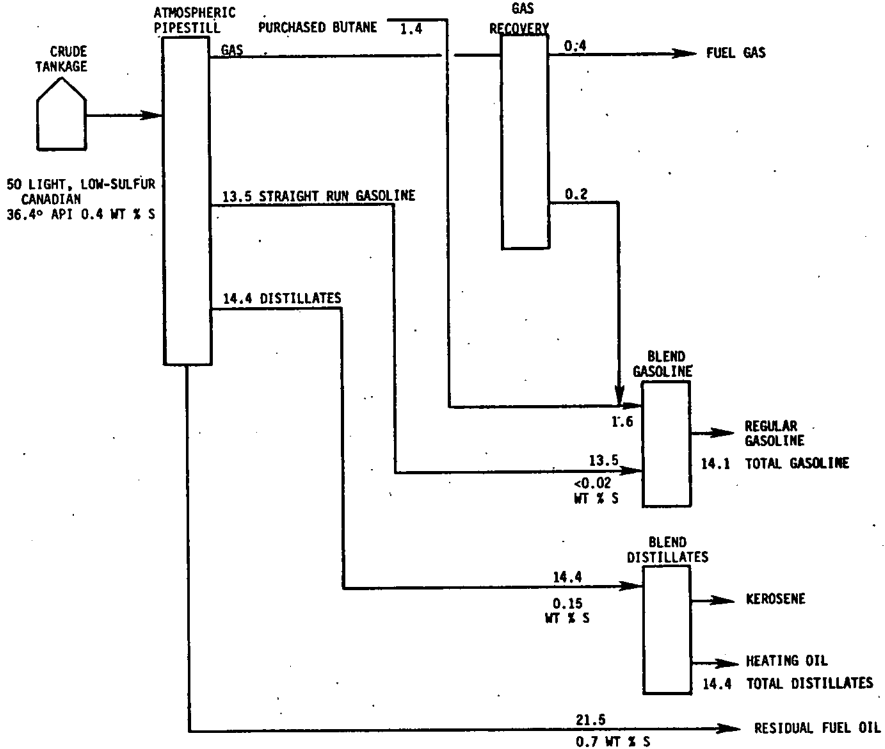


Figure 3-1. Basic Refinery Simplified Flow Diagram, Light Canadian Crude (MB/CD)

The next heavier boiling range materials are called distillates. These distillates, totaling 14.4 MB/CD, are used to blend kerosine and heating oil. The 21.5 MB/CD stream to come off the very bottom of the atmospheric pipestill is called "reduced crude" or "topped crude," which this basic refinery uses for residual fuel.

For the purposes of this Northern Tier study, the important things to consider about this basic refinery are: (1) it contains very limited crude tankage; (2) the product tankage is sized to handle the expected product rates, and markets have been developed for these typical rates; (3) the product quality must exist in the crude as it is received, since there is really no ability to alter the intrinsic properties of the crude (the products are simply physically separated in the atmospheric pipestill); and (4) the pipestill and gas-recovery units contain metals that are designed for the low corrosion rate that is typical of light, low-sulfur Canadian crudes.

#### 3.1.1.2 Changing the Basic Refinery's Crude Mix

Figure 3-2 presents the same refinery but now feeding a mixture of 25 MB/CD of light, medium-sulfur Arabian crude and 25 MB/CD of heavy, high-sulfur Arabian crude. This mixture is heavier than the light Canadian, 30.5° API versus 36.4° API, and was higher in sulfur, 2.4 weight percent sulfur versus 0.4 weight percent sulfur.

In order to run this mixture of foreign crude, the refinery must first be able to receive it by pipeline, and must have considerably more crude tankage to be able to: (1) receive the light crude and the heavy crude separately; (2) blend the 50/50 mixture in order to process it; (3) minimize transportation cost by receiving larger batches; and

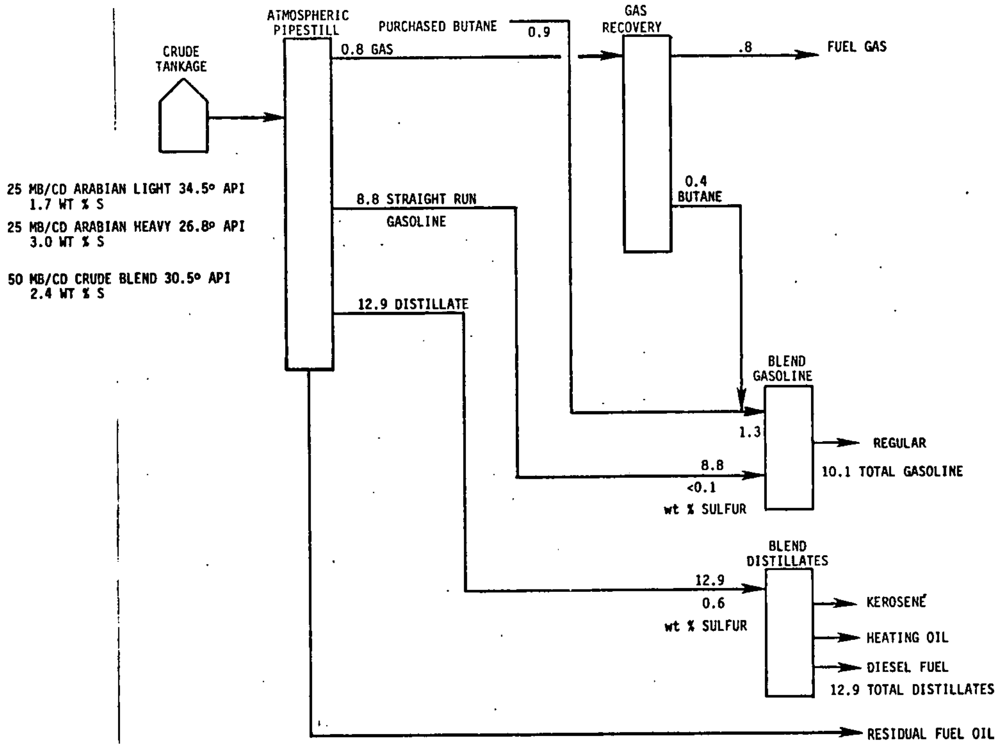


Figure 3-2. Basic Refinery Simplified Flow Diagram, Light and Heavy Arabian (MB/CD)

(4) provide for the variability of crude availability. In this case the Northern Tier refiner would not have enough gasoline or distillates to meet his typical sales volume, and he would have 26 percent more residual fuel with five times the sulfur level (3.7 versus 0.7 weight percent sulfur) to market in an area that has very little demand for high-sulfur residual fuel. Also, this basic refiner would have to maintain (take out of service for "overhaul") the atmospheric pipestill in order to upgrade materials of construction to handle the higher corrosion rate resulting from these crudes.

Comparing Figures 3-1 and 3-2 shows that the straight-run gasoline yields are 5.0 MB/CD (33 percent) lower, the distillate yields are 1.5 MB/CD (10 percent) lower, and the residual fuel yields are 5.6 MB/CD (26 percent) higher. It is doubtful that this basic refinery would actually be able to process this particular crude slate at rated capacity because the atmospheric pipestill was not designed to handle this high-reduced-crude rate.

In the short term, this basic refinery must: (1) develop a market for the 5.6 MB/CD of high-sulfur residual fuel; (2) run at reduced throughput (less than capacity) due to the limited residual fuel tankage; and (3) tank car the residual fuel significant distances to places where it can be burned or blended with other low-sulfur fuel stocks to make an acceptable residual fuel. This would probably not be economically attractive.

The other short-term alternative would be to obtain crudes that are somewhat similar to low-sulfur Canadian crudes, that have the intrinsic product qualities needed, and that produce roughly the same product distribution as the lighter Canadian crudes. These crudes are, of course, in high demand and are cumbersome to transport from their source to the refinery.

In the long term, this basic refiner could expand his facilities to upgrade the residual fuel to distillates and gasoline in order to produce on-specification products. This would require a significant investment and a two to four-year lead time--at a time of unsure crude supply and an uncertain refining future.

3.1.1.3 Typical Northern Tier Refiner

Figure 3-3 shows the facilities and flow sequence of a typical Northern Tier refinery; the additional facilities over those of the basic refinery are highlighted.

A pair of units (called a reformer feed hydrofiner and a catalytic reformer) have been added to the heavier gasoline stream on the atmospheric pipestill. The reformer feed hydrofiner lowers the sulfur-level of feed to the catalytic reformer from 400 parts per million (ppm) to less than 50 ppm. Sulfur-level must be below 50 ppm for the reformer catalyst to function properly. The catalytic reformer converts 11.0 MB/CD of virgin, low-octane naphtha into 8.8 MB/CD of higher octane reformate at a yield loss by producing 1.6 MFOEB/CD of gas. This unit enables the refiner to produce premium gasoline.

A vacuum pipestill has been added to split the 18.8 MB/CD of reduced crude from the atmospheric pipestill into 13.0 MB/CD of catalytic cracker feed and 5.8 MB/CD of bottoms. The 5.8 MB/CD of bottoms of this vacuum pipestill can be sold as residual fuel if it is blended with some catalytic cracking heating oil or can be sold as asphalt if if meets the various asphalt specifications.

The catalytic cracker processes 2.7 MB/CD of light gas oil from the atmospheric pipestill and 13.0 MB/CD of heavy gas oil stream from the vacuum pipestill. The primary products

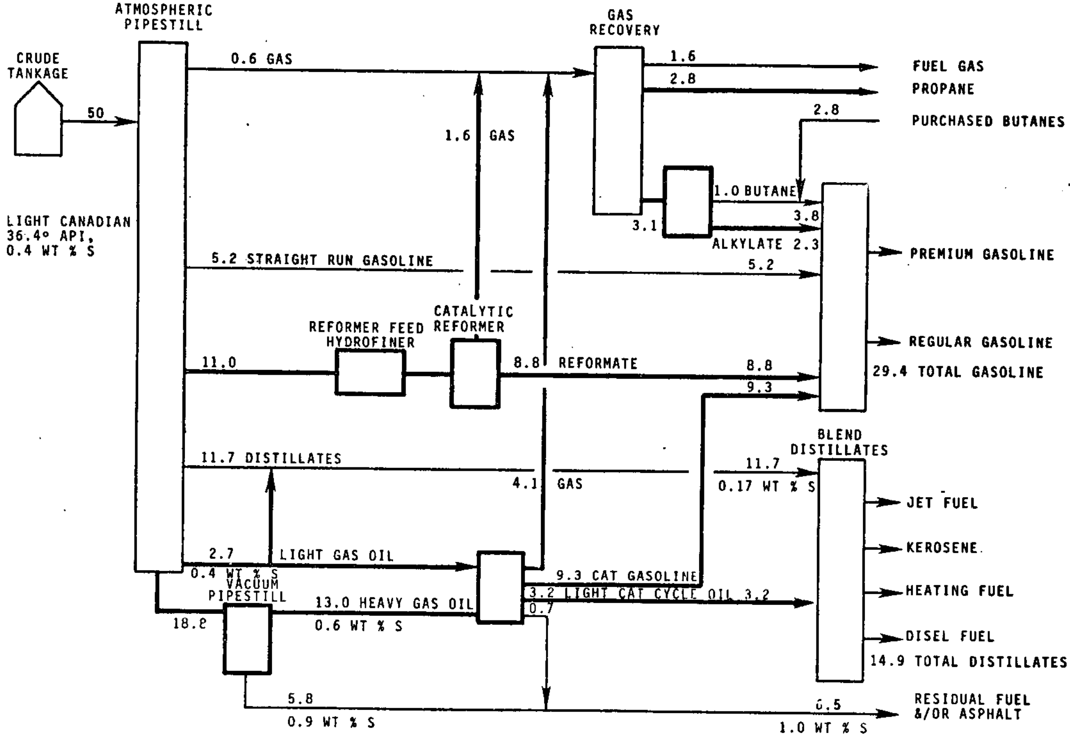


Figure 3-3. Typical Northern Tier Refiner Flow Diagram, Processing Light Canadian Crude (MB/CD)

from the "cat cracker" are 9.3 MB/CD of catalytic gasoline and 3.9 MB/CD of catalytic heating oil. The cat cracker produces a significant amount of gas recoverable in gas recovery. This cat cracking gas contains olefins, so a new process, called alkylation, is added to the gas recovery section. Alkylation combines these olefins with various butanes and produces 2.3 MB/CD of high-quality alkylate.

This typical refinery can produce reasonable volumes of premium gasoline because of the additional alkylation and reforming processes. Since the atmospheric pipestill has additional fractionation capability, this refinery can also product jet fuels. The gas recovery section is designed to recover 2.8 MB/CD of propane for sale as LPG or for use as fuel gas.

The most significant consideration of this typical Northern Tier refinery is that it produces 95 percent more motor gasoline (29.4 versus 15.1 MB/CD) than is produced in the typical basic refinery and about the same volume of distillates. The increase in motor gasoline production is at the expense of producing residual fuel. That is, the 21.5 MB/CD of residual fuel that is intrinsic in the crude has been converted into 13.9 MB/CD of gasoline, 6.5 MB/CD of heavier residual fuel, and some fuel gas.

Another significant point about the typical Northern Tier refinery is that it has some flexibility to change the relative volumes of motor gasoline, heating oil, and residual fuel oil produced. The refinery could shut down the cat cracker and alkylation units and produce the same products slate as the basic refiner, but more typically the refinery will move the 2.7 MB/CD light gas oil stream that goes to the cat cracker and put it directly into distillates. The result would be a decrease of about 1.6 MB/CD of gasoline and an increase of about 2.3 MB/CD of distillates.

It should be apparent at this point that: (1) crude contains a mixture of gasoline, heating oil, and residual fuel oil; (2) a refinery *separates* these various hydrocarbons into saleable products; and (3) processes can be added to the refinery to *convert* the residual fuel oil into gasoline and heating oil and to upgrade the quality of that gasoline into premium gasoline. This ability to move or change the ratio of gasoline and heating oil is necessary in order to meet the seasonal demands of gasoline and heating oil.

The only other two options that a typical refinery has is to add significant additional tankage to store the gasoline produced in the winter time for sale in the summer time, and then to use that same tankage to store the heating oil produced in the summer time for sale the following winter. Obviously the refinery could also increase the crude run in one period or another to increase the volume of products, but in general this is not economically attractive because it would require signficant investment for spare capacity that would be used infrequently.

#### 3.1.1.4 Changing the Typical Northern Tier Refinery's Crude Mix

Recognizing that the typical Northern Tier refinery does not have the capability of changing facilities in the short term, the same plant that is shown in Figure 3-3 is depicted in Figure 3-4 processing 25 MB/CD of Arabian light and 25 MB/CD of Arabian heavy crudes. This is strictly a hypothetical picture, since it is doubtful that any of the typical Northern Tier refineries would be able to process this particular crude slate.

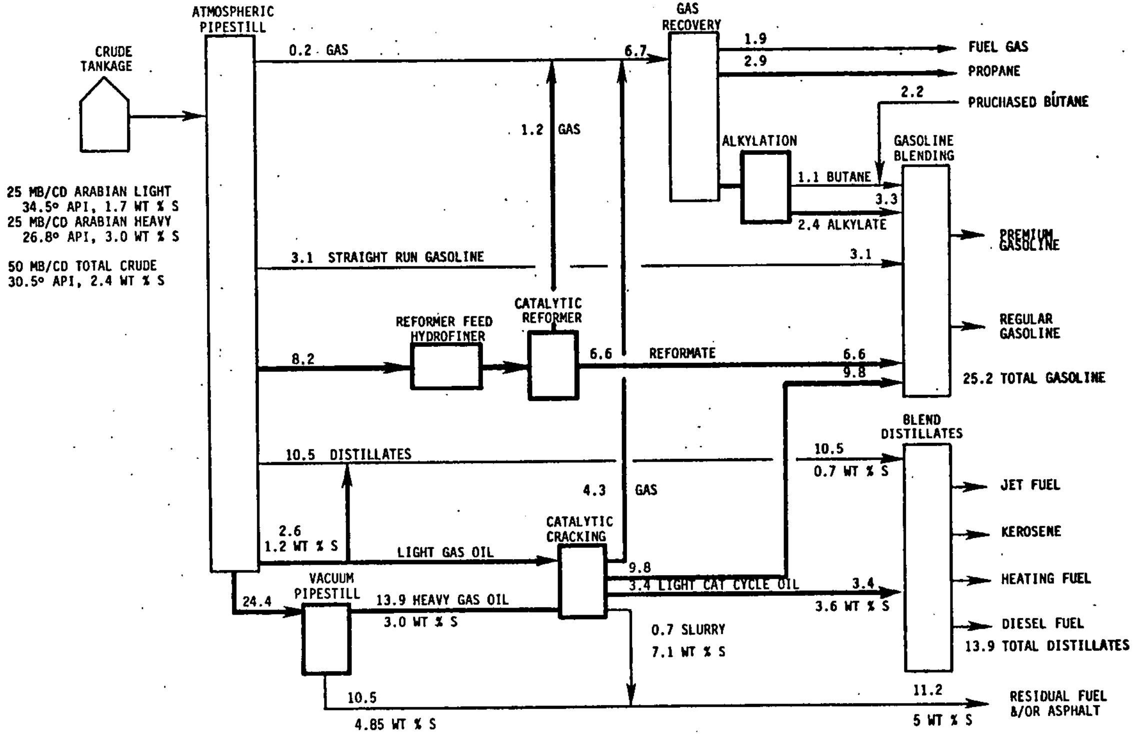


Figure 3-4. Typical Northern Tier Refiner Flow Diagram,
Processing Light and Heavy Arabian
(MB/CD)

The crude tankage, product tankage, product yields, and product qualities discussion of the basic refinery also apply to this typical Northern Tier refinery. Note that the catalytic cracker has 14.5 MB/CD of feed in this case versus the 15.7 MB/CD of feed in the light Canadian crude case, and that the reformer has 8.2 versus 11.9 MB/CD of feed. The result is that this Arabian crude slate produces 4.2 MB/CD (14 percent) less gasoline, 1 MB/CD (7 percent) less distillates, and 4.7 MB/CD (72 percent) more high-sulfur (5 versus 0.9 weight percent) residual fuel.

The short-term alternatives for the typical Northern Tier refinery are the same as those of the basic refinery: developing a market for the high-sulfur residual fuel or obtaining crudes that are somewhat similar to the low-sulfur Canadian crudes. The long-term alternatives for the typical Northern Tier refinery are also similar to those of the basic refinery; because the Northern Tier refinery has additional facilities, however, it may be able to "de-bottleneck" the cat cracker cheaper than the basic refinery could add an entirely new facility. *Whereas these two refineries differ very significantly in the amount of investment in facilities and the number of different processes, they have the same fundamental problem with the significant change in crude-slate.*

3.1.1.5 Variations in Northern Tier Processing Capability

The Northern Tier refineries have three significant variations: (1) some Northern Tier refineries have substantial asphalt markets; (2) some refineries have a degree of hydrotreating and can therefore handle high-sulfur crudes; and (3) three refineries have an additional processing unit to eliminate vacuum pipestill bottoms.

Those Northern Tier refineries with significant asphalt markets already process a much heavier crude than the typical Northern Tier refinery. These refineries have more tankage for this additional heavy material due to the seasonality of the asphalt market. While this ability to process heavy, high-sulfur crude appears to be an asset, it is also a liability since the refinery must be able to receive this crude as a segregated crude. Some pipelines will not segregate crudes, and crudes cannot be mixed with other crudes or the refinery will not be able to make on-specification asphalt.

Many of the Northern Tier refiners have some hydrofining facilities; Figure 3-5 shows the location of these facilities. There are fundamently four types of hydrofining facilities.

1) As discussed in the typical Northern Tier refinery section, 16 of the 21 refineries with reforming capability have a reformer feed hydrofiner that is about equal to the capacity of the reformer. The hydrofiner lowers the sulfur content of the reformer feed to a level that will not contaminate the reformer feed catalyst.

2) Only three of the 15 Northern Tier refiners that have cat cracking process part of the cat cracking feed through a hydrotreater. This unit is called the hydrotreater rather than a hydrofiner because the severity of the processing must be higher in order to lower the sulfur content of the cat feed to a level where the products from the cat cracker meet the sulfur specification.

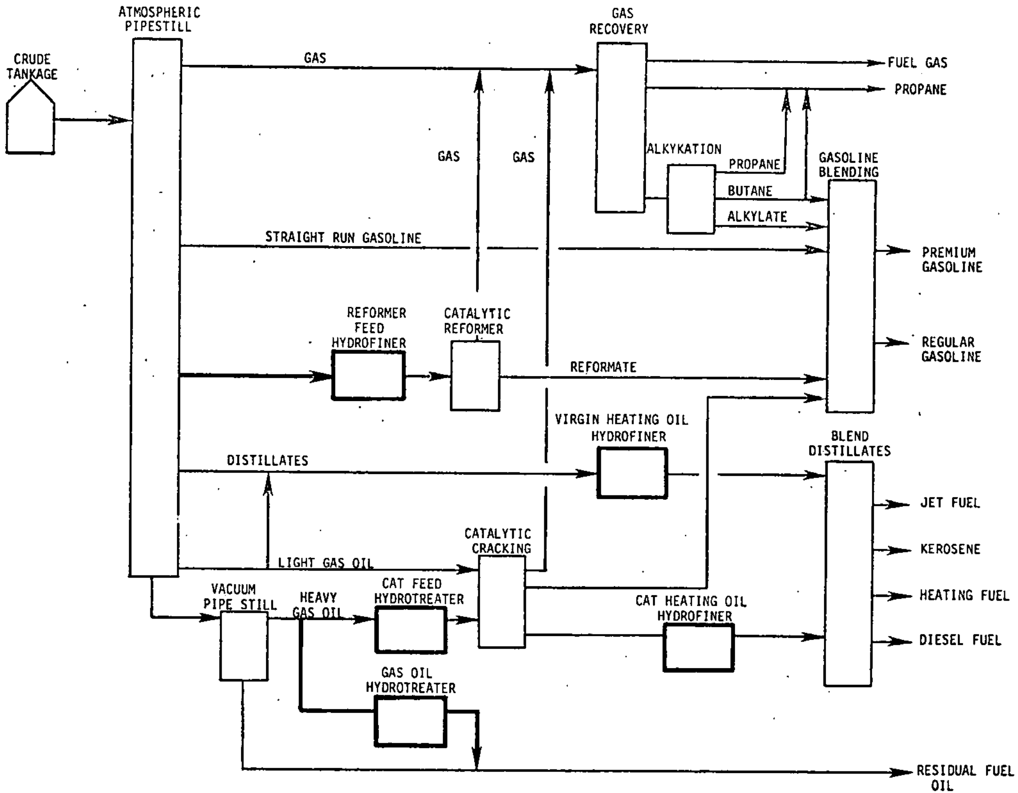

Figure 3-5. Typical Northern Tier Refiner With Hydrofiner

3) Ten of the 21 Northern Tier refineries have distillate hydrofiners of one form or another. Some of these process cat heating oil while others process virgin heating oil directly from the atmospheric pipestill. Again, these units lower the sulfur content of the distillate to meet product specification.

4) Due to their historical low residual fuel oil sales and the comparatively recent reduction in fuel oil sulfur specifications, none of the Northern Tier refineries have a comparatively new processing unit, called a gas oil hydrotreater, which processes vacuum gas oil. The products from this gas oil hydrotreater are low enough in sulfur to blend with the vacuum pipestill bottoms to produce a low-sulfur residual fuel oil.

As shown in Figure 3-6, it is possible to add a coker to process the reduced crude from the atmospheric pipestill or the bottoms off the vacuum pipestill. The products from this coker consist of a coker gas which would be processed through the gas-recovery system; a coker gasoline which, while low in quality, would be blended with the other gasoline components; a coker gas oil which must be processed through catalytic cracking to produce saleable products; and petroleum coke which is typically sold for the manufacturer of electrodes rather than as a substitute for coal. Only three of the Northern Tier refineries have a coker. While this would seem to be advantageous to them, it should be pointed out that these cokers were sized for the crude that these refineries had been processing, not for the signficant volumes of increased resid that would be available with heavier foreign crudes. Therefore, the refineries with cokers are in the same surplus resid position as the typical Northern Tier refinery.

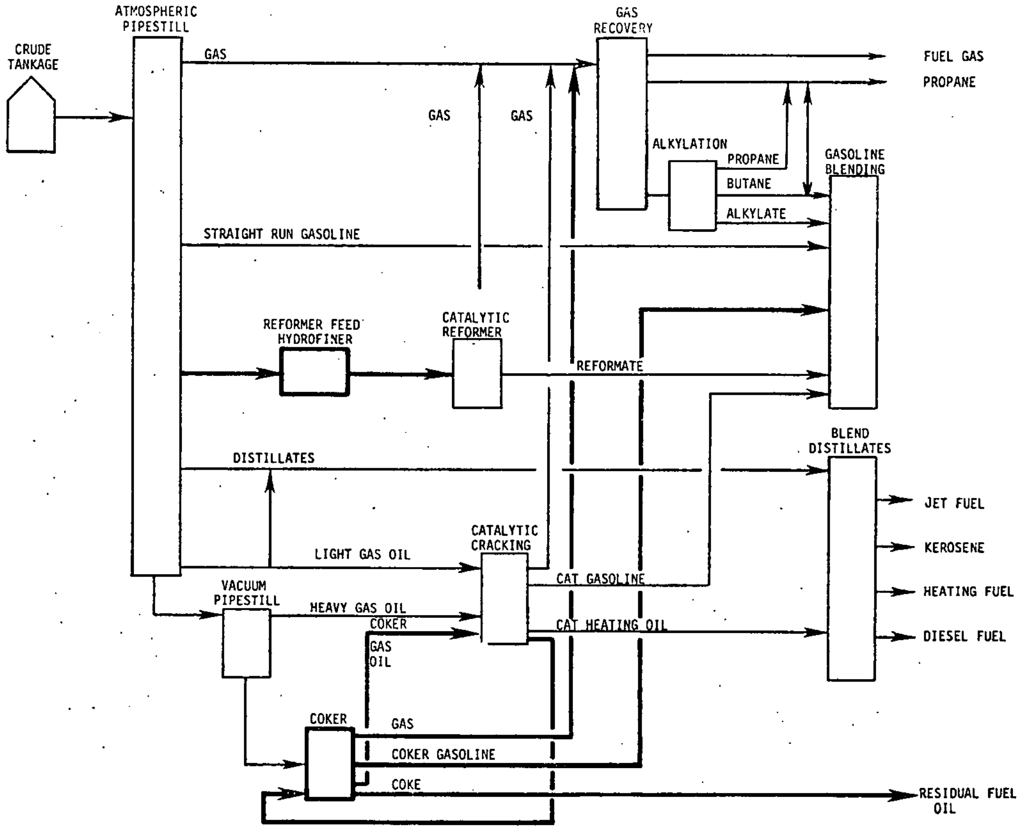


Figure 3-6. Typical Northern Tier Refiner With a Coker

3.1.1.6 Summary

The Northern Tier refineries differ in their abilities to handle heavier, higher-sulfur crudes. The specific situation of each refinery is detailed in Addendum A. It is important to remember that some of the refineries cannot presently handle these heavier, high-sulfur crudes without extensive, expensive, long lead-time modifications to their facilities. Each of these refineries is different in its ability or inability to process and receive these heavier crudes. *For the short term, therefore, these refineries are severely limited in the crudes that they can purchase and process to produce products for their markets.*

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### 3.1.2 Power Plants

Several of the Northern Tier States are fortunate enough to be able to satisfy a significant portion of their electrical demand through hydroelectric generating facilities. Where such facilities are not a practical alternative, coal-fired generating plants have typically been used.

In order to comply with tighter air pollution standards of the early 1970's, however, generating companies were confronted with three options: to clean up emissions from their existing coal-fired facilities; to modify existing plants to burn relatively clean fuels (natural gas or petroleum); or to invest in new plants based on nuclear power.

The decision made by each utility was principally a function of the age of its coal-fired facilities, the growth rate of demand for its electric service, and the long-term availability of a clean fuel alternative. Economics, of course, played an important role in evaluation of alternatives.

There are two emission problems for coal-burning facilities: particulate matter and sulfur dioxide. Particulates can be removed through the use of precipitators or other filtration types of devices. Increasing stack height, although not eliminating particulates, reduces its concentration by dispersing it over a larger area. Sulfur dioxide can be removed through "scrubber" types of devices. As in the case of particulate matter, increasing stack height also reduces concentration through dispersion. Modifying coal-fired facilities to run cleaner fuels requires changing burners and typically requires construction of new receiving and fuel storage facilities. Nuclear plants are expensive and for a variety of reasons require a longer lead time for construction than fossil-fuel plants.

In view of the particular circumstances in each case, three utilities in Northern Tier States elected the petroleum-fired option. These were Lake Superior District Power in Ashland, Wisconsin, Consumers Power in Essexville, Michigan, and Detroit Edison in River Rouge, Michigan. Each of these plants is discussed in detail in Addendum A.

These three oil-fired generating facilities are relatively unique in comparison with other oil-fired utilities in the United States in their use of crude oil rather than residual fuel oil.

Crude oil is actually a mixture of gasoline, heating oil, and heavier materials converted to these products by the refining process. The price of each product is a function of many factors, principal among which is demand. Typically gasoline has a relatively high price, whereas residual fuel oil (which is, as the name implies, the product left after more valuable products have been removed) has a lower price. For economic reasons, therefore, most oil-fired electrical utilities in the United States use residual fuel if available.

Since residual oil was not readily available to the utilities mentioned, due to a lack of domestic supply and/or transportation facilities, and since overland Canadian crude oil was available under import policies at the time, these utilities elected to fire crude oil. Ironically at the present time, crude oil is becoming unavailable to these utilities due to Canadian export policy, while Canadian residual oil has become available due to changes in United States import policies which now allow imports of this product.

### 3.1.3 Synthetic Natural Gas Plant

Natural gas has long been a favorite fuel for home heating and for a variety of industrial uses. It is clean and convenient to use, and has been relatively economical because of price controls. Major investments have been made in natural gas facilities by, among others, residential users, industrial consumers, utilities, and pipeline companies.

Natural gas, because of its nature, can be most economically transported through pipelines. Accordingly, demand for natural gas can best be satisfied by supply from a land-contiguous area. As the growth in demand for natural gas has exceeded available supply, curtailment of deliveries to utility companies has been necessary. Utility companies have responded by ranking their customers into different groupings to allocate the deminished supply. Home owners, for example, have traditionally had a higher priority than industrial users because home owners have no alternate means of generating heat. Furthermore, gas utility companies have often limited new customers to residential users in an attempt to reduce demand.

Notwithstanding these measures, a supply shortfall has still developed. Because of this shortfall, investments in synthetic natural gas (SNG) plants among other alternatives such as LNG ships have been evaluated.

Synthetic natural gas can be manufactured from coal, naphtha, or condensate. Principally because of technology and economics, SNG plants built in the United States to data have used either naphtha or condensate as feedstock. Even in these cases, such plants are relatively high cost. They must also compete with petrochemical plants that use the same feedstocks as their raw materials. Their supply situation may change with lead phasedown and motor gasoline desulfurization programs.

The only SNG plant built in the Northern Tier States is the Consumers Power Plant at Marysville, Michigan. This facility is discussed in detail in Addendum A.

## 3.2 NORTHERN TIER TRANSPORTATION

As Canadian imports of crude oil become decreasingly available to the United States, the Northern Tier States are becoming increasingly dependent on alternate supply lines for crude oil and petroleum products. While long-term solutions to crude oil supply to the Northern Tier States are being developed, an interim period exists during which Canadian imports will be further curtailed while demand for products in the Northern Tier continues to grow. During this interim, existing and expandable supply lines for crude and products to the Northern Tier will become critically important to energy availability and energy economics.

Fortunately, a multiplicity of transportation methods exist for moving crude oil and products into virtually all parts of the Northern Tier. These alternatives are crude oil and product pipelines, barge transportation via rivers and lakes, deepwater seaports for crude importation, and rail (tank car) transportation. These are described in detail in Addendum B.

The transportation options considered in this study are only those which can have an impact on the Northern Tier areas during the period between mid-1976 through 1977. Some of these transportation methods have the potential to help alleviate a growing shortfall of crude/product supply which would otherwise occur beyond 1977, but analysis beyond 1977 was conducted only as the restrictive time frame of this study permitted.

This section of the report first discusses the general transportation situation in the Northern Tier States (subsection 3.2.1) and then presents more detailed information on the various modes of transportation available for movement of crude oil and petroleum products (pipelines, barges, and rail transport).

### 3.2.1 Transportation Summaries by Area

Each area within the Northern Tier has different limitations on transportation capability. Limitations depend on the transportation which is currently in place and the geography of the particular area under consideration.

In terms of transportation capabilities and transportation problems, the Northern Tier may be characterized as four separate areas. Each of these areas has similar or highly related energy supply problems and transportation capabilities. These areas are:

1) Southern Michigan

2) Wisconsin, Minnesota, Eastern North Dakota, and Northern Michigan

3) Western North Dakota, Montana, and Eastern Washington

4) Western Washington

The transportation capabilities of each of these four areas are largely isolated from capabilities in other areas. The composition of transportation capability in each area is quite different. Each area has its own set of transportation economics for crude oil and products, and there is very little overlap in markets between areas.

For interim supply of crude oil and products, only existing facilities and facility expansions which do not require heavy capital investment can be considered. The consumers of crude oil in the Northern Tier are convinced that long-term supplies of crude will be available within the next five to six years. Potential investors are, therefore, unwilling to commit long-term capital to short-term transportation solutions. Short-term, high-cost solutions to energy supply problems may be required for some areas--particularly beyond 1977. Each area and its general capabilities and problems in crude and product transportation are discussed in the following paragraphs.

3.2.1.1 Southern Michigan

Southern Michigan is a Northern Tier area which can best utilize existing pipeline systems with little or no additional investment requirements. The pipelines companies serving Michigan indicate that spare capacity seems strained to supply southern Michigan from Chicago with crude oil through 1977, and crude supply into Chicago is severely limited. Such plans must consider not only growing demand for products in Michigan, however, but also the requirement to supply U.S. or foreign crude oil through Michigan to Buffalo, New York. (Even if exchanges can be effected with Canada, such crude oil would likely take the same route.) Total additional volumes moving through the pipeline system may cause an overload and a consequent supply difficulty in Michigan. Supply shortage is especially likely to occur if Michigan should experience a severe winter in 1976-77 and 1977-78 or if gasoline demand is larger than predicted for the summer months.

Should supply problems arise, southern Michigan has a possible alternate supply possibility via the St. Lawrence Seaway. This alternative could only be feasible during eight to nine months per year. Traffic on the seaway is restricted to limited draft vessels, and there is a scarcity of these small lake tankers. Also, not all refiners have marine receiving facilities. Michigan refiners consider the seaway route to be a very high-cost solution, therefore, and certainly this alternative should be considered only as a high-cost, very short-term solution to supply problems.

Transportation of crude oil to southern Michigan via existing pipeline systems costs from 40¢ to 70¢ per barrel, according to source and destination. Transporting domestic crude oil from the Gulf Coast to Michigan via the St. Lawrence Seaway, on the other hand, costs substantially more--ranging up to $5 per barrel. There is also the possibility of bringing in foreign crude oil through the St. Lawrence Seaway. North African crude, for example, could be transported into Michigan for something like $1.20 per barrel. The same crude, via pipeline from the Gulf Coast, would incur transportation costs of about $1.05 per barrel. Few refiners in Michigan have the capability to receive crude via the seaway, however, which means that receiving facilities would have to be constructed. Such construction probably could not be completed during the 18-month time frame of this study. Even with receiving facilities, large additional storage capacity would be required in order to make the seaway route feasible for year-around supply due to the seasonal problems involved in seaway usage.

#### 3.2.1.2 Wisconsin, Minnesota, Eastern North Dakota, and Northern Michigan

This Northern Tier area combines a heavy dependence on Canadian crude oil with a very limited capability for receiving crude oil through existing pipelines other than those from Canada.

The Williams product pipeline has transported some crude oil into this area (by batching crude oil with products) and is planning an expansion of capacity by 80 MB/CD in late 1977.

The Portal pipeline system also supplies North Dakota crude oil into Minnesota but not in the volumes necessary to supply both the Minneapolis area and the Duluth/Superior area refineries.

There is some capability for transporting additional finished products into this area via the existing pipeline system. This solution to energy supply would create a changing market, however, and would severely impact the refining industry within this general area.

Barging crude oil or products up the Mississippi River is an important capability in this area of the Northern Tier. There is currently spare capacity insofar as barges are concerned, but the river is somewhat bottlenecked at Lock 26 in Illinois (see paragraph 3.2.4). Currently, Lock 26 on the Mississippi causes a one-day delay each way in shipments. The Mississippi River approach to transporting more crude or product into southern Minnesota is feasible for eight months of the year. If this area is to utilize this transportation alternative, additional storage capability and/or the scheduling of crude receipts from other sources (e.g., Lloydminster crude during the winter months when Canada does not want it) to cover the other four months of the year would be necessary.

Beyond pipeline and river transportation solutions, there is also the possibility of using high-cost unit trains for tank-car shipments of crude oil into Minnesota via the Portal pipeline. This alternative could have a substantial impact on this area's crude supply in the latter part of 1977 if it is required.

The cost for crude shipments into this area via pipeline is approximately $1.03 per barrel. In comparison, crude oil shipment by barge via the Mississippi River is $1.05 to $1.40 per barrel, counting the possibility of additional costs for terminal and storage facilities. Tank car shipments via unit trains could move crude oil into the area at about $3.07 per barrel into Minneapolis.

### 3.2.1.3 Western North Dakota, Montana, and Eastern Washington

This is a relatively isolated area insofar as alternate pipeline transportation is concerned. Existing pipeline systems primarily supply crude oil from Canada, with an additional line from Wyoming. While the reversal of another existing pipeline is possible for shipping in Wyoming crude oil, this is only marginally attractive because of limitations to the processing of heavy Wyoming crudes.

Unit train shipment of crude oil to Billings, at approximately $2.23 per barrel average cost, is a possibility. This solution has, however, caused environmental reaction on the transportation route from Washington to Montana and North Dakota (see paragraph 3.2.4.3). This unit train solution would require about six months for implementation, and no capital has as yet been committed to such a solution. For this reason, the earliest impact of unit train shipments could not come before the first half of 1977.

There is a possibility for additional product shipments into eastern Washington along the Chevron product line from Salt Lake City. Some product has also been barged up the Columbia River into the northern extremity of this pipeline from the Washington refineries, but indications are that the pipeline is currently at capacity. An indirect product supply to Montana could be by supplying Denver via the Chase pipeline, which would stop the product flow from Billings to Casper and from Casper to Denver.

If the western North Dakota, Montana, and eastern Washington area has unusually high demand for either winter or summer, even high-cost, short-term solutions may be very strained to meet the demand.

3.2.1.4 Western Washington

Of all the Northern Tier areas, western Washington will be affected least by the loss of Canadian crude imports. Although this area was totally dependent on Canadian crude via the TransMountain pipeline, it can alternatively receive crude through existing harbor facilities via tanker. Some of these facilities can handle large crude carriers in deep water. Tanker traffic in the Puget Sound area is a source of continuing concern in Washington State, principally because of the potential for oil spills. This environmental aspect is discussed in Volume II of this study.

For some of the interim period, western Washington will become more dependent on foreign crude oil (other than Canadian) for supplanting Canadian crude and for satisfying growing demands for petroleum products. Short-term plans for processing foreign crude make this area vulnerable to crude oil embargo. Over the long horizon, however, the Washington refineries planning to run Alaskan North Slope crude will be the first to receive shipments of this crude and will not be dependent on long-term transportation solutions. Thus, some vulnerability to oil embargo will disappear in 1977.

3.2.2 Pipeline Transportation

The United States has extensive crude oil and petroleum products pipeline transportation systems. The crude oil transportation system has built up in response to the need for gathering crude oil (from domestic sources, foreign sources on the North American continent, or importation seaports) and transporting it to refining centers. The product system has built up in response to the need for shipping finished products from refining centers to market areas for ultimate consumption.

Major routes of crude oil movement are shown in Figure 3-7. Major routes for product movement are similarly illustrated in Figure 3-8.

In the Northern Tier, much of the crude oil pipeline system has been developed specifically for transporting Canadian crude to Northern Tier refining centers and distributing the resulting products to Northern Tier marketing areas. Now, with the phasing out of Canadian imports, new supply lines must be established. Existing systems can, to some extent, be utilized for transporting crude oil to the Northern Tier to replace Canadian crude oil. Some additional product can also be supplied through existing product pipelines. There is also a limited possibility for shipment of crude oil in lines now dedicated to shipment of products.

The existing crude pipelines in the Northern Tier are shown, on a state-by-state basis, in Figures 3-9 through 3-14. Existing petroleum product lines in the Northern Tier are similarly illustrated in Figures 3-15 through 3-21. Pipelines, where available, are the most economical means for crude oil product transportation. Table 1 shows a representative group of tariffs for pipelines (with gathering costs for crude lines).

As indicated earlier, the Northern Tier States--because of geography, existing transportation systems, and isolated market areas--fall rather naturally into four general areas. Each of these is discussed in terms of pipeline capabilities and possibilities in the following paragraphs.

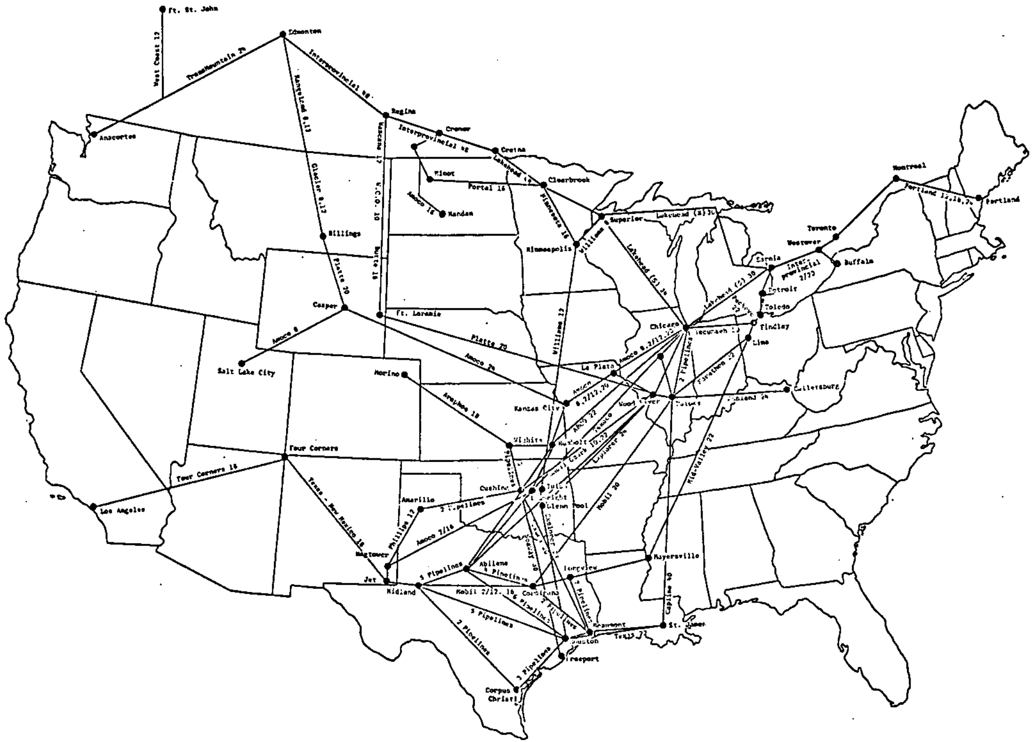



Figure 3-7. Major U.S. Crude Oil Supply Pipelines

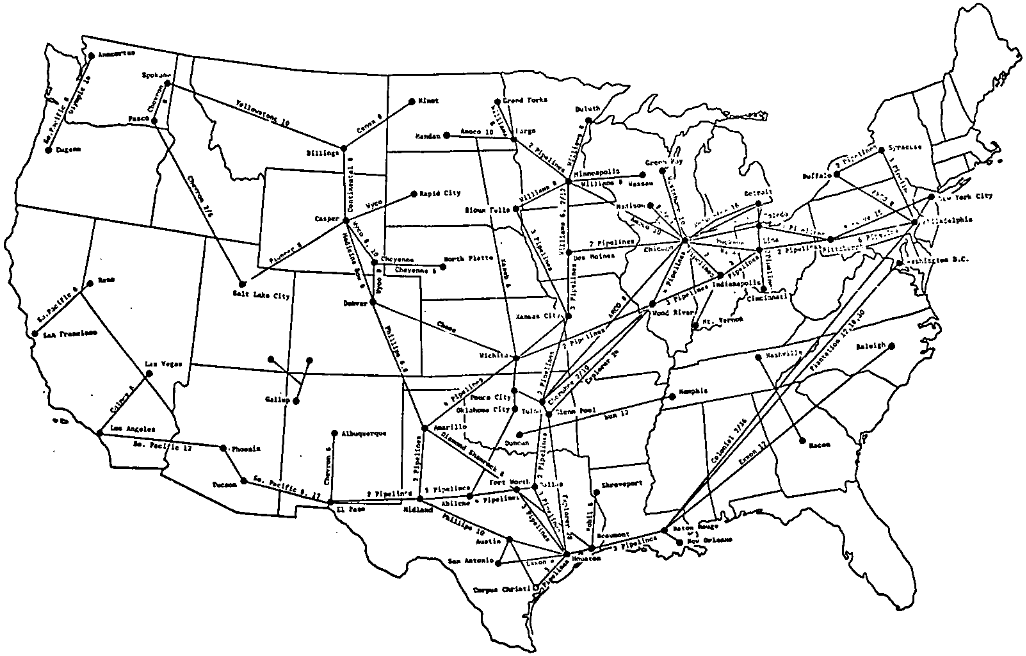
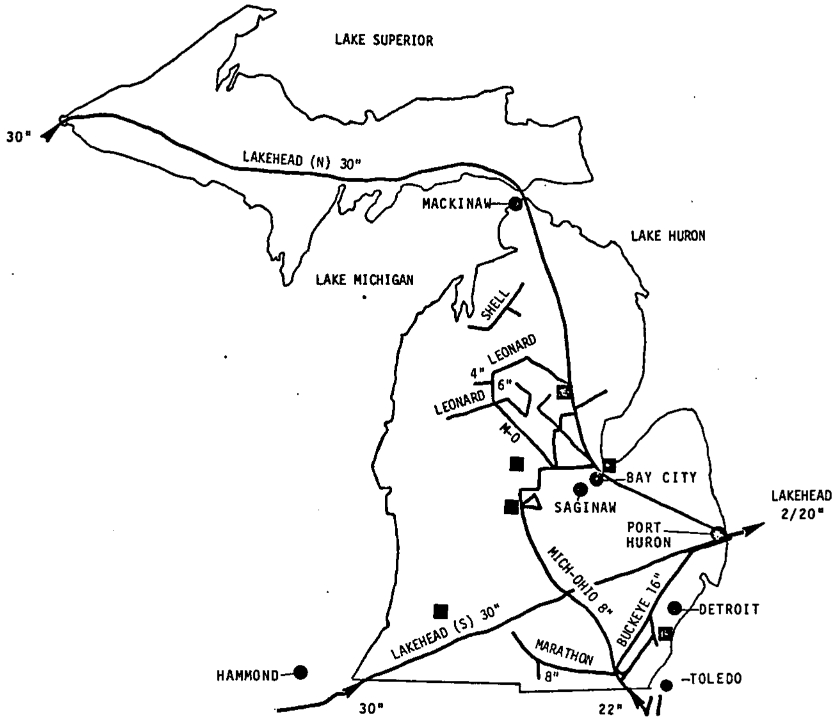



Figure 3-8. Major U.S. Products Supply Pipelines

MICHIGAN




● CITY
■ REFINERY
—— PIPELINE (Crude Oil)

WISCONSIN

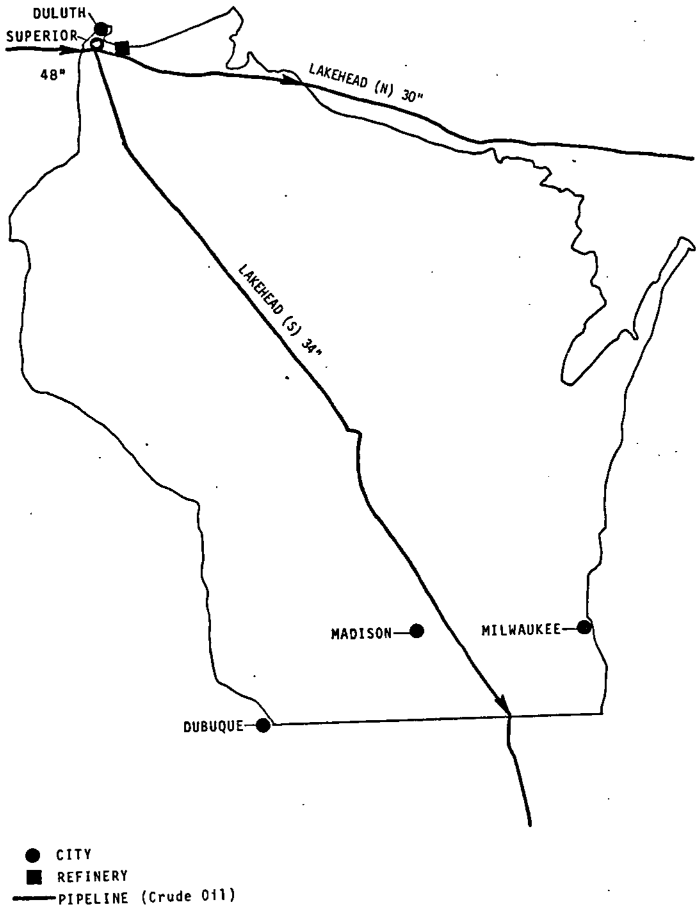



Figure 3-10. Crude Oil Pipelines - Wisconsin

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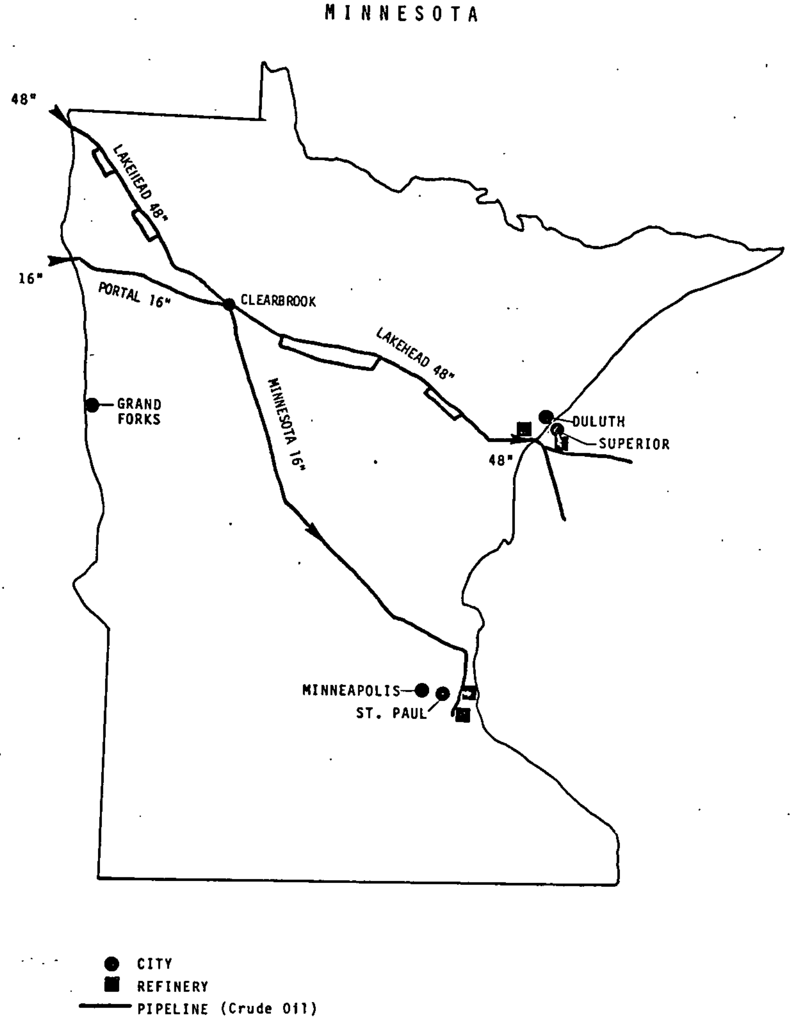


Figure 3-11. Crude Oil Pipelines - Minnesota

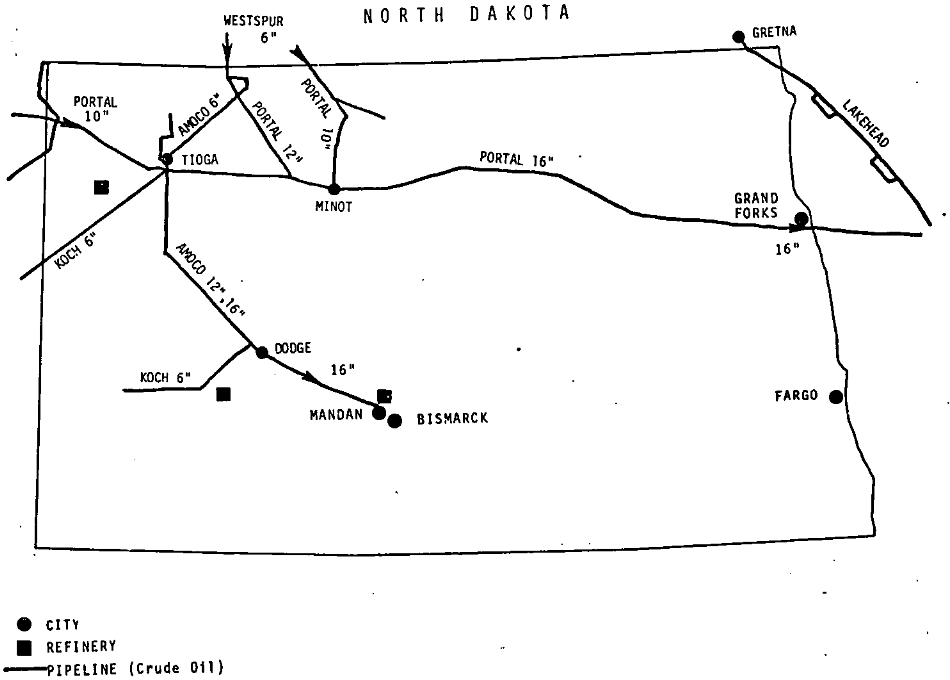


Figure 3-12. Crude Oil Pipelines - North Dakota

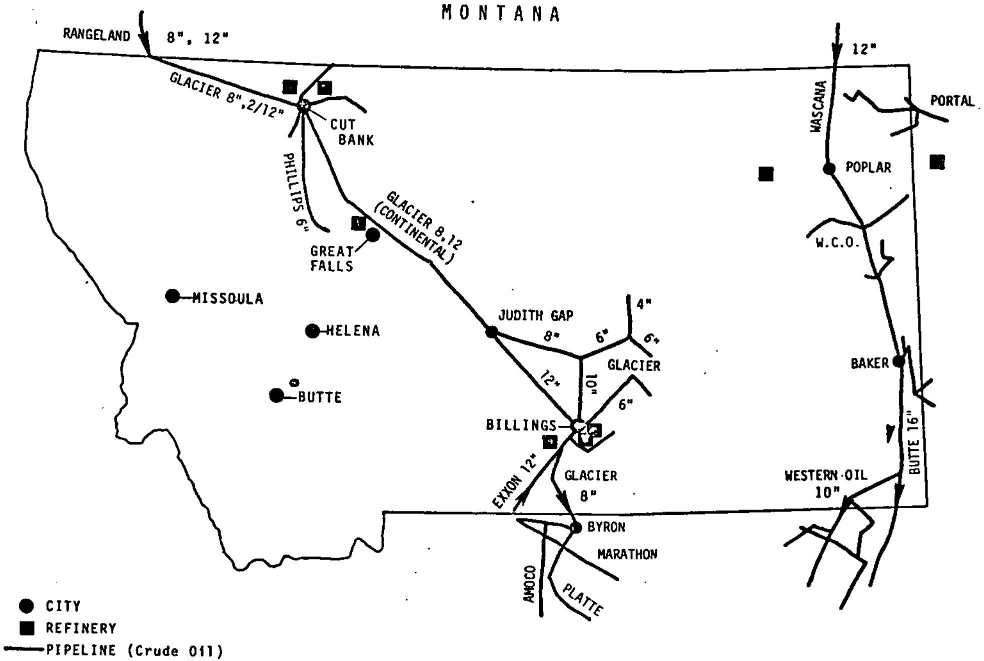


Figure 3-13. Crude Oil Pipelines - Montana

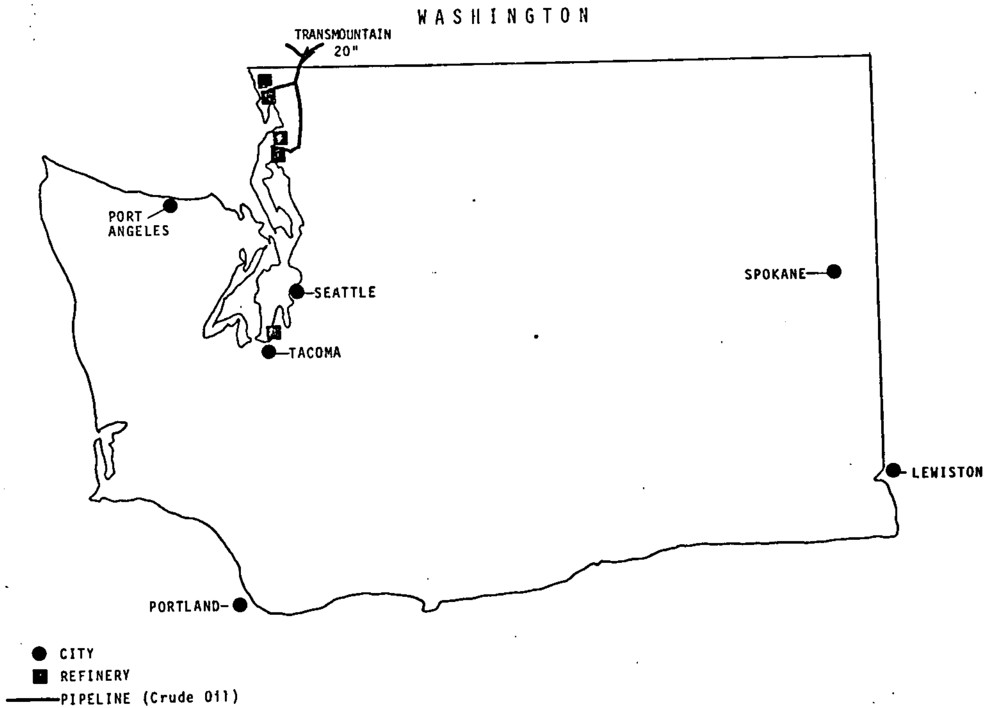


Figure 3-14. Crude Oil Pipelines - Washington

MICHIGAN

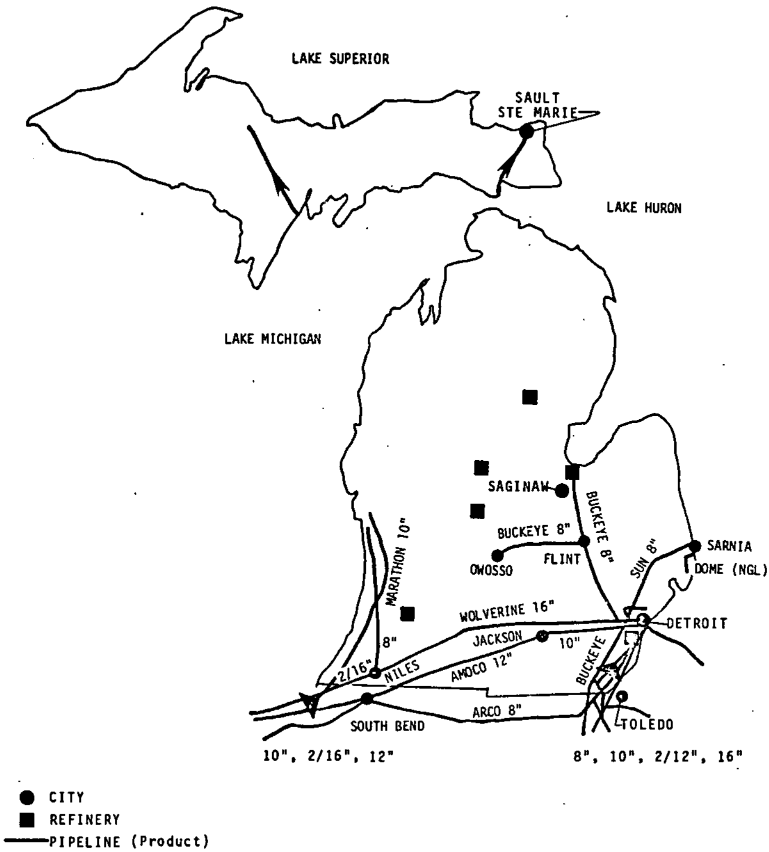


Figure 3-15. Product Pipelines - Michigan

# WISCONSIN

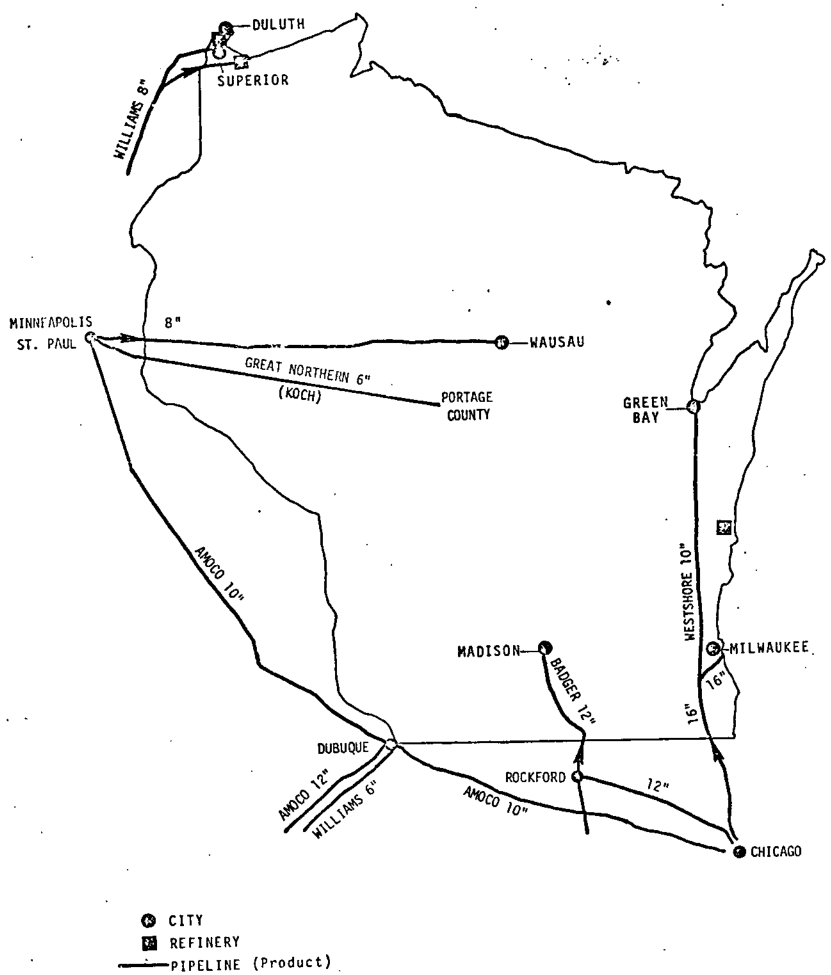


Figure 3-16. Product Pipelines - Wisconsin

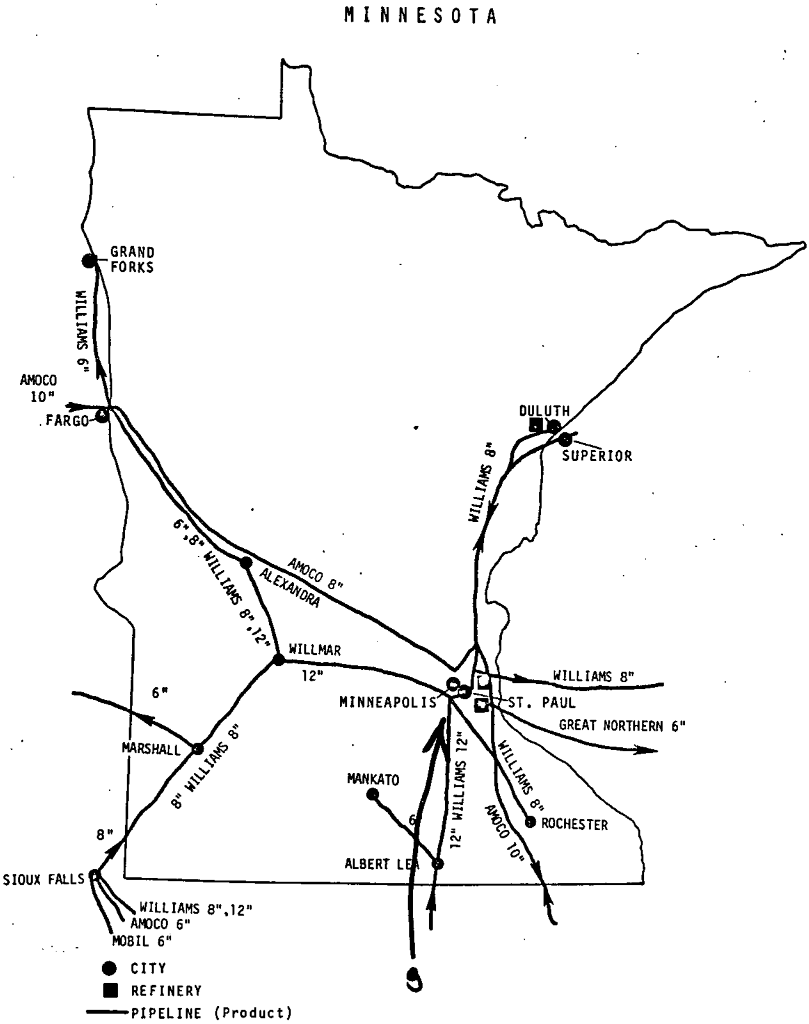


Figure 3-17. Product Pipelines - Minnesota

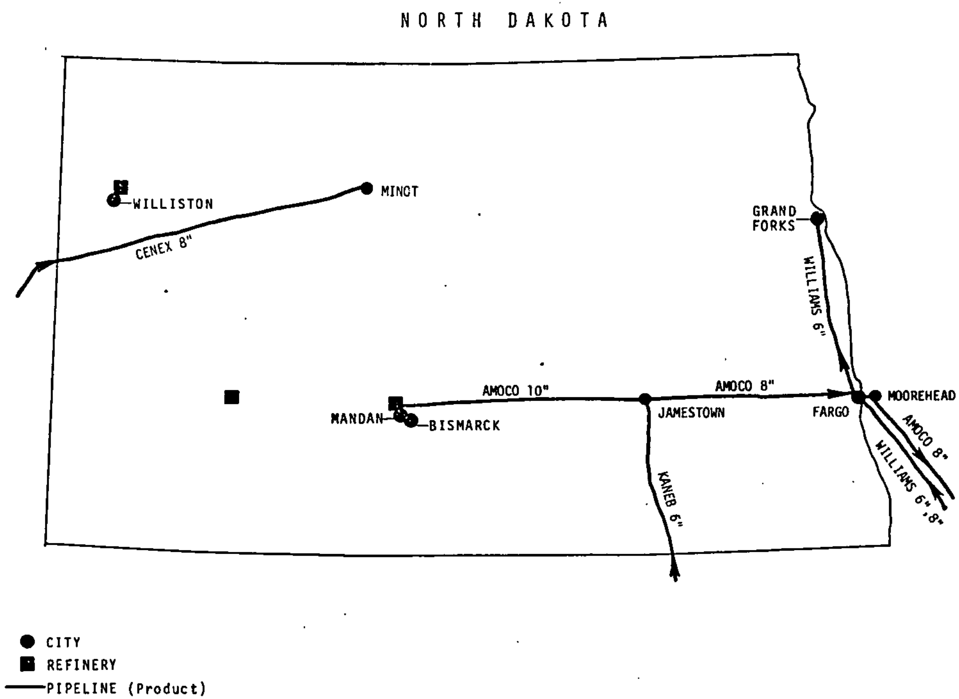


Figure 3-18. Product Pipelines - North Dakota

MONTANA

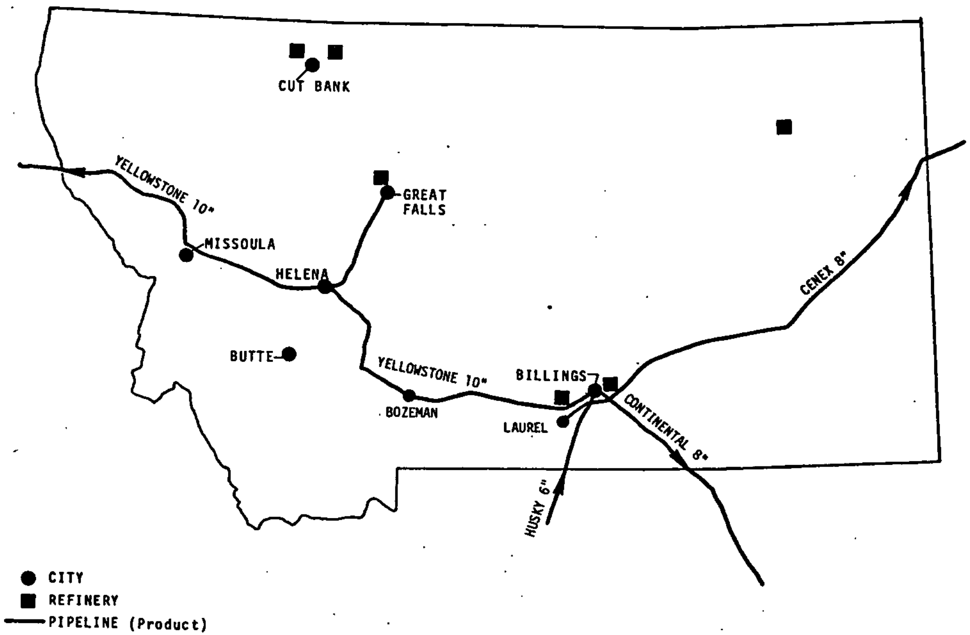


Figure 3-19. Product Pipelines - Montana

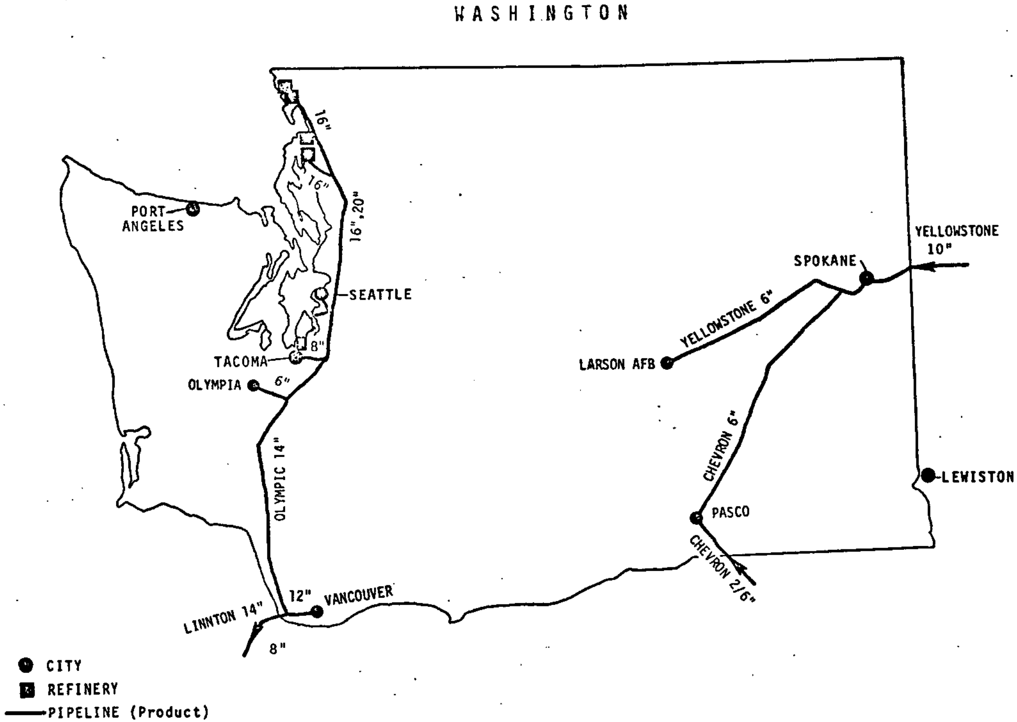


Figure 3-20. Product Pipelines - Washington

## TABLE 1

## REPRESENTATIVE PIPELINE TARIFFS

(Sheet 1 of 4)

| ORIGINATION POINT OR AREA | DESTINATIONS | TARIFF ¢/BBL | GATHERING COSTS ¢/BBL | ROUTES |
|---|---|---|---|---|
| St. James Terminal, Louisiana | Patoka, Illinois | 22.0 | | Shell Pipeline Corporation (Capline) |
| St. James Terminal, Louisiana | Detroit, Michigan | 36.5 | | Shell Pipeline Corporation, Patoka, Illinois; Marathon Pipeline Company, Lima, Ohio; Buckeye Pipeline Company |
| Coates, Oklahoma | Wood River, Illinois | 36.0 | | Wesco Pipeline Company, Cimmaron Junction, Oklahoma; Continental Pipeline Company, Cushing, Oklahoma; Shell Pipeline Corporation |
| New Mexico<br>Northwest Texas | Cushing, Oklahoma | 25.0 | 6.0[1] | Texas-New Mexico Pipeline; Shell Pipeline Corporation |
| New Mexico<br>Northwest Texas | Arkansas City, Kansas | 61.0 | 6.0[1] | Texas-New Mexico Pipeline; Shell Pipeline Corporation, Cushing, Oklahoma; Texaco-Cities Service Pipeline, Eldorado, Kansas; Mesco Pipeline |
| Humboldt, Kansas | Pine Bend, Minnesota<br>St. Paul Park, Minnesota | 60.0<br>61.0 | | Williams Pipe Line Company |
| Cushing, Oklahoma | Lawrenceville, Illinois | 20.0 | | Texas Pipeline Company |
| Cushing, Oklahoma | Lockport, Illinois | 22.0 | | Texas Pipeline Company, Patoka, Illinois; Texaco-Cities Service Pipeline Company |
| Midland, Texas<br>Colorado City, Texas | Cushing, Oklahoma<br>Cushing, Oklahoma | 21.0<br>19.0 | | Texas Pipeline Company, Cushing, Oklahoma; Texaco-Cities Service Pipeline Company |
| St. James, Louisiana | Blue Island, Illinois | 31.75 | | Texas Pipeline Company, Patoka, Illinois; Chicap Pipeline Company |
| Nederland, Texas | Cushing, Oklahoma<br>Longview, Texas<br>Silsbee, Texas<br>Winnsboro, Texas<br>Wynnewood, Oklahoma | 40.5<br>17.5<br>12.5<br>21.4<br>36.4 | | Texoma Pipeline Company |
| Longview, Texas | Cushing, Oklahoma<br>Winnsboro, Texas<br>Wynnewood, Oklahoma | 25.0<br>6.0<br>20.9 | | Texoma Pipeline Company |

[1] Gathering cost when gathered by Texas-New Mexico Pipeline.

## TABLE 1

## REPRESENTATIVE PIPELINE TARIFFS

(Sheet 2 of 4)

| ORIGINATION POINT OR AREA | DESTINATIONS | TARIFF ¢/BBL | GATHERING COSTS ¢/BBL | ROUTES |
|---|---|---|---|---|
| Winnsboro, Texas | Cushing, Oklahoma<br>Wynnewood, Oklahoma | 21.0<br>17.0 | | Texoma Pipeline Company |
| Cushing, Oklahoma | Joliet, Illinois | 24.75 | | Texaco-Cities Service Pipeline Company, Mobil Junction; Mobil Pipeline Company |
| | | 16.0 | | Texaco-Cities Service Pipeline Company, Cushing, Oklahoma; Texas Pipeline Company, Patoka, Illinois; Texaco-Cities Service Pipeline Company, Mobil Junction; Mobil Pipeline Company |
| Moweaqua, Illinois | Toledo, Ohio | 29.0 | | Texaco-Cities Service Pipeline Company, Dyer Junction, Indiana; Tecumseh Pipeline Company, Cygret, Ohio; and Buckeye Pipeline Company |
| Cushing, Oklahoma | Eldorado, Kansas | 18.0 | | Texaco-Cities Service Pipeline Company |
| Cushing, Oklahoma | Augusta, Kansas | 23.0 | | Texaco-Cities Service Pipeline Company, Valley Center, Kansas; Mobil Pipeline Company, Augusta, Kansas |
| Seminole, Oklahoma | Lockport, Illinois | 28.75 | | Texas Pipeline Company, Seminole, Oklahoma; Texaco-Cities Service Pipeline Company, Cushing, Oklahoma; Texas Pipeline Company, Patoka, Illinois; Texaco-Cities Service Pipeline Company |
| Cushing, Oklahoma | Lockport, Illinois | 23.5 | | Texaco-Cities Service Pipeline Company, Cushing, Oklahoma; Texas Pipeline Company, Patoka, Illinois; Texaco-Cities Service Pipeline Company |
| Cushing, Oklahoma | Lawrenceville, Illinois | 23.5 | | Texaco-Cities Service Pipeline Company, Cushing, Oklahoma; Texas Pipeline Company |
| Cushing, Oklahoma | Lima, Ohio | 33.0 | | Shell Pipeline Corporation, Wood River, Illinois; Marathon Pipeline Company, Lima Junction, Ohio; Sohio Pipeline Company |
| Cushing, Oklahoma | Toledo, Ohio | 37.5 | | Shell Pipeline Corporation, Wood River, Illinois; Marathon Pipeline Company, Lima Junction, Ohio; Buckeye Pipeline Company |

## TABLE 1

## REPRESENTATIVE PIPELINE TARIFFS

(Sheet 3 of 4)

| ORIGINATION POINT OR AREA | DESTINATIONS | TARIFF ¢/BBL | GATHERING COSTS ¢/BBL | ROUTES |
|---|---|---|---|---|
| Various Oklahoma - Cushing - Lincoln County, Carter County, Garvin County | Wood River, Illinois | 24.0 | | Shell Pipeline Corporation |
| Cashion, Oklahoma | Wood River, Illinois | 15.0 | 20.0[1] | Shell Pipeline Corporation |
| St. James, Louisiana | Auburn Junction, Indiana | 41.0 | | Shell Pipeline Corporation, Patoka, Illinois; Texas Pipeline Company, Patoka Junction, Illinois; Texaco-Cities Service Pipeline Company, Dyer Junction, Indiana; Tecumseh Pipeline Company |
| Texas - North, West Central, West, East Texas | Joliet, Illinois | 33.-35. | 8-27. | Mobil Pipeline Company, Patoka, Illinois; Chicap Pipeline, Mokena Station, Illinois; Mobil Pipeline |
| Salem, Illinois | Joliet, Illinois | 25.0 | 10.0 | |
| Crossroads, New Mexico | Joliet, Illinois | 37.0 | 12.0 | |
| Addington, Hearlton, Purcel, Oklahoma | | | | |
| Pauls Valley, Ringling, Oklahoma | Lemont, Illinois | 26.0 | | Arco Pipeline Company, Cushing, Oklahoma; Pure Transportation Company |
| Dolivar, Manuel, Pool | Lemont, Illinois | 26.0 | 12.0 | |
| Tribbey Junction, Oklahoma | Caney, Kansas | 7.5 | | Arco Pipeline Company |
| Colorado City, Texas | Cushing, Oklahoma | 14.0 | | Arco Pipeline Company |
| New Mexico | Cushing, Oklahoma | 21.0 | | Amoco Pipeline Company |
| North & Northwest Texas | Sugar Creek, Missouri | 26.0 | | |
| | Whiting, Indiana | 38.0 | 8.5-23.0[2] | |
| | Wood River, Illinois | 35.0 | | |
| Oklahoma, Kansas, North Texas | Sugar Creek, Missouri | 12.0 | | Amoco Pipeline Company |
| | Whiting, Indiana | 27.0 | | |
| | Wood River, Illinois | 24.0 | | |
| Oklahoma Station | Rock Island, Indiana | 28.0 | 10.0 | Amoco Pipeline Company |
| | East Chicago | 30.0 | 20.0 | |
| Midland, Texas | East Chicago | 33.0 | | Amoco Pipeline Company |

1 Gathering cost when gathered by Continental Pipeline Company.

2 Most at 8.5.

## TABLE 1

## REPRESENTATIVE PIPELINE TARIFFS

(Sheet 4 of 4)

| ORIGINATION POINT OR AREA | DESTINATIONS | TARIFF ¢/BBL | GATHERING COSTS ¢/BBL | ROUTES |
|---|---|---|---|---|
| New Mexico Station | East Chicago, Illinois<br>Griffith, Indiana<br>Canton, Ohio | 41.75<br>43.0<br>67.5 | 6.0<br>6.0<br>6.0 | Amoco Pipeline Company |
| Nederland, Texas | Pine Bend, Minnesota<br>St. Paul Park, Minnesota | 101.50<br>102.50 | | Texoma Pipeline Company, Cushing, Oklahoma;<br>Arco Pipeline Company, Humboldt, Kansas;<br>Williams Pipe Line Company |
| Lake Charles, Louisiana<br>Port Neches, Texas<br>Port Arthur, Texas<br>Pasadena, Texas | Dallas, Texas & Related<br>Tulsa, Oklahoma<br>St. Louis, Missouri<br>Wood River, East St. Louis<br>Peotone, Illinois<br>Griffith, Hammond, Indiana | 20.0-22.0<br>31.0-33.0<br>38.5-40.5<br>38.5-40.5<br>45.4-47.5<br>45.5-47.5 | | Explorer Pipeline Company |
| Tulsa, Oklahoma | St. Louis, Wood River, ILL<br>Peotone, Illinois<br>Griffith, Hammond, Indiana | 27.0<br>34.0<br>34.0 | | Explorer Pipeline Company |
| Wood River, Illinois | Griffith, Hammond, Indiana | 16.0 | | Explorer Pipeline Company |
| Griffith, Indiana | Marysville, Michigan<br>Kalamazoo County, Michigan<br>Stockbridge, Michigan | 15.0<br>9.0<br>11.0 | | Interprovincial Pipeline Company |
| Stockbridge, Michigan | Marysville, Michigan | 7.5 | | Interprovincial Pipeline Company |
| Lewiston Station, Michigan | Essexville, Michigan | 8.5 | | Interprovincial Pipeline Company |

### 3.2.2.1 Southern Michigan Pipelines

Southern or "lower" Michigan's petroleum product market is supplied by product lines from outside the state and by six refining centers located in central, eastern, and southeastern sections of the state.

Product lines (previously shown in Figure 3-15) run from the Chicago refining areas and supply the western portion of lower Michigan (along Lake Michigan) as well as the Detroit area. Some petroleum products are moved into the southeastern portion of the state from refining areas to the south of Ohio.

Refining centers, which supply products to the eastern section of southern Michigan and also to the Detroit area, receive crude oil from four sources (see Figure 3-9 for a diagram of crude pipelines).

1) Canadian crude oil flows into Michigan through the northern branch of the Lakehead pipeline system entering lower Michigan at its north tip. This line carries Canadian and North Dakota/Montana crude oil both to and through Michigan. To the north of Lake Erie, the northern branch of the Lakehead pipeline is reunited with the southern branch as Lakehead moves back into Canada. A stub line on further east on the Lakehead system eventually supplies crude to Buffalo, New York.

2) Canadian, domestic, and foreign crude from the southern branch of the Lakehead pipeline enters Michigan at its southwest corner. Domestic crude and foreign crude from the Gulf Coast enter this line in the Chicago area after being transported north through crude trunklines.

3) Domestic and foreign crude enters Michigan at its southeast corner. With the exception of Mid Valley (which is full), this supply is provided by a branch from the same basic trunklines which supply crude to the Chicago area.

4) Crude oil is provided to refining centers from oil production areas in Michigan.

Pipelines in the central section of southern Michigan interconnect the three major pipeline crude sources and, in addition, gather and transport oil produced in Michigan.

As the Canadian phase-out of exports to the U.S. continues, Michigan's access to Canadian crude shipped through the Lakehead system will steadily diminish to zero unless exchanges can be put into effect with Canada.

While the western portion of southern Michigan should have no supply problem as long as crude oil is available for processing in Chicago, the central and eastern portions of the state, including Detroit, will be affected by the Canadian crude oil curtailment.

Additional crude oil to replace loss of Canadian imports and to support expanding demand for products in Michigan must come either through the Lakehead system from Chicago or through expanded deliveries from the trunklines at the southeastern corner of the state. (Although indigenous crude production is rising in Michigan, total increments to production are not large enough to replace the impending loss of Canadian imports.)

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It is important to remember that the crude oil pipelines into Chicago and the lines supplying crude at the southeast corner of Michigan are essentially two branches of a system of trunklines which move crude oil up the Mississippi Valley and through middle America. Transportation costs (tariffs) for pipelining crude oil from the Gulf Coast into Michigan range between 40 cents and 70 cents per barrel.

While the capacity of the basic trunkline system moving crude oil to Chicago and the upper Midwest is very large (1.5 million barrels per day in 1976), it is also facing a very large growth in demand--especially if it is used to supply replacement crude to the Northern Tier on either an interim or long-term basis. This trunkline system must continue to satisfy growing demand in Chicago and the Midwest. It must also accommodate growing demand for products in Michigan. In replacement of Canadian supplies, the trunkline system will also be used to supply oil which moves eventually into Buffalo, New York. Products manufactured in Chicago and in refining areas south of Michigan are also made from crude shipped through this basic trunkline system.

Interviews with pipeline companies making up the major trunklines indicate that some spare capacity exists and that additional capacity in some cases can be created along these lines. The cost of increased capacity by looping is estimated to be in the range of 2.5 cents to 4.5 cents per barrel per 100 miles of original line length. Actual tariffs will vary from this amount depending on marketing and other considerations. (Looping of pipelines at bottleneck points, installation of additional pumping horsepower, and other methods of pipeline expansion are discussed in a later subsection). Projections by pipeline companies indicate that a capability for moving a total of 150,000 additional barrels a day of crude oil through the basic trunklines can be developed during 1977 and 1978. This figure may, in fact, be conservative. Individual projections from pipeline companies are based on competitive probability. The 150 MB/CD figure is actually the sum of projected additional throughputs. Since two or more competing pipelines may have assumed that they will be the carrier selected for a single customer's shipments, available capacity for the basic trunkline system may be understated.

The pipeline company projections also indicate that available capacity to move additional crude into Michigan exists. Projections indicate that an additional 50 MB/CD can be moved into Detroit from Marysville and 10 MB/CD into Alma from Bay City. Capacity beyond this point, however, will require major pipeline investments. The short-term expansions appear large enough to provide adequate crude supply to Michigan through 1977. An unusually cold winter in 1977 could, however, change this availability picture (as could an unusually high gasoline demand during the summer of 1977), and the result could be shortages in petroleum products.

Beyond 1977, the existing Midwest and Michigan crude delivery systems--even with use of all spare capacity and short-term expansions--may be inadequate to satisfy demands in the Midwest and Michigan. Traditional growth in petroleum demand for the Midwest area, including Michigan, is 2 to 3 percent per year. Elimination of Canadian imports will add another requirement amounting to some 4 percent of total crude capacity moved into the Midwest. On top of all this, the trunkline system must also replace declining domestic production sources with imported crude oil from the Gulf Coast. Altogether, the crude oil supply trunklines to the Midwest are facing a growth in supply requirements that is two to three times the traditional growth rate. While throughput expansions are possible to satisfy demand beyond 1977, pipeline companies are somewhat reluctant to invest in major new facilities until plans for long-term supply of crude oil to the Northern Tier are more clearly seen.

Should Michigan refiners be faced with crude shortages, some additional energy could be supplied through the product pipeline systems into that state. These product lines follow paths similar to those for the crude system (see Figure 3-9). Such a shift in supply pattern can, however, create major problems since Michigan refineries would run at reduced throughput. This would adversely affect the economy of refining areas and the state of Michigan in general.

From available information, it is estimated that spare capacity of about 100 MB/CD is available for shipment of products into various parts of lower Michigan. Should this capacity be used for short-term solution to the Canadian crude curtailment problem, the products shipped would be gasolines and distillates. Very little residual fuel is shipped via pipeline.

3.2.2.2 Wisconsin, Minnesota, Eastern North Dakota, and Northern Michigan Pipelines

This very large area within the Northern Tier is currently isolated from crude lines that are capable of transporting crude oil from the Gulf Coast or other areas of the U.S. The refining industry within this broad section has been developed for the processing of crude oil from Canada, North Dakota, and eastern Montana. The crude oil pipelines that do exist within this area reflect this orientation.

As previously shown in Figures 3-10 through 3-13, the Lakehead pipeline enters this Northern Tier area at the northwestern corner of North Dakota and transports Canadian crude oil across Minnesota, via Clearbrook, to refining centers at Wrenshall, Minnesota (near Duluth) and at Superior, Wisconsin. At Clearbrook, the Minnesota crude oil pipeline intersects with the Lakehead system (and the Portal pipeline system) to ship crude oil to refineries in the Minneapolis-St. Paul area of Minnesota. The Lakehead system splits in the Duluth/Superior area and carries crude on either side of Lake Michigan. There are, however, no other refineries in this section of the Northern Tier. The Portal pipeline system (which actually begins in extreme eastern Montana production areas) traverses the state of North Dakota and enters this area of the Northern Tier at Grand Forks, North Dakota. This line continues to connect with the Lakehead system at Clearbrook, Minnesota, and is the supply line to Minnesota for North Dakota and Montana crude oils. Canadian imports also enter this system at the Tioga and Minot area of North Dakota.

The Canadian curtailment has the potential for drastic effects on this section of the Northern Tier. Without Canadian imports, the only existing crude pipeline into this area is from diminishing supplies in North Dakota and Montana. The possibility does exist to reverse the Wascana pipeline to deliver crude into the Interprovincial and Portal pipelines. The only acceptable crude source, however, is sweet Wyoming, which presently moves east to the Chicago area.

Limited supplies of crude oil to replace Canadian supplies can be moved into this area only via the Williams Product Pipeline (which can include batches of crude with its product) or by other means of transportation.

The Williams pipeline has announced plans to expand its capability to ship crude into Minnesota. Crude batches from the Gulf Coast area can be transported via existing crude pipelines to the southern end of the Williams system in Cushing, Oklahoma or Humboldt, Kansas. This is a multi-stage expansion with the initial increment of 80 MB/CD expected to be operational by September or October of 1977. Williams is underwriting this venture with no guarantees from shippers. In contrast to previous space-available arrangements for shipping crude on product lines, this expansion will be dedicated to crude service. The Williams expansion will have little (10 MB/CD) effect on the Superior/Duluth area.

Product pipelines in the Wisconsin, Minnesota, eastern North Dakota, and northern Michigan area were previously shown in Figures 3-15 through 3-18. The Amoco refinery at Mandan (near Bismarck, North Dakota) manufactures products which are shipped via the Amoco pipeline east into Minnesota and down through Minneapolis on the Amoco pipeline. The Amoco line is also fed from the south through Dubuque from the Kansas City and Chicago area refineries. As the crude runs at Mandan reduce due to declining availability of North Dakota crude into Mandan, Amoco is able to move more product up from the Chicago and Kansas areas to pick up the slack.

Another product pipeline into the North Dakota, Minnesota, Wisconsin area is the Williams Pipeline system which, as mentioned earlier, may be able to supply crude along with product in late 1977. This system currently carries product from Oklahoma and Kansas City up through Des Moines into Minneapolis and up to Grand Forks, North Dakota. The Williams system also carries product to Minneapolis from the Duluth/Superior area and into Wassau, Wisconsin. A southern link from Des Moines runs to Chicago. The Badger pipeline originates in the Chicago area and delivers product up into the Madison, Wisconsin area. The West Short Pipeline carries product from Chicago up through Milwaukee into the Green Bay area. The Kaneb pipeline which operates through the Kansas, Nebraska, South Dakota area, carries product into Jameston, North Dakota, and has a modest amount of surplus capacity at this point.

The product pipeline system in total--to at least Minnesota and Wisconsin--can supply small extra quantities of product to alleviate short-term shortages. However, this approach to the shortage problem--if carried across a longer term--will reduce market shares for refiners in this Northern Tier area and cause refining capability to be exported to Chicago and other points in the Midwest. This lost refining capacity is non-recoverable and increases U.S. dependence on foreign products. This aspect is described in detail in Volume II of this study.

It is, of course, clear that pipelines cannot solve the supply problem which will be caused by curtailment of Canadian crude. For tne latter half of 1976 and at least the first nine months of 1977, the replacement of Canadian crude oil and satisfaction of growing demand will require other means of transportation such as barges up the Mississippi and possibly rail shipment of crude oil from the West Coast--at least as far as Minot, North Dakota.

#### 3.2.2.3 Western North Dakota, Montana, and Eastern Washington Pipelines

This very large Northern Tier area has only one existing pipeline (from Wyoming) which can ship crude oil into its refining centers except for those from Canada. The crude oil pipeline systems previously shown in Figures 3-12 and 3-13 for North Dakota and Montana are mainly geared to the importation of Canadian crude and its distribution to refining centers in the Billings and Cut Bank areas of Montana and to the refining centers near the Montana-North Dakota border. Although half the crude refined in these areas is indigenous crude, substantial amounts of the crude produced in Montana and North Dakota are shipped out of this area for refining elsewhere. The Billings refiners cannot receive this crude via existing pipelines.

Curtailment of crude exports from Montana in the short term could, however, become involved with contractual and ownership problems and is an unlikely overall solution to the crude oil shortfall problem.

Some Wyoming crude could possibly be shipped into Montana, but Montana refiners are strictly limited as to the amount of heavy Wyoming crude they can process because of the high asphalt yield. Northwestern Wyoming crude is currently moving into Billings via the Exxon pipeline. Some of the excess asphalt and residue have been shipped by rail from Billings to other marketing areas; storage in the external markets, however, is nearing capacity. Increased processing of heavy Wyoming crude in Billings will further compound the problem of disposing of asphalt and residue.

Product pipelines, shown in Figures 3-12 through 3-14, are mainly a system for distributing product within this Northern Tier area. Exceptions are the Continental product pipeline which ships product out of Billings into Wyoming, the Chevron product pipeline which ships product into the Pasco and Spokane areas from Salt Lake City, Utah, and the small Husky pipeline which brings products into Billings from Wyoming. The major product pipelines internal to this general area are the Yellowstone product pipeline transporting products from Billings, Montana, into eastern Washington--including Larson Air Force Base--and a Cenex pipeline transporting product from Billings to North Dakota. Chevron reports that it has received product shipments via barge up the Columbia River to Pasco, Washington, for pipeline shipment on into the state, which could open the possibility for supplying the eastern side of Washington, at least to some extent, with products from the Puget Sound refining areas. Current information indicates, however, that this pipeline is running at capacity.

Of the existing product system, the only means for supplying additional product into this Northern Tier area would be by the Chevron pipeline from Utah. Even if this is possible, however, this would export refining from the Northern Tier area to other areas of the United States as discussed in paragraph 3.2.2.2. There is also a question as to whether refineries in Salt Lake City have either available capacity or crude oil to support this possibility.

Indirect product supply to Montana could be by supply to Denver via the Chase pipeline. The product being shipped from Casper to Denver would then cease, as would product shipments from Billings to Casper. The Billings refiners could, therefore, keep more product within Montana.

*In the short term, pipelines alone cannot solve the problem of replacing Canadian crude oil in this area of the Northern Tier.* Replacement crude in the short term will apparently have to be moved into the refining centers of Montana and North Dakota by rail. No serious problems are foreseen for 1976 and 1977, however, while Canadian crude oil imports remain relatively high. Beyond 1977, until permanent supplies can be arranged by other means or until exchanges can be effected, rail transportation of crude appears to be the only answer to crude shortfall if it can be made environmentally acceptable.

### 3.2.2.4 Western Washington Pipelines

Western Washington has only the TransMountain crude oil line from Canada, as previously shown in Figure 3-14. The main product line is the Olympic, which connects to the Southern Pacific pipeline at Portland, Oregon for deliveries south into Eugene, Oregon. Product pipeline capabilities for Washington are illustrated in Figure 3-20.

The existing pipeline systems are not a viable alternative for supply of additional crude required for this area in late 1976 and 1977. Puget Sound refining centers should be able to obtain an adequate supply of crude via tanker shipments if Washington State permits. There are some dockage limitations for some of the refiners, but these are expected to be surmountable.

### 3.2.2.5 Expansion Capabilities of Pipelines

Frequently, when new pipelines are being installed, a larger diameter and greater wall thickness than are needed for immediate throughput requirements will be chosen. Of course, this adds to the cost of the initial installation, and the extent to which oversizing is chosen depends among other things on long-range projections, company policy, availability of capital, and alternative capital ventures.

As markets develop and additional shippers tie-in to the system, the pipeline company has considerable flexibility in expanding throughput and other capabilities to provide the needed services. They can, subject to favorable economics:

1) Add horsepower at existing stations up to pressure limits of the line pipe, physical space limits in the facility, availability of power, etc.

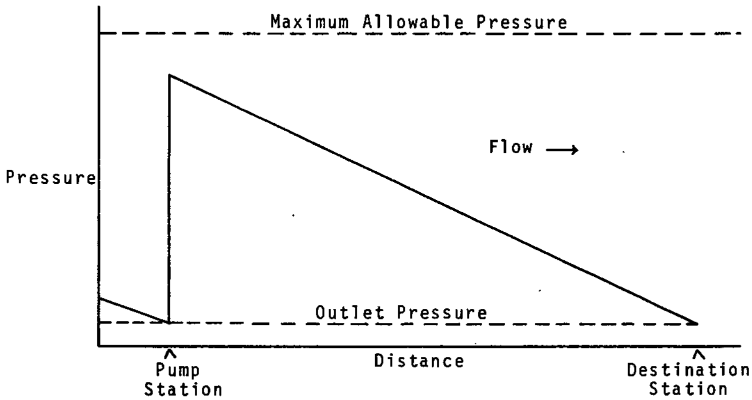
2) Fill-in longer segments of the line with additional pump stations subject to permits, environmental restrictions, availability of materials, etc.

3) Add parallel loops of pipe over various parts of the system, again subject to the previous limitations.

4) Add tankage facilities to allow segregation of different grades of material and to provide more flexibility in batch size.

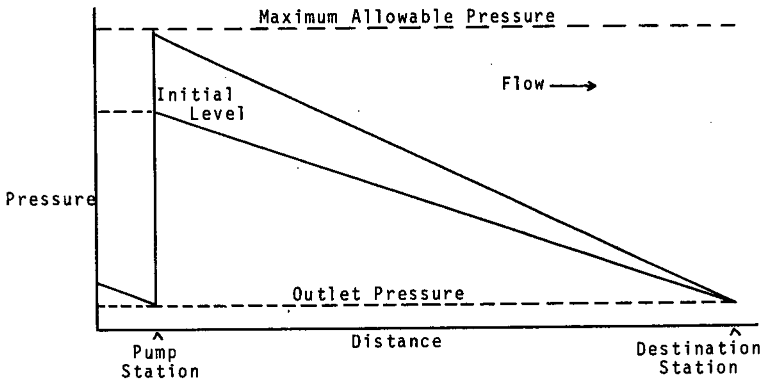
5) Add facilities to transfer to other pipelines and to barge, rail, and truck transportation.

The following illustrations present a fundamental picture of the effects of the various options for pipeline throughput expansion.



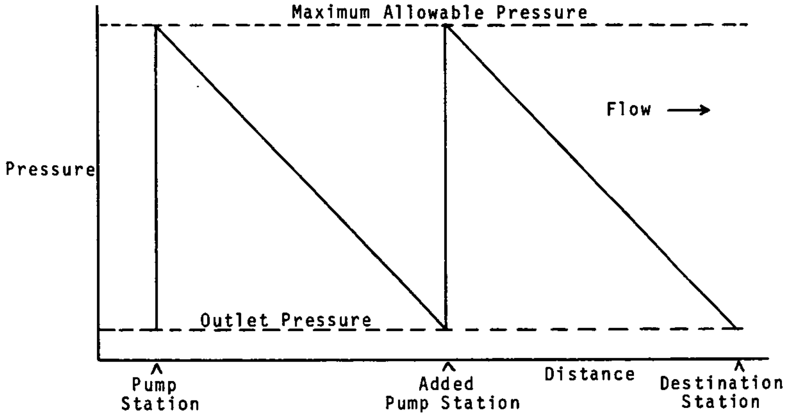

The above illustration shows the pressure graph for the initial installation of the pipeline system. A pump station and a destination station along the route are shown. The horsepower at the pump station is chosen to meet initial throughput requirements. Since the pipeline was oversized initially, however, the pressure boost from the horsepower at the pump station is less than the maximum allowable pressure for the line pipe.

Due to the friction of the material moving through the pipe, the pressure drops over the distance between the stations. The slope of the pressure drop line is a function of the velocity of the flow in the pipe. The slope of the pressure curve arriving at the destination station is an indication of the throughput volume, a more vertical slope corresponding to greater throughput.



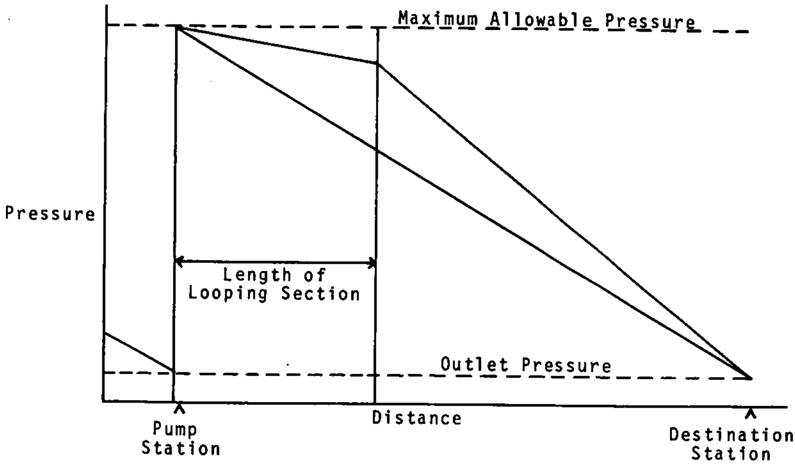

The above illustration shows the effect of adding horsepower at the pump station. The initial pressure boost is greater giving a greater flow rate, but with a corresponding increase in moving friction--hence a greater pressure drop over the distance. The increased flow is indicated by a steeper slope of the pressure curve arriving at the destination station.

Lead time to install additional horsepower usually varies from 6 to 12 months with a typical figure of around 10 months.




The above illustration shows the effect of adding a pump station between the original pump station and the destination station. The focal point of this picture is the slope of the pressure curve into the destination station. The slope is now considerably greater as a result of adding the intermediate pump station. This indicates a greater throughput to the destination station.

Lead time to install additional pump stations usually varies from 12 to 18 months with a typical figure of around 16 months. Arrangements to get power to the station can sometimes be a significant problem.




The above illustration shows the effect of adding a short section of parallel pipe on the high-pressure side of a pump station. Since the effective pipe diameter is greater, the velocity is reduced and gives a lower pressure drop due to frictional loss over the looped portion of the pipeline. This results with a steeper pressure curve, i.e., more throughput, at the destination station.

Lead time to install loops in a pipeline system involves considerable construction and usually varies from 18 to 30 months with a typical figure of 20 months. Right-of-Way and permit problems can introduce significant delays in completion of looping projects.

### 3.2.2.6 Batching Crude Oil in Product Pipelines

Traditionally, product pipelines and crude oil pipelines have been entirely separate entities. There have been logistical and operational bases for this distinction.

In a logistical sense, crude oil pipelines connect remote oil fields to refining centers, and product pipelines connect refining centers to more local market areas. The market areas are usually removed from the oil fields, so in most instances the consideration of dual pipeline service is useless. Crude oil trunklines are long-distance, large-volume lines typically 12-30 inches in diameter. Product mainlines tend to be shorter distance radians distributing smaller volumes over a wide area and are typically 6-12 inches in diameter. As the industry has developed, refining centers have become interconnected with crude lines and product line radians have extended to interconnect market areas providing crude and product pipeline networks with considerable flexibility to adjust for varying needs and to provide back-up and reliability over-all.

Economy of scale and availability of crude oil among other considerations have created a few noteworthy anomalies in the product pipeline situation. Colonial and Plantation pipelines are 36 and 30 inches in diameter, respectively, and carry products from the Gulf Coast into the East and Northeast. Explorer is a 28-inch diameter line from the Gulf Coast to Oklahoma and a 24-inch diameter line continuing north to Chicago. The Williams system has dual 12-inch lines among others which extend from Oklahoma north through Minnesota.

With Explorer and Williams having the proper logistics to alleviate some of the problem created by the reduction of Canadian crude exports, a number of operational problems need to be overcome in order for these product lines to carry crude. (As an aside comment, the existing crude oil system does have capacity sufficient to meet normal market growth over the next few years with the capability to provide further orderly expansion as needed; the relative abruptness and magnitude of the crude curtailment, however, will strain these facilities close to limits.) The operational problems are principally product contamination, segregated tankage for crude oil, and pumping horsepower necessary to move the more viscous crude oil. Secondary, but still significant, problems are the increased complexity of batch scheduling (possibly leading to conflicts which reduce overall throughput) and line corrosion resulting from agents in the crude oil.

The problem of contamination has largely been met by requiring number 2 fuel oil buffers leading and following the crude batch. The total buffer volume is about 20 MB, of which 6 to 8 MB are contaminated and must be taken with the crude for re-refining.

Chemical additives provide some of the technological solution to the problem of batching crude with products. Small amounts of inhibitors have been effective in controlling corrosion. Similarly, pour-point depressants have been effective in reducing the viscosity of the crude oil and improving the pumping characteristics.

Improved batch scheduling and sequencing can also relieve the pumping problems. Product deliveries prior to the end of the line slow the velocity from the point of delivery on to the end of the line so horsepower in the slower segment is usually reduced. If the volume in the slower segment happens to be crude oil, full pumping power may be able to keep the overall throughput of the line at desirable rates. Crude oil volumes may not exceed 50 percent of the total throughput of the line. The scheduling cycle can run 10 days in advance of current operations. Weather changes and inventory levels can have overriding effect on established schedules. Considerations such as these further confound the already complex job of scheduling multiple product batches to the market areas where they are needed.

Explorer and Williams have expressed confidence that the problems of handling crude oil and products in the same pipeline can be greatly overcome and are continuing to pursue that goal.

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### 3.2.3 Unit Train Transport of Petroleum

The railroads are not an important factor in the movement of petroleum because of their high cost relative to other modes of transportation. Table 2 illustrates the insignificant portion of petroleum moved by railroads.

Recently, design improvements have been made to liquid tank cars to increase the efficiency of load and unload operations. General American Transportation Corporation (GATX) has pioneered the unit train concept, which uses 90 tank cars of the interconnecting type shown in Figure 3-21. The interconnections allow strings of cars to be loaded or unloaded at one time, thereby decreasing the cost of this otherwise labor-intensive operation. Use of interconnecting cars also reduces the occurrence of oil spills and facilitates the collection of air-polluting vapors. The cars are heavily insulated and can retain adequate temperatures on heated liquids such as residual fuel even in the coldest Northern Tier winter.

#### 3.2.3.1 The Burlington Northern/GATX Proposal

The Burlington Northern Railroad, in collaboration with GATX, is proposing to assemble unit trains for hauling crude from the Washington/Oregon Coast eastward to Northern Tier refiners. They plan to load Alaskan crude when it becomes available and other offshore foreign crudes at Port Westward, Oregon, 65 miles from the mouth of the Columbia River. This facility is used by the U.S. Army for Far Eastern supply and requires only minor modification for unit train loading. It can dock 35,000 DWT tankers and lighters with a maximum throughput capacity of 300 MB/CD. Alternate facilities in the Puget Sound area, which can handle up to 125,000 DWT tankers, are being investigated.

## TABLE 2

## TOTAL CRUDE PETROLEUM CARRIED IN DOMESTIC TRANSPORTATION AND PERCENT OF TOTAL CARRIED BY EACH MODE OF TRANSPORTATION[1]

| YEAR | TOTAL CRUDE PETROLEUM CARRIED (MILLION TONS) | PIPELINES PERCENT OF TOTAL | WATER CARRIERS PERCENT OF TOTAL | MOTOR CARRIERS PERCENT OF TOTAL | R. R.'s PERCENT OF TOTAL |
|---|---|---|---|---|---|
| 1938 | 180.5 | 71.01 | 25.58 | 1.17 | 2.24 |
| 1943 | 240.7 | 73.46 | 12.93 | 3.27 | 10.34 |
| 1948 | 322.9 | 68.48 | 23.26 | 3.86 | 4.40 |
| 1953 | 376.8 | 75.19 | 18.73 | 5.05 | 1.03 |
| 1958 | 402.1 | 76.35 | 16.90 | 6.45 | 0.30 |
| 1963 | 468.0 | 75.17 | 17.78 | 6.88 | 0.17 |
| 1968 | 547.8 | 74.08 | 18.62 | 7.11 | 0.19 |
| 1969 | 592.9 | 74.41 | 18.50 | 6.93 | 0.16 |
| 1970 | 615.2 | 74.30 | 18.90 | 6.65 | 0.15 |
| 1971 | 616.2 | 74.62 | 18.62 | 6.62 | 0.14 |
| 1972 | 643.7 | 75.75 | 16.10 | 7.92 | 0.23 |

[1]"Unit Train Transport of Alaskan Oil from the West Coast to the Midwest," Arthur M. Hughes, Chief, Division of Coal Economics and Transportation, Office of Coal, Federal Energy Administration, 2 July 1976.

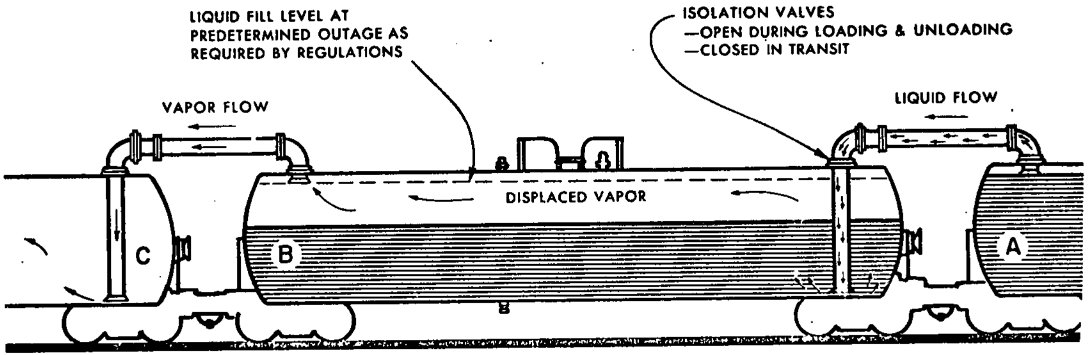


Figure 3-21. Basic Flow Diagram During Loading Phase
Interconnected Tank Cars

The unit trains would head eastward over Burlington Northern tracks and unload at Cut Bank, Montana and Tioga or Minot, North Dakota.

At Cut Bank the trains would unload directly into the Glacier pipeline (owned by Conoco) to supply the Billings, Montana refineries. At Tioga, the trains would unload into the Amoco pipeline to supply the Amoco refinery at Mandan. After unloading at either Tioga or Minot into the Portal pipeline, the crude would flow into the Lakehead pipeline at Clearbrook, Minnesota to supply any refineries on that entire system.

*A major attraction of this plan is that it can be operational (initially with small volumes) in six to nine months.* Unloading facilities at Cut Bank and Tioga or Minot can be completed in six months. GATX has manufacturing capacity for up to 2,000 interconnecting cars per year and can produce more with subcontractors. Initial deliveries of completed cars can begin as soon as six months after contracts are signed. The route between Port Westward and Minot is mostly along Burlington Northern's main line and would not, therefore, require any significant upgrading. A short 10-mile spur from Bagley to Clearbrook, Minnesota, plus unloading facilities at Clearbrook could be built in this short time frame.

3.2.3.2 Costs for Unit Trains

Since common carrier tariffs for crude have not been established over the Burlington Northern route, estimates must be made using historical cost data. Table 3, "Unit Train Statistics and Assumptions", was compiled from discussions with

TABLE 3

UNIT TRAIN STATISTICS AND ASSUMPTIONS

A) Capacity - 551 bbls/car, 49,600 bbls/train
- 82.7 tons/car, 7,440 tons/train
- 20 M.P.H. haul rate
- 10.8 MBPD/90 car train to Cut Bank
- 7.9 MBPD/90 car train to Minot

B) Variable Costs - Energy (90 cars), maintenance, locomotives (5) caboose, margin
- No backhaul
- No switching (single railroad)

$0.0115/ton-mile, $0.0017/bbl-mile for mountainous terrain

$0.0092/ton-mile, $0.0014/bbl-mile for flat terrain

C) Car Ownership Costs - 10 year depreciation
- $45,300/car, $478/month on 12 year lease
- 10% spares for down-time

$0.001/ton-mile, $0.00015/bbl-mile

D) Running Gear Costs - Change running gear periodically

$0.0007/ton-mile, $0.0001/bbl-mile

E) Loading/Unloading Costs - Port Westward, Oregon $0.15/bbl
- Into/out of any pipeline $0.10/bbl
- Time for 5-18 car strings, 3 hr. 15 min.

F) Backhaul - Could reduce variable costs of front haul 20-40% depending on volume.

G) Distances Along Burlington Northern System -

| | |
|---|---|
| - Port Westward, Oregon to Cut Bank, Montana | 805 miles |
| - Cut Bank to Tioga, North Dakota | 482 miles |
| - Tioga to Minot, North Dakota | 81 miles |
| - Minot to Bagley, Minnesota | 345 miles |
| - Bagley to Clearbrook, Minnesota | 10 miles |
| | 1,723 miles |

representatives of Burlington Northern and the Federal Energy Administration's Office of Coal. The factors for variable, loading/unloading, and running gear costs are approximations subject to some degree of error. It is believed, however, that the factors are satisfactory for making estimates of unit train costs within ±25 percent.

Table 4 presents transportation cost estimates for the Burlington Northern/GATX Proposal. It shows that the per-barrel costs are quite high when compared to pipeline movement. Consequently, the Burlington Northern/GATX proposal represents a feasible but high-cost way of meeting short-term crude shortfalls in the two states.

### 3.2.3.3 Backhaul Possibilities

The cost estimates in Table 4 are conservative because no cost reductions from backhauling other liquids were considered. Burlington Northern believes there are backhaul possibilities which could lower the crude movement costs (variable portion) by 20 to 40 percent. Two product backhauls are being considered--residual fuel (No.6) and a mixture of coal particles and residual fuel dubbed "Coaleum"[1] by Burlington Northern. Residual fuel will be in surplus in Montana and North Dakota once heavier crudes are run. The market for these products appears to be Puget Sound power plants and pulp and paper mills, many of which now burn Canadian gas as boiler fuel. If the residual fuel were unloaded

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[1] A mixture of pearl-sized, dried particles (approximately 11,000 Btu's/ton) in suspension in residual fuel which can be pumped and transported at 135-145°F.

## TABLE 4

## TRANSPORTATION COST ESTIMATES FOR BURLINGTON NORTHERN/GATX PROPOSAL

| $/bbl | Cut Bank, Montana | Billings, Montana | Minot, North Dakota | Mandan,[2] North Dakota | Clearbrook,[3] Minnesota | Minneapolis, Minnesota | Superior, Wisconsin | Marysville, Michigan |
|---|---|---|---|---|---|---|---|---|
| Load (Port Westward)[1] | 0.15 | | | | | | | |
| Variable | 1.45 | 1.45 | 1.95 | 1.93 | 1.95 | | | |
| Car Ownership | 0.15 | 0.15 | 0.21 | 0.20 | 0.21 | | | |
| Running Gear | 0.08 | 0.08 | 0.14 | 0.13 | 0.14 | | | |
| Unload | 0.10 | | | | | | | |
| Pipeline | --- | Glacier 0.30 | --- | Amoco 0.11 | Portal[4] 0.35 | Minnesota 0.52 | Lakehead 0.41 | Lakehead 0.57 |
| TOTAL without Backhaul | 1.93 | 2.23 | 2.55 | 2.62 | 2.90 | 3.07 | 2.96 | 3.12 |
| TOTAL with Backhaul (30% credit on variable cost) | 1.50 | 1.80 | 1.97 | 2.04 | 2.32 | 2.49 | 2.38 | 2.54 |

[1] 35 DWT Tankers. Does not include cost of lightering larger tankers.
[2] Unload at Tioga.
[3] Unload at Minot.
[4] Portal will reduce existing $0.55/Bbl tariff.

at the same point that the crude was loaded, the current $4.00/Bbl cost of moving residual fuel to the West Coast would be reduced to $2.50/Bbl.

Backhaul credits would make the unit train concept more attractive as a short-term supply alternative.

### 3.2.3.4 Environmental Considerations

The environmental impact of unit trains from Oregon to Montana has not been studied. In addition to potential oil spills in the Oregon offloading area, negative environmental impacts from spills could appear during the train loading/ unloading operations and in the case of a derailment.

The interconnecting concept of these trains should reduce spills during loading and unloading, and the cars will also be equipped with universal joint couplings. These couplings are more expensive than the standard types on older tank cars. Their value is that if a derailment occurs causing the cars to twist relative to one another, the cars will remain coupled. The probability of one car puncturing another is, therefore, reduced.

### 3.2.4 Barge Transport on the Mississippi River

The refiners in the Minneapolis-St. Paul area are considering shipping crude in barges up the Mississippi River. One of these refiners is already shipping small amounts of crude this way.

The shipment begins by offloading tankers between New Orleans and Baton Rouge into a "tow" of one small and three large barges which can carry 23,000 DWT. At average crude gravities, approximately 150,000 barrels can be carried in one tow. The tows are designed to fit through 27 locks north of St. Louis with dimensions of 600 feet by 100 feet. The barges travel the 1659 running miles (1759 billing miles) in about 10 days, although delays at certain of the locks could extend the time as discussed later. On the average, barges can travel about 165 miles per day, and can offload directly at refinery docks. Current dock facilities may not be adequate to handle increased rates of barge offloading, however, and storage facilities are not adequate to store enough crude for the four winter months when the river ices over. Expansion of existing dock facilities could involve as many as 24-30 months.

Barges transporting crude in this way are not considered common carriers subject to I.C.C. tariff approval. Individual contracts are written between the shippers and the barge owners, and can be negotiated by trip, for short periods of a month or a year, or for long periods of three to five years. In the latter case, cost escalators for labor and fuel are typically built into the contract.

### 3.2.4.1 Costs for Barge Transport

According to the barge companies interviewed, estimated costs are in the range of $1.05 to $1.40 per barrel from the Louisiana coast to Minneapolis, including loading and unloading but not cargo insurance. Heavier crudes would be at the high end of the range, whereas light crudes would be at the low end.

Barging crude to the St. Louis/Wood River area and then pipelining it to Eastern Michigan is also feasible, given that spare pipeline capacity exists. Only two locks have to be used. Costs for this movement are estimated to be $0.75-1.00 per barrel for the barge transport plus $0.32 per barrel for the pipeline to Marysville, Michigan via Marathon, Chicap and Lakehead pipelines.

These barge transport costs are obviously quite competitive with pipeline costs, particularly into the Minneapolis area.

These cost estimates only apply to barge movements below 100 MB/D or 15 tons, however, because there appears to be sufficient spare barge capacity on the Mississippi River to handle up to that rate. Above that rate, new barges would probably have to be constructed. In such a "tight" barge supply market, higher rates than the $1.40 into Minneapolis will certainly be quoted.

3.2.4.2 Navigational Problems

The major drawback to using barge transport as the primary source of crude supply to Minneapolis is winter ice on the upper Mississippi River. During normal years, barge transport is reliable for the eight months between March 15th and November 15th. Although the navigation season may be longer by a few weeks in mild years, refineries in the Minneapolis area must obtain winter crude supplies from other sources because tankage is insufficient to handle four months of crude inventory.

The navigation season is longer to St. Louis/Wood River. Typically, shipments can be made 12 months of the year.

Another problem is that delays occur entering the many locks north of St. Louis. Although average delays are predictable and have been built into the estimated costs discussed earlier, one particular lock, Number 26, has been the Number 26 is presently being repaired by the Corps of Engineers, and such delays should be significantly lessened. Cost of barge transport to Minneapolis could be improved if all the locks were in top condition.

3.2.4.3 Environmental Considerations

The environmental impact of this increased barge activity on the Mississippi River has not been studied. Permits must be obtained, and it is anticipated that environmental groups opposed to expanded river traffic will continue their opposition.

# SECTION 4

# ANALYSIS

This section presents the analysis derived from examining the refineries and utilities, transportation networks, and production systems described in Section 3 and in Addenda A through C.

Also described are the procedures used and the results obtained in analyzing the effect of decreased Canadian crude on product prices during 1976 and 1977.

## 4.1 REFINERY ANALYSIS

This refinery analysis is based on visits to fourteen facilities and telephone conversations with the eleven other Priority 1 or 2 facilities of the Northern Tier. Because some refiners would not provide all of the data requested, the affidavits submitted for the initial Priority 1 or 2 request were used extensively for this analysis. This refining result is Bonner & Moore's best judgment of the composite of information received and assumptions made at this time.

### 4.1.1 Historical and Projected Crude Usage

The Priority 1 and Priority 2 Northern Tier refiners and utilities processed approximately 844 MB/CD of crude and crude substitutes during the first half of 1976--composed of approximately 113 MB/CD of crude from within the Northern Tier States, 24 MB/CD from other Northern Tier States, 113 MB/CD from other domestic fields, approximately 379 MB/CD of crude by allocation from Canada, 12 MB/CD of Canadian crude by exchange within their own companies, and approximately 203 MB/CD of other foreign crudes.

The Northern Tier refiners expect to process 837 MB/CD of crude during the second half of 1976. The 44 MB/CD decrease in allocated Canadian crude will be replaced by 34 MB/CD of foreign imports to the Washington area, 3 MB/CD of foreign imports to Michigan, and include 7 MB/CD of decreased refinery runs. These refiners expect to process about 844 MB/CD of crude in 1977. The 85 MB/CD decrease of Canadian crude by allocation between the latter half of 1976 and 1977 will be replaced on a yearly average basis by about 76 MB/CD of Alaskan North Slope crude, 15 MB/CD of exchanges with Canada, and a net decrease of 6 MB/CD of other crude supplies.

These balances are summarized by market area in Table 5.

The key assumptions for 1977 are:

1) That Alaskan North Slope crude will be available to Washington refineries in mid-1977. For the yearly average basis, this represents 76 MB/CD of North Slope crude being processed in the Washington refineries. Until this Alaskan North Slope crude is available, these refiners expect to be able to import sufficient quantities of acceptable foreign crude.

## TABLE 5

## NORTHERN TIER CRUDE OIL BALANCE

## BY MARKET AREA

| | | DOMESTIC | | | FOREIGN | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Interstate | | Canadian | | | | | |
| | Throughput[1] | Intrastate | Other Northern Tier | Other Domestic | By Allocation | By Exchange[2] | Other Foreign | Total Supply[3] | Crude Deficiency[4] | Spare Refining Capacity[5] |
| FIRST HALF 1976 | | | | | | | | | | |
| Michigan | 177.8 | 53.4 | ..... | 45.5 | 58.7 | ..... | 20.2 | 177.8 | 0 | 21.1 |
| Wisconsin/Minnesota/East North Dakota | 247.8 | 36.2 | 24.0 | 11.2 | 170.3 | 6.1 | ..... | 247.8 | 0 | 63.4 |
| West North Dakota/Montana/East Washington | 128.0 | 23.7 | ..... | 44.0 | 58.7 | 1.6 | ..... | 128.0 | 0 | 26.5 |
| West Washington | 290.7 | ..... | ..... | 12.0 | 91.7 | 4.5 | 182.5 | 290.7 | 0 | 45.8 |
| Total Northern Tier | 844.3 | 113.3 | 24.0 | 112.7 | 379.4 | 12.2 | 202.7 | 844.3 | 0 | 156.8 |
| SECOND HALF 1976 | | | | | | | | | | |
| Michigan | 177.1 | 54.7 | ..... | 45.7 | 50.1 | ..... | 23.6 | 174.1 | 3.0 | 22.3 |
| Wisconsin/Minnesota/East North Dakota | 245.4 | 36.2 | 21.3 | 11.6 | 168.3 | 8.0 | ..... | 245.4 | 0 | 65.8 |
| West North Dakota/Montana/East Washington | 127.6 | 23.4 | ..... | 45.7 | 58.1 | 0.4 | ..... | 127.6 | 0 | 26.8 |
| West Washington | 287.0 | ..... | ..... | 12.0 | 58.8 | 2.9 | 213.3 | 287.0 | 0 | 49.5 |
| Total Northern Tier | 837.1 | 114.3 | 21.3 | 115.0 | 335.3 | 11.3 | 236.9 | 834.1 | 3.0 | 164.4 |
| 1977 | | | | | | | | | | |
| Michigan | 187.4 | 53.0 | ..... | 44.7 | 39.1 | ..... | 29.8 | 166.6 | 20.8 | 22.6 |
| Wisconsin/Minnesota/East North Dakota | 245.3 | 34.0 | 23.5 | 15.3 | 157.1 | 3.1 | ..... | 233.0 | 12.3 | 66.0 |
| West North Dakota/Montana/East Washington | 126.6 | 22.4 | ..... | 48.4 | 54.7 | (3.0) | ..... | 122.5 | 4.1 | 27.8 |
| West Washington | 285.0 | ..... | ..... | 88.0 | 0 | 15.0 | 182.0 | 285.0 | 0 | 51.5 |
| Total Northern Tier | 844.3 | 109.4 | 23.5 | 196.4 | 250.9 | 15.1 | 211.8 | 807.1 | 37.2 | 167.9 |

1 Refiners' estimates of expected throughput.

2 These exchanges are within the same company, with majors, or with the Canadians.

3 Refiners' estimates of expected supply.

4 Crude deficiency refiners plan to find a means of making up.

5 Average capacity that could reasonably be available, if needed or if economically attractive.

2) That 15 MB/CD of crude will be exchanged with the Canadians, by effective replacement with foreign crude. This key point is discussed below.

3) That the buy/sell, allocation, and entitlement programs all remain essentially as they are at this time.

4) That the crude pipelines are able to deliver about the same amount of foreign crude as they have been delivering in the third quarter of 1976.

The discussion in this section concentrates on refiners rather than refiners plus utilities because refiners represent about 782 MB/CD of the 844 MB/CD of crude throughput for the first half of 1976. Of the 62 MB/CD processed by utilities, only 41 MB/CD was covered by the Canadian allocation program, and all but 27 MB/CD of the 41 MB/CD will be replaced with Canadian residual fuel oil by the end of 1977. The 27 MB/CD that will not be replaced is Canadian condensate processed by Consumers Power's Marysville SNG plant, which is planning to increase their runs in 1977 by 25 percent of their total 1976 runs. An overall naphtha balance for the Michigan area should be made to determine if this plant has any alternative other than the Canadian condensate. The remainder of this introduction deals primarily with the refiners of the Northern Tier and include the utilities in the total balances.

From the Northern Tier refiners' viewpoint, crude exchanges represent their most economical short-term alternative. For the purposes of this analysis, crude exchanges refer to arrangements made between two refiners, not producers--and these refiners are either both U.S. or one U.S. and one Canadian. Crude exchanges are detailed in Volume II of this study.

There appears to be room for free market competition to set a balance between (1) American refiners that have access to light, low-sulfur crude and that can receive and process foreign crude, and (2) American refiners that do not have access to light, low-sulfur crude and that do not have the ability to receive and/or process foreign crude. This is a very sensitive area of analysis. The reason for the market-place emphasis is straightforward. Crude prices (with inherent adjustments for transportation and sulfur) set the balance between the refiner who is limited in his ability to process heavy-high-sulfur crude and the refiner who can access and process heavy, high-sulfur crudes.

For example, there is some crude in Wyoming that could be processed by the refiners in Montana. This crude is presently being moved eastward and being processed in refineries that have some degree of capability to receive foreign crude. In theory, the Glacier and other pipelines could be reversed, and this Wyoming crude could be moved into Montana. The Montana refiners would then produce petroleum products that would compete in the eastern Washington area with products that are brought in by pipeline from the Utah area. Traditionally, this balance would be achieved through competition and economics.

This example concerning Wyoming is presented as only one of many such alternatives available in the Northern Tier area. All of them are based on the concept of a refiner who can only process light, sweet crude--buying that crude from a refiner who has an option to process heavy, foreign crude--and then putting petroleum products into the marketplace at a price to compete with petroleum products from the second refiner who is processing foreign crude.

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Referring to the overall Norther Tier shown in Table 5, there is 37 MB/CD of crude shortfall shown in the 1977 time period. This shortfall is defined as the difference between the throughput that the Northern Tier refiners expect they are going to be able to run, and the crude supply that they tentatively have committed from suppliers. About 10 MB/CD of that shortfall could be replaced by foreign crude if pipeline space were available to bring it into Michigan. About 11 MB/CD of that shortfall can only be rcplaced by exchanges with Canadians. The remaining 16 MB/CD shortfall is to the SNG plant.

In addition to this shortfall, there is about 167 MB/CD of spare refinery capacity that could be utilized in the Northern Tier. In general, economics have probably dictated about 77 MB/CD of this spare capacity (the other 90 MB/CD represents the historical capacity underutilization) because its utilization would result in the production of petroleum products to compete in an area that is supplied by pipeline from another non-Northern Tier refiner.

The foregoing discussion is based on the refiners' estimated data on throughput and crude supply, as summarized in Table 5. It should be noted that seasonal effects which are significant are not included in this discussion. It also should be noted that analysis of the data presented in Addendum A reveals that the small refiners' livelihood is largely dependent on allocations and some government involvement.

### 4.1.2 Analysis

In order to analyze the Northern Tier, it is desirable to divide the region into four marketing areas. These areas are defined by the refineries' and pipelines' ability to supply products, and there is comparitively little overlap between the areas. Starting from the east and moving west, these areas are the state of Michigan; the states of Wisconsin and Minnesota, and eastern North Dakota; the states of Montana, western North Dakota, and eastern Washington; and western Washington. Each of these areas is discussed below.

The Michigan area contains six refiners and is served by product pipelines from refiners located outside the state. Of a total of 177 MB/CD of expected throughput, the Michigan refiners have a shortfall of 3 MB/CD in the second half of 1976 and 21 MB/CD in 1977. (About 16 MB/CD of this shortfall is for the SNG plant discussed earlier.) These refiners could make up this shortfall by purchasing foreign crude, but at this time they do not have available pipeline space to be able to import such crude into their refineries. While these refineries do not really need exchanges with the Canadians, such exchanges may be very economical for them; refer to Volume II for a complete discussion of crude exchanges with the Canadians.

The Wisconsin, Minnesota, and eastern North Dakota area is serviced by five refineries: one in Wisconsin, three in Minnesota, and one in the middle of North Dakota. Only the North Dakota refiner has not been able to line up enough crude to be able to run at desired throughput for 1977, and the Wisconsin refinery is presently running at half capacity. The Wisconsin, northern Minnesota, and North Dakota refiners see no short-term alternative other than working out exchanges with the Canadians. A portion of crude could conceivably be moved into northeastern Minnesota by reversing the Williams product pipeline, but this is only 10 MB/CD of crude that would be directly available to 69 MB/CD of capacity out of a total refining capacity of 188 MB/CD. The southern Minnesota refineries could conceivably barge a significant volume of crude up the Mississippi during eight months of the year to adjust for the further curtailment of the Canadian crude. Barging on the Mississippi is covered in more detail in subsection 3.2 of this report.

The western North Dakota, Montana, and eastern Washington area is essentially serviced by the seven Montana refineries. The Montana refineries considered in this study process about 127 MB/CD of crude, of which approximately 70 MB/CD comes from the Montana/Wyoming area and 55 MB/CD is imported from Canada. The only alternate crude for the small, northern Montana refineries is Canadian. The refineries in the Billings area could conceivably receive crude from the Wyoming area with the reversal of the Glacier pipeline as discussed earlier, but for all practical purposes their most economical alternative in the short term is probably based on exchanges with the Canadians.

The western Washington area is unique in the Northern Tier. These refineries process about 250 MB/CD of crude, and only about 50 percent of their products are needed to serve the western Washington and western Oregon area. The balance of their products are shipped south by vessel to other parts of the U.S. West Coast. In general, these refineries have the ability to purchase acceptable foreign crude, receive it over their docks, and process it. It is assumed that the 50 MB/CD spare capacity that exists in this area is dictated by economics and supply to the West Coast areas. From an overall economic viewpoint, crude exchanges with the Canadians in this area would save significant transportation dollars.

In summary, most of the Northern Tier refiners expect to be able to process approximately the same amount of crude in 1977 as they did in the first half of 1976. The refiners have tentatively lined up all but 21 MB/CD of crude to meet their desired 1977 runs. (The utilities are short 16 MB/CD primarily for increased throughput.) It should be stressed that the most significant short-term step that can be taken would be for the U.S. Government to expedite the approval of exchanges with the Canadians.

A detailed description of each Priority 1 and Priority 2 Northern Tier facility is presented and summarized by state in Addendum A.

## 4.2 TRANSPORTATION ANALYSIS

Analysis of data gathered with respect to transportation capabilities and possibilities in the Northern Tier states yields the following results:

- Only in lower Michigan can existing pipelines be utilized to fill crude oil and products requirements during the phase-down of Canadian crude imports through 1977. Beyond 1977, both the basic trunklines moving crude oil into the Midwest and pipelines moving crude specifically into Michigan will need added capacity in order to satisfy growing demands in Michigan while replacing Canadian crude and adding foreign crude at the trunkline's southern terminus to make up for diminishing domestic oil production along the trunkline's route.

- There appears to be no pipeline solution for fully making up crude shortfalls in the Wisconsin, Minnesota, eastern North Dakota, and northern Michigan area. During the next 18 months, however, shortfalls can be made up by other means of transportation. Unit trains appear to be an economically feasible way to get crude into Montana, as do shipments of crude via barges up the Mississippi to the Minneapolis/St. Paul area--but both these alternatives must resolve environmental problems. The refining center in the Duluth/Superior area may be able to receive more crude oil from unit trains feeding a pipeline system beginning in western Montana. A proposed Williams pipeline expansion, combined with the batching of crude oil in product shipments, may provide some alleviation of crude oil supply problems by the last half of 1977. This alternative would be aimed principally at shipping crude oil into the Minneapolis-St. Paul area.

- Solution will not be by pipeline alone for the general area comprised of western North Dakota, Montana, and eastern Washington. While some product additions can possibley be made in eastern Washington through a pipeline from Salt Lake City or by bringing product into Denver (and thus freeing the Casper and Billings product markets), the most promising and possibly the only alternative for short-term solution of the crude shortfall problem in this area appears to be via unit train from the West Coast of Oregon.

- While pipelines cannot solve the problem of western Washington crude shortfalls, this area of the Northern Tier can be supplied by ocean-going crude carriers, the state of Washington permitting. Until Alaskan North Slope crude is available to this area, however, it will be dependent on foreign crude oil.

Further details on the results from analysis of transportation capabilities are presented earlier in subsection 3.2.

## 4.3 PRODUCTION

Three of the six Northern Tier States considered in this study produce crude oil--Michigan, Montana, and North Dakota. Because Wyoming has been a traditional supplier of domestic crude to the Northern Tier, this state is also included in the production discussion in this subsection and in Addendum C.

Table 6 shows the production of crude oil in MB/CD and the reserves of crude in thousands of barrels for each of these four states. The data were obtained from the A.P.I.'s report entitled "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the U.S. and Canada as of 31 December 3, 1975".

As shown in Table 6, the reserves and production of the states of Montana, North Dakota, and Wyoming are steadily declining. Only Michigan has shown an increase in both reserves and production and has prospects for potential growth.

Table 7 shows the disposition of each state's crude oil production as a percent of total production. This 1975 information was derived from Bureau of Mines reports; the data are preliminary, and certain assumptions consistent with pipeline movements had to be made since the Bureau of Mine reports combine Michigan and North Dakota production with other states.

Table 8 shows the major producer in each state and his percentage of production.

TABLE 6

RESERVES AND PRODUCTION DATA

| YEAR | MICHIGAN | | MONTANA | | NORTH DAKOTA | | WYOMING | |
|---|---|---|---|---|---|---|---|---|
| | RESERVES (MB) | PRODUCTION (MB/CD) | RESERVES (MB) | PRODUCTION (MB/CD) | RESERVES (MB) | PRODUCTION (MB/CD) | RESERVES (MB) | PRODUCTION (MB/CD) |
| 1970 | 45,615 | 32.0 | 241,529 | 103.8 | 192,377 | 60.3 | 1,017,359 | 424.1 |
| 1971 | 58,765 | 32.6 | 228,185 | 94.8 | 174,011 | 59.3 | 996,985 | 396.4 |
| 1972 | 62,002 | 35.6 | 241,248 | 92.9 | 166,033 | 56.5 | 949,779 | 373.8 |
| 1973 | 72,444 | 39.7 | 219,343 | 94.8 | 179,520 | 55.4 | 916,763 | 378.2 |
| 1974 | 82,299 | 49.6 | 207,389 | 94.7 | 172,794 | 54.0 | 903,360 | 377.4 |
| 1975 | 93,312 | 67.2 | 163,968 | 88.4 | 158,245 | 54.9 | 877,385 | 357.4 |

TABLE 7

DISTRIBUTION OF 1975 CRUDE PRODUCTION

| DESTINATION \ ORIGIN | MICHIGAN | MONTANA | N. DAKOTA | WYOMING |
|---|---|---|---|---|
| Michigan | 65.5% | | | 5.5% |
| Montana | | 32.4% | | 13.7% |
| North Dakota | | 4.3% | 52.6% | |
| Wyoming | | 1.6% | | 32.7% |
| Minnesota/ Wisconsin | | 6.7% | 17.7% | .4% |
| PAD 1 | 15.1% | 2.5% | | |
| Illinois, Indiana, Kentucky, Tennessee, Ohio | 19.4% | 43.6% | 26.8% | 22.6% |
| Utah, Colorado | | 3.4% | | 10.7% |
| Other | | 5.5% | 2.9% | 14.4% |
| TOTAL | 100.0% | 100.0% | 100.0% | 100.0% |

TABLE 8

MAJOR PRODUCERS IN STATES

| STATE | OPERATOR | PERCENT OF 1975 PRODUCTION |
|---|---|---|
| Michigan | Shell Oil Company | 37 |
| Montana | Gary Operating Company | 26 |
| North Dakota | Amerada | 40 |
| Wyoming | Marathon | 12 |

## 4.4 AREA ECONOMIC IMPACT

The curtailment of Canadian crude oil imports is expected to have only minimal impact on Northern Tier petroleum product prices during 1977. Although prices may fluctuate due to other economic factors, the increase in prices attributable solely to the Canadian crude curtailment is expected to range from 0.2 cents to 0.3 cents per gallon of product in 1977. (The impact will be progressively severe, of course, in successive years of the interim period if the phase-down of exports to zero is followed by Canada, as announced. The scope of this study, however, excluded analysis beyond 1977.)

The impact on product prices for 1977 in the Northern Tier was determined by an analytical approach which included:

(1) Identification of changes that will take place in crude/product supply patterns within the Northern Tier as a result of Canadian curtailment of crude oil to 1977 levels from 1976 levels,

(2) Identification of cost effects resulting from changes in the supply pattern,

(3) Quantification of cost effects--expressing them in terms of "added costs" per gallon of petroleum product in the Northern Tier during 1977.

Analysis was conducted on a state-by-state basis rather than by marketing areas since product demand data were available only by state.

### 4.4.1 Identification of Supply Pattern Changes

Changes in the crude/product supply pattern as a result of curtailment at 1977 levels may be expressed as follows:

The loss of Canadian crude due to curtailment of exports to the U.S. will be made up, where possible, with importation of other foreign crudes and, to some extent, through negotiations of domestic-for-Canadian crude exchanges. Even so, however, some refiners will be forced to reduce refinery runs since sufficient crude cannot be made available to some geographical areas within the Northern Tier in 1977. Product demand which cannot be satisfied by this new pattern in crude supply must be met by additional shipments of finished petroleum products into the Northern Tier from refining centers in other states.

4.4.2 Identification of Cost Effects

Cost effects stemming from changes in the supply pattern are somewhat more complex, but may be classified in seven categories, as follows:

(1) Product Inshipment Costs

Lost refinery output (because of crude shortages in some Northern Tier areas) must be replaced by additional shipments (inshipments) of refined products from other states. This constitutes a cost change, since inshipments will cost more than the products manufactured in Northern Tier refining centers.

(2) Canadian Crude Costs

Since less Canadian crude will be available under the curtailment plan, refiners in the Northern Tier will be buying smaller quantities of Canadian crude oil, and total costs in this category will decrease accordingly.

(3) Other Foreign Crude Costs

Canadian losses will be replaced, in part, by importation of other foreign crudes. Northern Tier refiners will be buying more crude from foreign sources other than Canada and, therefore, will experience increased costs in this category.

(4) Exchange Crude Costs

Some domestic-for-Canadian crude exchanges already have been negotiated for 1977. The cost of this crude will differ from Canadian imports, however, since oil is being exchanged for oil rather than dollars for oil. This study assumes a barrel-for-barrel exchange basis. Thus, for purposes of analysis, Northern Tier refiners who have such exchanges in effect will be paying controlled U.S. crude prices (plus transportation to Canadian refineries) for Canadian crude oil delivered to U.S. refineries.

(5) Entitlement Costs

Under the Entitlements Program designed to equalize raw materials costs to refiners across the U.S., refiners "earn" entitlements on the basis of the volume of crude oil processed. Therefore, since fewer barrels of crude are to be processed in the Northern Tier, refiners will be earning fewer entitlements--which will affect refining costs and, thus, product costs.

(6) Variable Refining Costs

Since fewer barrels of crude will be processed in the Northern Tier in 1977 as compared to the volume that would have been processed without the curtailment program, variable costs associated with product manufacture will be smaller. Costs for utilities, chemicals, and catalysts are examples of such variable costs that decrease with volume cutbacks. (Total crude costs also decrease as crude charge is reduced, of course, but for purposes of this analysis, crude costs are not considered as variable costs in this category.)

(7) Lost Profit

To the extent that more products must be brought into the Northern Tier as a result of reductions in Northern Tier refinery runs, refining profitability will be transferred to other parts of the U.S. This loss in profitability results from the inability of Northern Tier refiners to increase product prices under the current price control provisions. Normally, some of this loss in profit would not be incurred since product prices from curtailed Northern Tier refiners would be raised to the price levels of products procured through inshipments.

### 4.4.3 Quantification of Costs Effects

In order to measure the costs that scheduled 1977 Canadian crude curtailment will impose on products in the Northern Tier, two scenarios of crude/product supply were constructed. One of these, called the "1977 Curtailment Scenario", quantifies crude/product supply volumes from the most economical sources possible after crude curtailment at 1977 levels takes place. The other scenario, called "1977 Continued Canadian Supply Scenario," quantifies supply sources that would be used in 1977 if Canadian exports to the U.S. were continued at 1976 levels.

Once these scenarios were constructed and quantified in terms of volumes of products and raw materials supplied, cost effects from the two scenarios were derived and compared. The 1977 Continued Canadian Supply Scenario was used as a base from which the cost effects that would accompany a change to the supply pattern depicted in the 1977 Curtailment Scenario.

Development of supply scenarios first required the examination of 1977 product requirements in the Northern Tier in order to arrive at the apparent demand for products from Northern Tier refineries. This Refinery Demand figure, broken down by states and totaled, is shown in line 6 of Table 9. Other lines in this table illustrate the derivation of the 1977 Refinery Demand.

Line 1 presents the estimated consumption of refined products in the Northern Tier during 1977. These consumption figures were developed as a part of the long-range Northern Tier Study, Volumes I and II.

Line 2 presents the calendar-day crude charges to Northern Tier refineries during the first half of 1976.

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## TABLE 9

## DEVELOPMENT OF REFINERY DEMANDS FOR THE NORTHERN TIER STATES

(Thousands of Barrels Per Calendar Day)

| TABLE LINE NO. | PRODUCT REQUIREMENTS | MICH | MONT | WASH | WISC+ NDAK+ MINN | TOTAL |
|---|---|---|---|---|---|---|
| 1 | 1977 Product Consumption in Northern Tier | 556.0 | 79.0 | 235.0 | 591.0 | 1461.0 |
| 2 | 1976 Crude Runs in Northern Tier Refineries | 177.8 | 128.0 | 290.7 | 247.8 | 844.3 |
| 3 | 1976 Product Manufacture (.95 x 2) | 168.9 | 121.6 | 276.2 | 235.4 | 802.1 |
| 4 | 1976 Product Consumption | 541.0 | 79.0 | 230.0 | 577.0 | 1427.0 |
| 5 | Shipments of Products into Northern Tier States--1976 (4 - 3) | 372.1 | -42.6 | -46.2 | 341.6 | 624.9 |
| 6 | 1977 REFINERY Demand (1 - 5) | 183.9 | 121.6 | 281.2 | 249.4 | 836.1 |

NOTE: Figures in parentheses following line titles indicate computations for deriving the values shown in state and total columns. Circled numerals indicate line numbers.

Line 3 presents an estimate of product manufacturing volumes. This estimate is based on first-half, 1976, crude runs (as shown in line 2) and was calculated at 95 percent of total crude consumed. This, of course, assumes a 95 percent yield from crude processed, with the remaining 5 percent consumed as refinery fuel or lost in processing.

Line 4 displays estimated consumption of refined products for 1976, developed as a part of the aforementioned long-range Northern Tier study.

Line 5 shows shipments of products into the Northern Tier States during 1976. This figure was derived by subtracting product manufacture from product consumption (line 4 minus line 3), and represents the base level of net product shipments into the Northern Tier States. In construction of the 1977 Continued Canadian Supply Scenario, it was assumed that daily shipments of products into the Northern Tier in 1977 would be the same as in the first half of 1976.

The demand for product from Northern Tier refineries is shown in Line 6. This figure was derived by subtracting product shipments into the Northern Tier States from 1977 product consumption (line 1 minus line 5).

The two scenarios for crude and product supply are displayed in Table 10.

The first four lines under each scenario show the crude charged to refineries daily within the Northern Tier States from various sources.

Lines 1 and 8 are identical, showing that domestic crude charges are the same for both scenarios.

## TABLE 10

## 1977 SUPPLY SCENARIOS FOR THE NORTHERN TIER STATES

(Thousands of Barrels Daily)

| TABLE LINE NO. | SUPPLY SOURCES OF CRUDE PRODUCT | MICH | MONT | WASH | WISC+ NDAK+ MINN | TOTAL |
|---|---|---|---|---|---|---|
| | CURTAILED SUPPLY SCENARIO | | | | | |
| 1 | Domestic Crude (From Table 5) | 97.7 | 70.8 | 88.0 | 72.8 | 329.3 |
| 2 | Canadian Allocation (From Table 5) | 39.1 | 54.7 | 0.0 | 157.1 | 250.9 |
| 3 | Canadian Exchanges (From Table 5) | 0.0 | -3.0 | 15.0 | 3.1 | 15.1 |
| 4 | Other Foreign Crudes (From Table 5) | 29.8 | 0.0 | 182.0 | 0.0 | 211.8 |
| 5 | Total Crude Supply (1 + 2 + 3 + 4) | 166.5 | 122.5 | 285.0 | 233.0 | 807.1 |
| 6 | Product Manufacture (.95 x 5) | 158.3 | 116.4 | 270.8 | 221.4 | 766.9 |
| 7 | Product Inshipments (Table 9, line 6 - 6) | 25.6 | 5.2 | 10.4 | 28.0 | 69.2 |
| | CONTINUED CANADIAN SUPPLY SCENARIO | | | | | |
| 8 | Domestic Crude (Same as 1) | 97.7 | 70.8 | 88.0 | 72.8 | 329.3 |
| 9 | Canadian Allocation (Table 11, 13) | 75.7 | 57.2 | 56.7 | 189.8 | 379.4 |
| 10 | Canadian Exchanges | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 11 | Other Foreign Crudes (Table 11, 11) | 20.2 | 0.0 | 151.3 | 0.0 | 171.5 |
| 12 | Total Crude Supply (8 + 9 + 10 + 11) | 193.6 | 128.0 | 296.0 | 262.6 | 880.2 |
| 13 | Product Manufacture (.95 X 12) | 183.9 | 121.6 | 281.2 | 249.4 | 836.1 |
| 14 | Product Inshipments (Table 9, 6 - 13) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

NOTE: Figures in parentheses following line titles indicates computation to derive the values shown in state and total columns. Circled numerals indicate line numbers.

Lines 2 and 9 depict Canadian crude oil imported and distributed under the allocation program. Differences in Canadian allocation volumes reflect the effect of the curtailment program, with larger allocations in the Continued Canadian Supply Scenario.

Lines 3 and 10 show the effect of domestic-for-Canadian crude exchanges in each scenario. In the Curtailment Scenario, the volumes shown reflect exchanges already arranged for 1977. No exchanges are reflected in the Continued Supply Scenario since exchanges would be less if Canadian export supply to the U.S. were continued at 1976 levels and because only limited success has so far been achieved in such exchanges--even though curtailment is expected. It can be argued, of course, that exchanges would still be taking place under a continued supply arrangement with the Canadians since such exchanges are, indeed, taking place in 1976. It can also be shown, however, that assuming exchanges under Continued Canadian Supply conditions would have a relatively insignificant effect on product costs in the Northern Tier.

Lines 4 and 11 show the Northern Tier supply of foreign crudes other than Canadian for the two scenarios. Foreign crude supplies are, of course, much larger under the Curtailment Scenario since they will be used, where possible, to replace lost Canadian imports in 1977. The last two lines in each scenario reflect refined product supply sources.

Lines 6 and 13 depict products manufactured in Northern Tier refineries as used to satisfy Northern Tier Demand. The smaller volumes of product manufacture under the Curtailment Scenario are a direct reflection of the smaller crude supply available for refining.

Lines 7 and 14 show Product Inshipments under each scenario. Such additional shipments of products into the Northern Tier are not necessary under the Continued Canadian Supply Scenario. They are, however, very important factors in the Curtailment Scenario.

The construction of the Curtailment Scenario was a straightforward task. The crude charges for the refiners of each state (lines 1-4) are from Table 5 presented earlier in this report. Total crude supply (line 5) is a sum of the various supplies. Product manufacture from this crude supply (line 6) is derived by estimating a 95-percent yield. The inshipments--or additional products required for satisfying Northern Tier demands--is the difference between Northern Tier Refinery Demand (Table 9, line 6) and Product Manufacture (line 6).

The development of the Continued Canadian Supply Scenario was more complex. This scenario is intended to reflect crude/product supplies in 1977 if Canadian crude imports were continued at 1976 levels. As mentioned earlier, this is necessary in order to measure cost effects of the Canadian curtailment.

The Continued Supply Scenario was developed by taking crude supply patterns of the Curtailment Scenario and re-injecting Canadian supplies at 1976 import levels. Where this produces an oversupply situation, foreign crude was backed out to bring the supply situation back into balance. If one state was short of crude while another state had a surplus, it was assumed that Canadian crude would be shifted from the state with surplus supply to the state in short supply.

Thus, the Continued Supply Scenario simply represents a reasonable way to distribute the re-injected Canadian crude among the Northern Tier States. No attempt has been made to allocate this crude according to specific FEA rulings which could concievably be applied if 1977 Canadian crude availability does, indeed, match the levels of 1976.

The development of the Continued Supply Scenario is illustrated in Table 11.

Lines 1 and 2 represent current refinery plans for crude runs in 1977 and were taken from Table 5 presented earlier in this report. The Canadian crude exchange volumes, as mentioned earlier, were dropped in this scenario. The 1976 Canadian Allocation, shown in line 3, is the first-half, 1976, allocation rate taken from Table 5. The total available crude, shown as line 4, is the sum of the crudes shown in the first three lines. Line 5, showing required crude, is the estimated crude requirement to manufacture products in sufficient quantity to satisfy the 1977 demand for products from Northern Tier refineries (Table 9, line 6), assuming a 95-percent yield. Line 6 shows crude shortages which remain (or crude excesses which result) after re-injection of Canadian allocations into the crude availability picture. These shortages and excesses (indicated by negative quantities) result from subtracting required crude (line 5) from total available crude (line 4). Overall, approximately 40.3 MB/CD more crude is available under these Continued Canadian Supply assumptions than is required to meet the anticipated refinery demands. The states of Montana and Washington show crude surpluses, while the other states show shortages.

At this point in scenario development, a reasonable distribution of Canadian crude was made. This redistribution and its effects are shown in lines 7 through 12.

## TABLE 11

## DEVELOPMENT OF THE CONTINUED SUPPLY SCENARIO

(Thousands of Barrels Per Calendar Day)

| TABLE LINE NO. | DEVELOPMENT STEPS | MICH | MONT | WASH | WISC+ NDAK+ MINN | TOTAL |
|---|---|---|---|---|---|---|
| 1 | Planned Domestic Crude Runs (From | 97.7 | 70.8 | 88.0 | 72.8 | 329.3 |
| 2 | Planned Foreign Crude Runs Table 5) | 29.8 | 0.0 | 182.0 | 0.0 | 211.8 |
| 3 | 1976 Canadian Allocation | 58.7 | 58.7 | 91.7 | 170.3 | 379.4 |
| 4 | Total Available Crude ( 1 + 2 + 3 ) | 186.2 | 129.5 | 361.7 | 242.1 | 920.5 |
| 5 | Required Crude (Table 9, 6 ÷ .95) | 193.6 | 128.0 | 296.0 | 262.6 | 880.2 |
| 6 | Shortages ( 5 - 4 ) | 7.4 | -1.5 | -65.7 | 19.5 | -40.3 |
| 7 | Cover Shortages | -7.4 | 1.5 | 25.4 | -19.5 | 0.0 |
| 8 | Net Shortages or excesses | 0.0 | 0.0 | -40.3 | 0.0 | -40.3 |
| 9 | Net Canadian Crude 3 - 7 | 66.1 | 57.2 | 66.3 | 189.8 | 379.4 |
| 10 | Backed-Out Foreign Crude | -9.6 | 0.0 | -30.7 | 0.0 | -40.3 |
| 11 | Net Foreign Crude 2 - 10 | 20.2 | 0.0 | 151.3 | 0.0 | 171.5 |
| 12 | Shift Canadian | 9.6 | 0.0 | -9.6 | 0.0 | 0.0 |
| 13 | Final Canadian 9 - 12 | 75.7 | 57.2 | 56.7 | 189.8 | 379.4 |
| 14 | Total Crude 1 + 11 + 13 | 193.6 | 128.0 | 296.0 | 262.6 | 880.2 |

Note 1: Figures in parentheses following line titles indicate computations. Circled numerals indicate line numbers.

Note 2: Negative quantities in "shortage" lines indicate excess supply.

At line 7, to cover shortages, Canadian crude is backed out of Montana and Washington in order to eliminate shortages in other states. The excess crude in Montana is eliminated in this fashion, although Washington remains oversupplied, as reflected in line 8.

It was next deemed reasonable to redistribute the Canadian crude surplus in Washington to reduce foreign crude runs to the first-half, 1976, levels in other states and to use the remaining surplus to back foreign crudes out of Washington. The backed-out amounts are shown in line 10, and the net effects on foreign crude runs is presented in line 11. To complete the redistribution, 12 MB/CD of Canadian crude was shifted from Washington to Michigan, as shown in line 12, to yield the final Canadian crude distribution shown in line 13.

As can be seen in line 14, total crude supply has been made to match the required crude (line 5). Total crude supply is derived by summing domestic crude supply, foreign crude supply and Canadian allocations (lines 1, 11 and 13).

Finally, as shown in Table 12, the cost effects from 1977 Canadian crude curtailment in 1977 are isolated and assigned "added cost" values. This is accomplished by:

(1) Calculating the differences in volumes between the Curtailment Scenario and the Continued Supply Scenario, which was used as a base (lines 1 through 6).

(2) Identifying cost factors applicable to the calculated differences between scenarios (lines 8 through 14).

## TABLE 12

## COST EFFECT IDENTIFICATION AND ADDED COST DEVELOPMENT

| TABLE LINE NO. | | MICH | MONT | WASH | WISC+ NDAK+ MINN | TOTAL |
|---|---|---|---|---|---|---|
| | DIFFERENCES BETWEEN SCENARIOS (M BARRELS DAILY) | | | | | |
| 1 | Product Inshipments (Table 10, 7 - Table 10, 14) | 25.6 | 5.2 | 10.4 | 28.0 | 69.2 |
| 2 | Canadian Crude Supply (Table 10, 2 - Table 10, 9 ) | -36.6 | -2.5 | -56.7 | -32.7 | -128.5 |
| 3 | Other Foreign Crude Supply (Table 10, 4 - Table 10, 11 ) | 9.6 | 0.0 | 30.7 | 0.0 | 40.3 |
| 4 | Exchange Canadian (Table 10, 3 - Table 10, 10 ) | 0.0 | -3.0 | 15.0 | 3.1 | 15.1 |
| 5 | Entitlement BBLS ( 2 + 3 ) | -27.0 | -2.5 | -26.0 | -32.7 | -88.2 |
| 6 | Refinery Throughput (Table 10, 5 - Table 10, 12 ) | -27.0 | -5.5 | -11.0 | -29.6 | -73.1 |
| | COST FACTORS ($/BARREL) | | | | | |
| 7 | Product Inshipments | 13.82 | 13.90 | 14.37 | 13.85 | |
| 8 | Canadian Crude | 12.27 | 12.89 | 12.84 | 12.26 | |
| 9 | Other Foreign Crude | 13.59 | 0.00 | 13.44 | 0.00 | |
| 10 | Exchanged Crude | 0.00 | 9.06 | 9.06 | 9.06 | |
| 11 | Entitlement | -2.80 | -2.80 | -2.80 | -2.80 | |
| 12 | Ref. Variable Costs | 0.40 | 0.40 | 0.40 | 0.40 | |
| 13 | Base Fixed Costs | -1.58 | -1.58 | -1.58 | -1.58 | |
| | ADDED COST (M$ DAILY) | | | | | |
| 14 | Product Inshipments ( 1 x 8 ) | 353.8 | 72.3 | 149.4 | 387.8 | 963.3 |
| 15 | Canadian Crude ( 2 x 9 ) | -449.1 | -32.2 | -728.0 | -401.1 | -1610.4 |
| 16 | Other Foreign Crude ( 3 x 10 ) | 130.5 | 0.0 | 412.7 | 0.0 | 543.2 |
| 17 | Exchange Crude ( 4 x 11 ) | 0.0 | -27.1 | 135.9 | 28.1 | 136.8 |
| 18 | Entitlements ( 5 x 12 ) | 75.6 | 7.0 | 72.8 | 91.6 | 247.0 |
| 19 | Ref. Variable Costs ( 6 x 13 ) | -10.8 | -2.2 | -4.4 | -11.8 | -29.2 |
| 20 | Lost Profit ( 1 x 14 ) | -40.4 | -8.2 | -16.4 | -44.2 | -109.2 |
| 21 | Total Added Costs | 59.6 | 9.5 | 22.0 | 50.4 | 141.5 |
| 22 | Added Cents/Gallon ( 22 ÷ Table 9, 1) | 0.2 | 0.3 | 0.2 | 0.2 | 0.2 |

(3) Combined use of calculated differences and cost factors for computing "added cost" values in each of seven cost effect categories as shown in lines 15 through 21. (These are the cost effect categories identified and defined in subsection 4.4.2.)

(4) Summing all "added cost" values to arrive at total added costs and dividing this total by gallons of products projected to be consumed in 1977, (Table 9, line 1), to express these added costs in cents per gallon of product (lines 22 and 23).

The calculation of differences is explained by figures in the parentheses following the titles of lines 1 through 6. Application of cost factors is, likewise explained in parentheses after line titles in lines 15 through 21.

The following paragraphs are explanations of the cost factors used.

Line 8 shows costs factors applicable to inshipments of products required to meet Northern Tier demands in 1977. The costs used here are weighted averages (based on consumption) of the product prices in each state during the first-half of 1976. These values were taken from Volume II of this study.

Line 9 shows the cost factors applied to Canadian crude oil allocations. The cost factor here is the average price of Canadian crude imported into each state during the first half of 1976.

Line 10 shows the cost factors applied to foreign crude supplies other than Canadian. Two states are shown to be importers of such crude oil--Michigan and Washington.

The crudes chosen for import are those that most nearly replace the Canadian crude in quality and, thus, avoid refinery investment. These crudes were North African crude for import into Michigan and Indonesian crude for import into Washington. The laid-in cost of North African crude shipped by way of the Gulf Coast to Michigan and Indonesian crude laid into Washington were calculated based on 1976 prices and transportation tariffs.

Line 11 shows the cost factor or value of an entitlement to one barrel of domestic crude. This entitlement cost factor is shown as a negative, since receipt of an entitlement is a credit for the refiner--not a cost.

The Refinery Variable Costs were estimated as the variable costs associated with refining, excluding fuel. The fuel cost was excluded because the overall refinery yields used in this study, 95 percent, allow for the refinery fuel requirements to be supplied by refinery gas, coke, and liquid products.

The Base Fixed Costs, utilized in computation of lost profits due to transfer of refining profitability to other states, represent the estimated fixed cost and profit being recovered in the average barrel of product in the "refined products base period" for price control purposes. Assuming that price controls are still in effect in 1977, these costs cannot be recovered as refinery throughput in the Northern Tier declines.

Chairman HUMPHREY. The next witness is Mr. John P. Millhone, director of the Minnesota Energy Agency.

You have been with us before, Mr. Millhone, and I respectfully suggest that if you wish, you may paraphrase your statement and place it all in the record to conserve time, or you may read it in its entirety.

## STATEMENT OF JOHN P. MILLHONE, DIRECTOR, MINNESOTA ENERGY AGENCY, ST. PAUL, MINN.

Mr. MILLHONE. It is a pleasure for me to be here again. I would like to summarize my testimony. I would like to introduce Ron Visness, my assistant, who has worked on this particular problem to some extent.

The first point is that the petroleum problem is part of a matrix of problems that we face in Minnesota and all of my testimony will be primarily on it. There are natural gas problems, the use of coal, the use of alternative energy sources such as solar and other conservation measures. These are all part of the problem. However, petroleum has to be given the first priority in terms of our efforts to deal with the energy issues because it is most severe, most immediate, and the most devastating problem that we face in not only Minnesota but other Northern Tier States due to the rapid curtailment by Canada of its crude oil exports to the United States.

Petroleum is the largest source of energy used in Minnesota, providing an estimated 44 percent of the State's needs. Minnesota has no oil resources of its own. Petroleum enters the State primarily through crude oil and product pipelines, although small amounts enter by barge, railroad, lake tanker, and truck.

Canadian crude oil curtailments will have a heavy impact on the four Minnesota area refineries listed in chart 2 in my prepared statement as well as the other charts that will also graphically demonstrate my points perhaps better than I can with my words.

Chart 1 shows the petroleum supply coming into Minnesota and the products that leave Minnesota and go to other States.

At the lower righthand corner of chart 2 there are shown four refineries that are in or very close to Minnesota. They are the Koch, Ashland, Conoco, and Murphy refineries. The Murphy is right next door to Superior, Wis., and much of its product comes into Minnesota.

We have adjusted the data to show the percentage of Minnesota's refinery output that is used in Minnesota and the amount that goes to other States, so the bottom of chart 2, the pie chart, shows the amount of petroleum product that comes from these four refineries that are used in Minnesota, and the portion that goes to other States. So that the effect on Minnesota area refiners is not only on the State of Minnesota but on surrounding States as well, particularly Wisconsin, northern Michigan, the Dakotas, and Iowa.

The pie at the top of chart 2 shows how we get our premium products in Minnesota. It shows the percentage of petroleum products that comes from the Minnesota refineries and also shows the products that come into the State from refineries outside of Minnesota so, roughly, they are an even share. About half the product from our refineries goes out of the State and we get about half of our product from refineries outside of Minnesota.

Chart 3 is a projection of the demand for petroleum products in Minnesota. The bottom line is the Canadian crude and you can see there the sharp line. The next to the bottom line is the petroleum products that come into the State from refineries outside of the State and then the top line in the upper lefthand corner is the excess capacity that is fully using the pipeline providing product into State refineries where there would be that excess.

Chairman HUMPHREY. Up until what date?

Mr. MILLHONE. 1977. This is annual data, and although you may have a surplus annually because you have seasonal demands, it may be that you don't have the product there when you need it so you have to have some excess of capacity over demand in order to account for those seasonal variations.

We have historically in Minnesota been having an increase in petroleum products 3.3 percent. That is from 1965. Now, because of reduction in the demand that the energy agency foresees, largely as a result of increased efficiency of automobiles, that petroleum product demand is going to be, we predict, dampened down about one-third to 2.3 percent. This is based upon an econometric model, 35-sector input and output of Minnesota's analysis economy. However, in chart 3, we have a new factor and this is the substitution of petroleum product for natural gas and the portion of the trend line that extends above that line without substitution accounts for the substitution of petroleum products for natural gas. So our demand in the future, because of that offsetting, is going to be fairly close to what it has been in the past. Here you can see that a continuing demand and a gaping shortfall goes really to monstrous proportions early in the 1980's and long before that it becomes a very serious problem.

If we were using our model again, the year 1980, if we do not have an answer by alternative pipelines by that time, we anticipate that there will be a loss of 48,000 jobs in Minnesota and that's such a devastating impact that it is something we simply can't allow to happen.

Chairman HUMPHREY. As that excess capacity line diminishes, you run the danger of wintertime shortages—spot shortages?

Mr. MILLHONE. That's right. I wouldn't be quite as optimistic as Mr. Zarb that we would not be having any problems this winter. The kinds of problems I would think might very well occur with average temperature would not be long term, and they would not be statewide, but there would be certain local short-term problems that would become much more widespread and intense if we had a severe winter.

Chairman HUMPHREY. You are speaking now of the coming winter?

Mr. MILLHONE. I'm talking now of the coming winter.

Now, chart 4 shows the effect of the Williams Bros. pipeline proposal that was mentioned earlier.

There we have taken the capacity of that pipeline and divided it in half because, as we saw in the earlier part, half of the product produced in Minnesota goes to other States. We are looking here just at the effect on Minnesota's supply position.

The effect of it is for 1- or 2-year periods to make a significant, meaningful, short-term increase in what would otherwise be available here. So in terms of 1976 and 1977, it is extremely important that we do what we can to help that project get completed.

Chairman HUMPHREY. Is it your judgment that this project can be completed on schedule?

Mr. MILLHONE. It is my judgment that it can be if the private and public sector worked diligently together. I've talked with Mr. Vernon Jones. They are permitting procedures that were concerned about processing as rapidly as possible with a target date of completing the permitting requirements, assuming that the data justifies the permits being issued by the start of the construction season next year and, if that occurs, then, testimony from Williams Bros. is that they think they can complete it in one construction season, so anyone who is going to gamble on the completion of a pipeline project on time would probably be seen as an optimist but we are doing everything that we can to move this project along as far as possible.

Chart 5 brings in the effect of the Kitimat pipeline. Here, again, you can see that the effect of that is in 1979 to provide a capacity of service in this area that is above what our projects' demand is and would provide a comfortable level of petroleum product for the Minnesota area. There is in 1978–79 a shortfall that could be quite acute, could be, and there, I think, the swaps come in, kind of easing of the supply problem.

Chairman HUMPHREY. I have been concerned about that transition area.

Mr. MILLHONE. That's correct. That's going to eliminate that red mark, I would hope in the 1978–79 period.

Chairman HUMPHREY. Are you projecting that the Kitimat pipeline into Edmonton can be completed by 1979?

Mr. MILLHONE. By 1979, yes. I might get into that a little bit.

Chairman HUMPHREY. I just looked at you because I thought I was the all-time optimist.

Mr. MILLHONE. I have hedged my judgment somewhat.

Chart 6 shows the effects of delays. We are looking at what would happen if we get two delays, a 1-year delay in the Williams Bros. pipeline and 2-year delay in the Kitimat pipeline. You can see that it will be well below the anticipated demand. We would have some severe supply problems, both in 1977 and 1978, in fact to the early 1980's, at least to 1981, if these projects are not completed in a timely manner. So I think this is certainly a danger and this is an effort to dramatize just how important it is that we move ahead on these projects rapidly.

Chairman HUMPHREY. This, again, places an ever-increasing emphasis on offshore oil swaps to alleviate the imminent energy shortages in case of delays in completing the pipelines?

Mr. MILLHONE. That's correct.

Chairman HUMPHREY. You have the fuel industry considering the Kitimat line. They are also covering the northern tier line. Would this extra commitment slow down the possibility of any one line being completed on time?

Mr. MILLHONE. In the latter portion of my testimony I comment some on the Bonner and Moore study. I think we can go to that.

The Bonner and Moore study has some good data in it and some interesting scenarios. However, it also in our view has some inaccurate information and some that is not fully explained. So I don't feel it is a good vehicle on which to make policy decisions. In my view, the report provides too favorable a description of the proposed northern tier pipeline from Puget Sound and not as favorable a description as should be given of the Kitimat proposal.

The northern tier proposal in the Bonner and Moore study depends upon its final feasibility for the ability to sell products of the Twin Cities area and, when you move into that market, you are in an area that is supplied by refineries that have lower cost sources of crude oil and that's a very soft expectation.

In addition, there are some cost comparisons of the Kitimat pipeline and a similar size pipeline to the Twin Cities area and the northern tier pipelines given as just 60 percent of the cost-per-mile of the northern, of the Kitimat line. There's no explanation for that cost difference.

The Energy Agency supports the Kitimat pipeline. It would minimize environmental impacts by the maximum use of existing pipeline segments and by providing an alternative to the increased tanker shipment in the Puget Sound area which is of interest to both the United States and Canada. The use of the Canadian route would preserve the future flexibility regarding Canadian-American exchanges and, while we wanted to be as independent as possible, we also want to keep that flexible interchange available. The northern tier pipeline in its relation to national security is not an issue in Minnesota and I do not think it should be a national issue. The Canadian curtailment of crude is not a hostile act but is simply a Canadian response to a projected supply deficit. It has nothing to do with American oil being shipped through Canada. That is, the security problem has nothing to do with the shipment of American oil through Canada. Any attempt to create such a national security issue obscures the vital interdependencies which exists with our Government and the Canadian Government.

Perhaps more importantly, and here we are getting into the time, it is the only pipeline that can be financed, granted permits, and operated economically without involving the Washington State refineries. This is important at present because the Washington refineries are involved in litigation and it looks like it will be extremely lengthy, on their right to use Puget Sound. So, although we take exception to some of these provisions in the Bonner and Moore study, we concur with its conclusion and the conclusion expressed today by Mr. Zarb, that industry should be free to solve the problem and Government should remain at the sideline at this time as long as it appears that the refiners involved and the pipelines are moving ahead fairly rapidly to come to agreement on the construction of the Kitimat pipeline. We also agree that the Federal Government and the affected States should closely monitor private efforts to reach an agreement to build the Kitimat pipeline and should be prepared to act as necessary in order to move this project along.

This is an area where the States and the Federal Government have to work together. The Government and the private sector have to work together and it looks now as if that agreement is working well. But in this area the proof of the pudding is in the eating and we don't have a pipeline yet and we need to be certain that there aren't any catches because the impacts in Minnesota and other northern States would be quite tremendous.

Chairman HUMPHREY. What is the progress thus far on the Kitimat Pipeline proposal?

Mr. MILLHONE. At the present time the refiners and the pipeline company that would be involved are trying to put together the terms of the agreement on the financing and the size. It is my understanding that there will be a permanent request to the Canadian Government in the fourth quarter of this year.

Now, the initial timetable for this project was an attempt to get all of the permitting completed by the end of this next year so they could get into the construction and have a complete date in the fall of 1978. I think that's been moved back 1 year to 1979.

Chairman HUMPHREY. Yes.

Mr. MILLHONE. I think it may be there are other witnesses available, either to present oral or written testimony later, that could provide a more detailed description of the status of that project.

Chairman HUMPHREY. It is my understanding that the Canadian officials at the Federal level are being very cooperative in negotiating with these companies and our Government. I also understand you have provincial laws that affect these negotiations.

Mr. MILLHONE. It was my understanding that the National Energy Board, once it makes its decision, can pretty much override the Provincial government.

Chairman HUMPHREY. That's true, but there is also a certain amount of political warfare. I want to point out that we have met with the Canadian officials and they seemed most helpful and most cooperative.

Mr. MILLHONE. We're certainly interested in working with you, Senator, and your committee, with the Federal Administrative Office, and with everyone we can.

Chairman HUMPHREY. We have been meeting with the Canadian parliamentarians as well—parliamentarians from the western Provinces of Canada and the Provincial Governors. We've had these informal types of contact going on and not long ago we had the Governor of the Province of Alberta with us in Washington for meetings. We have also met with the parliamentarians from British Columbia as far as Manitoba.

I serve on the committee of the Congress that meets with the Canadian parliamentarians and we feel that it is important to work with them as well as with the executive officers because, as you know, even in our own country, members of the legislative body do have a way of getting involved.

All right. Was there anything further?

Mr. MILLHONE. Nothing further. Thank you.

Chairman HUMPHREY. First, I want to commend you on an excellent statement. We were privileged to have your statement in advance. It is well documented and I hope that it will be studied most carefully by those who are interested in the problems that we are addressing here today.

I have talked to you about these offshore oil swaps and I worry about those gap periods and see the only possible way of meeting those periods of curtailed Canadian oil, to be through offshore oil exchanges. We will have our State Department witness talk with us about that. There is, as I indicated before, only a limited capacity to swap U.S. domestic oil for Canadian oil. Perhaps only 20 percent of Minnesota's requirement in 1978–79 can be supplied that way. Would you agree with that?

Mr. MILLHONE. Yes, I would agree with that.

Chairman HUMPHREY. Since we have proceeded with this official sense of urgency on these negotiations for offshore oil exchanges, do you feel they are being well managed?

Mr. MILLHONE. Senator, I don't feel I am in a position to answer that question. It has occurred between the affected companies and the FEA and Commerce and I haven't been monitoring what's happened there closely enough to know whether it has been managed diligently. I certainly hope that it has.

Chairman HUMPHREY. That's a prudent position, I would say. You have been taking some action here in Minnesota because of legislation and recommendations by your agency to conserve on fuel. The State mandated a prohibition of decorative gas fixtures, for example, and now the FEA Extension Act, as you know, allows the FEA Administrator to make grants to States in order to assist low-income families in insulating their homes.

Will your agency be ready with a program to move these funds out quickly?

Mr. MILLHONE. Senator, we will be; in fact, Minnesota has some State legislative funds to accomplish this same purpose.

Chairman HUMPHREY. Do you have a tax credit program here?

Mr. MILLHONE. We have a grant program, loans and grants for low-income people to winterize their homes. The first loan went through just the last couple of weeks for a woman in Duluth and that program is currently in phase and we will be happy to have the additional Federal money when it is appropriated.

Chairman HUMPHREY. Are you the first in the Nation to do this?

Mr. MILLHONE. I believe so.

Chairman HUMPHREY. We get a lot of mail on this, I might add, and the Federal activity in this area has, regretably, been long overdue. I want to complement you on your initiative. Could you give us an assessment of the impact that tax credits, grants or loans would have on home insulation here in Minnesota?

Mr. MILLHONE. Probably the largest problem currently for really effective conservation in Minnesota in the building area is the shortage of capital. Although you can spell out that, if you insulate your home, you will recover your investment within a certain period of time, and you could do this for company commercial establishments as well, oftentimes immediate capital that is required for that simply has other priority demands, so the use of loans and grants and loan guarantees and tax credits are all devices which I see as very desirable because they shift priorities and they shift capital into these kinds of building programs.

Chairman HUMPHREY. We have the manpower and the insulation product in adequate supply, do we not?

Mr. MILLHONE. We haven't experienced any shortages there at this time. There are some reliability problems of certain costs of insulation, so you have to have some kind of standards, a program that is done with the insulation program to make sure you get your money's worth, but that's more a matter of the kinds of problems that occur

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any time you rapidly expand the activity of a certain segment and it is certainly nothing that can't be dealt with with proper guidelines and constraints.

Chairman HUMPHREY. Are the people in Minnesota aware of the assistance that is available under State and Federal laws?

Mr. MILLHONE. We are trying, Senator, to get this information out to Minnesotians and this is an area that we need to do further work in. The Minnesota government does have an energy conservation information center, so we have a toll-free number where people can call and reinsulation guidelines so that people can take their home and put in the type of construction, the size, what fuel they are using, whether they have any insulation now, and can determine from a fairly simple computer program what this optimum new insulation would be and when it would be paid off. So we are trying to provide the information people need in order to make these kinds of decisions.

At the same time, I feel as if we have a further road to go to get this information broadcast like it should be.

Chairman HUMPHREY. That's very fine and we are very pleased that you have taken the position you have. I want to commend you.

By the way, I want to extend thanks to you and your agency for the splendid cooperation and effort in the Solar Energy Research Institute project. We are still hopeful that we may see that blossom here in Minnesota.

Mr. MILLHONE. We are very excited about the prospect, primarily because we think an excellent job would be done by having the institute located here.

Chairman HUMPHREY. I agree wholeheartedly.

Thank you very much, Mr. Millhone, your prepared statement will be printed in the hearing record.

[The prepared statement of Mr. Millhone follows:]

PREPARED STATEMENT OF JOHN P. MILLHONE

Good morning, Mr. Chairman.

My name is John P. Millhone and I am the director of the Minnesota Energy Agency. I welcome the opportunity to participate in this hearing. The scheduling of this meeting shows your concern for public understanding of complex economic issues and your recognition of the crucial role of the States in the energy field.

The most immediate and potentially devastating energy problem facing Minnesota and several of its neighboring States is due to the rapid curtailment by Canada of its crude oil exports to the United States. Fortunately there are some supply alternatives. The main thrust of my testimony will examine this curtailment problem and these supply alternatives.

These issues can best be understood after a brief description of Minnesota's energy position. Minnesota last year obtained 44 percent of its energy from petroleum, 29 percent from natural gas, 17 percent from coal and the remaining 10 percent from nuclear and hydropower. This closely reflects the national pattern.

The State last year used 30 percent of its energy for residential and commercial purposes, 32 percent for transportation, and 29 percent for industrial purposes. This is a little higher than the national figures for residential and commercial and transportation purposes and lower for industrial uses.

Each State's matrix of energy supplies and uses is unique. The Minnesota picture, however, is similar to other Midwestern States. A State's energy policies grow from its unique supply-demand equation.

In Minnesota, we have a six-point energy plan. Stated simply, it is:

First, to maximize the availability of petroleum products.

Second, to obtain our equitable share of natural gas and use it for the highest priority purposes.

Third, to develop and implement a coal use plan.

Fourth, to encourage the maximal development of alternative energy resources.

Fifth, to achieve the greatest possible efficiency in the generation, distribution and use of electricity.

And sixth, and most important, to conserve energy in every reasonable manner possible.

These goals interlock and reinforce each other.

The remainder of my testimony will concentrate on efforts to obtain reliable petroleum supplies. This important objective is part of a comprehensive State energy plan.

Petroleum is the largest source of energy used in Minnesota providing an estimated 44 percent of the State's energy needs in 1974. Minnesota has no oil resources of its own. Petroleum enters the State primarily through crude oil and product pipelines, although small amounts enter by barge, railroad, lake tanker, and truck.

Canadian crude oil curtailments will have a heavy impact on the four Minnesota area refineries listed in the table at the bottom. Historically, these refineries have received the majority of their crude oil from Canada. In 1974, some 165,000 barrels a day or 88 percent of their crude oil supplies were Canadian. Conoco, near Duluth, Minnesota, and Murphy in Superior, Wisconsin are completely dependent upon Canadian crude.

The data presented in the pie charts and the following graphs relate to Minnesota only. Since the refineries located in the Minnesota-Wisconsin region also serve parts of Wisconsin, Iowa, Michigan, and the Dakotas, we have adjusted the data to arrive at the share of the refinery production sold in Minnesota. This allocation is very difficult to compute with a high degree of accuracy since actual market shares shift with competitive forces. This is our best guess at the volume of product supplied to Minnesota by each of the supply sources. The total volume supplied from all sources has been checked against Bureau of Mines figures, FEA data, and data received from Minnesota's petroleum tax division.

The four refineries (Koch, Ashland, Murphy, Conoco) sold about 70 percent of their output in Minnesota during the high production years of 1972 and 1973. The other 30 percent was delivered to neighboring states. However, recent data indicates that only 55 to 60 percent of refinery output was sold in Minnesota in 1974. Nearly 90 percent of the production went to gasoline, distillate, and residual fuel oil. The remaining 10 percent includes other products such as asphalt, road oil, coke and LPG (propane).

The top pie chart is the starting point for the four petroleum supply/demand scenarios which follow. The chart shows the source of the gasoline, distillate and residual fuel oils used in Minnesota in 1974.

The flow of these petroleum products into the State varies with the season. Gasoline deliveries increase during the summer months, primarily due to recreational travel demand, and the demand for fuel oil is greatest during the winter months for space heating purposes. Also, the shipment of product by lake tanker and barge is not possible during the winter months, so both refineries and product pipeline must increase their throughput.

The first graph is a projection of the demand for gasoline, distillate and residual fuel oils in Minnesota through the year 1985. The units are in thousand barrels per day. Since 1965, the Minnesota demand for these products has increased at a rate of 3.3 percent per year. Over the next 10 years it is projected that under normal circumstances the consumption of these products will increase at a rate of 2.3 percent per year. However, for the first time, Minnesota is faced with a declining supply of natural gas. This will substantially increase the need for fuel oils, especially the heavier residual fuel oils. By 1981 the demand for residual fuel oils will more than double because of the natural gas curtailment. The demand for distillate is expected to increase only 5 percent because of natural gas curtailments. Because of the substitution of fuel oils for curtailed natural gas total petroleum demand is expected to increase by 3.5 percent per year as indicated by the line at the top of the graph.

The brown portion at the bottom of the chart represents the output Minnesota is expected to receive from the four area refineries. After 1977 refinery output will decline sharply, because of Canadian crude oil curtailments. The blue portion of the chart represents petroleum product inshipments. The bulk of these products enter the state through the Williams Brothers or Amoco pipelines. A smaller share enters the State by other modes of transport—barge, rail, lake tanker, truck. The yellow portion of the chart represents the excess capacity of the product pipelines on an annual basis.

As the excess supply capacity approaches zero, the supply/distribution problem will become more difficult to manage, and wintertime spot shortages can be expected to occur. These shortages will begin in the rural areas, and as the supply situation becomes tighter they will cover larger areas and become more frequent. Under the current FEA priority allocation rules and without any of the new proposed pipelines, the 1980 refinery runs could be reduced to 20 percent of the 1974 level. This would impose a heavy strain on the storage/distribution system for petroleum products. Not all of the projected shortfall could be made up by expanding existing transportation modes. If industry were forced to curtail because it could not obtain the needed fuels, the State could experience a loss of 48,000 jobs.

It becomes obvious from this chart that the four Minnesota area refineries will have to tap alternate sources of crude oil or Minnesota and the surrounding market area will begin to experience severe shortages of petroleum supplies.

Vernon Jones, president of Williams Pipeline Co., recently announced that a new 123 mile, 18 inch pipeline would be installed from Mason City, Iowa, to the Twin Cities. The new facilities would be in operation by October 1, 1977, with a capacity of 80,000 BPD. Once the line is in place the company could expand its oil deliveries to "Northern Tier" States from 80,000 to 130,000 barrels a day by installing additional horsepower on the system.

The second chart indicates how the additional throughput capability of the Williams Pipeline Co.'s proposal would affect Minnesota's supply situation. If this project is completed on time, it would hold back petroleum shortages one or possibly two years. This would provide the refiners with the urgently needed time to install a new crude oil pipeline as a larger term solution.

The long term solution to the Canadian crude oil curtailment, supported by the State of Minnesota, is a proposed trans-provincial pipeline, that would stretch from Kitimat, British Columbia, to Edmonton, Alberta, Canada. This trans-provincial proposal has the strong support of refiners in Montana, North Dakota, Minnesota, Wisconsin and Michigan. Only the Washington State refiners are not involved, possibly because of their attempt to supply that state through tanker shipments rather than any sort of pipeline.

The third graph illustrates the projected supply/demand situation for Minnesota with both the proposed Williams and the proposed Trans-provincial line installed. We believe this is the best solution for all of the Northern Tier States. If these two projects are completed on time, there would be only a minor shortfall in petroleum products in 1979. This small shortfall could be made up by doubling the present level of shipments by the other transport modes such as barge, lake tanker, railroad, and truck, or by swaps with the Canadians.

Product pipelines and crude oil pipelines are competitors for the end-use market. Graph three shows product pipeline shipments increasing to the capacity of the lines. The reason for this is the tight supply of crude oil during the next few years. For example, the Williams expansion will only allow crude oil supplies in 1978 to be about the same as the 1976 level. This would mean an increasing market share for the product pipeline users. There seems to be a strong incentive for the refiners to develop swaps of U.S. oil for Canadian oil in order to protect their market shares. Swaps would tend to reduce product pipeline throughput, and ease the capacity constraint.

Also, the Williams Brothers line would have the flexibility to ship both crude and petroleum products. It is reasonable to predict that as demand increases, the trans-provincial line would provide the bulk of the crude oil and the Williams line would shift back to petroleum products.

I also would like to make a few comments on the study by Bonner and Moore, Inc., a consulting firm hired by the Federal Energy Agency to study the economic, legal, environmental and socioeconomic impacts of ways of supply oil to the Northern Tier States.

The Bonner and Moore report, while containing some accurate data and interesting hypotheses, also contains much unsubst‐ntiated and apparently inaccurate data. For this reason, it should not be used as a basis for policy decisions.

The report provides a too favorable description of the proposed Northern Tier pipeline from Puget Sound across the northern United States to Clearbrook, Minnesota. It fails to recognize many of the advantages of the proposed Trans-provincial pipeline from Kitimat, B.C., to Edmonton, Alberta.

The Northern Tier pipeline depends on demands east of Minneapolis to keep its tariff low, yet this demand would be soft because of competition from refineries supplied with cheaper sources of crude oil. The study prices a Northern Tier pipeline at only 60 percent of the trans-provincial pipeline, with no explanation of this significant cost difference.

The trans-provincial route would minimize environmental impacts by the maximum use of existing pipeline segments and by providing an alternative to increased tanker shipments in the Puget Sound area.

The use of the Canadian route would preserve the future flexibility regarding Canadian-American exchanges. While our goal is to be independent of Canadian crude, we should not reject the possibility of working together.

The Northern Tier pipeline and its relationship to national security is not an issue in Minnesota and it should not be a national issue. The Canadian curtailment of crude is not a hostile act, but is simply the Canadian response to a projected supply deficit. It has nothing to do with American owned oil being shipped through Canada. Any attempt to create such a national security issue obscures the vital inter-dependencies which already exist with our continent-sharing neighbors.

The trans-provincial pipeline is the only pipeline that can be financed, granted permits, and operated economically without involving the Washington State refineries. This is important because, at persent, the Washington refiners are involved in lengthy litigation over their right to use large crude oil tankers in Puget Sound.

Although we take exception to some portions of the Bonner and Moore report, we concur with its conclusions that industry should be free to solve the problem and Government should remain on the sideline at this time. However, we also believe the Federal Government and affected States should closely monitor private efforts to reach an agreement to build the trans-provincial pipeline and should be prepared to act as needed to support these efforts.

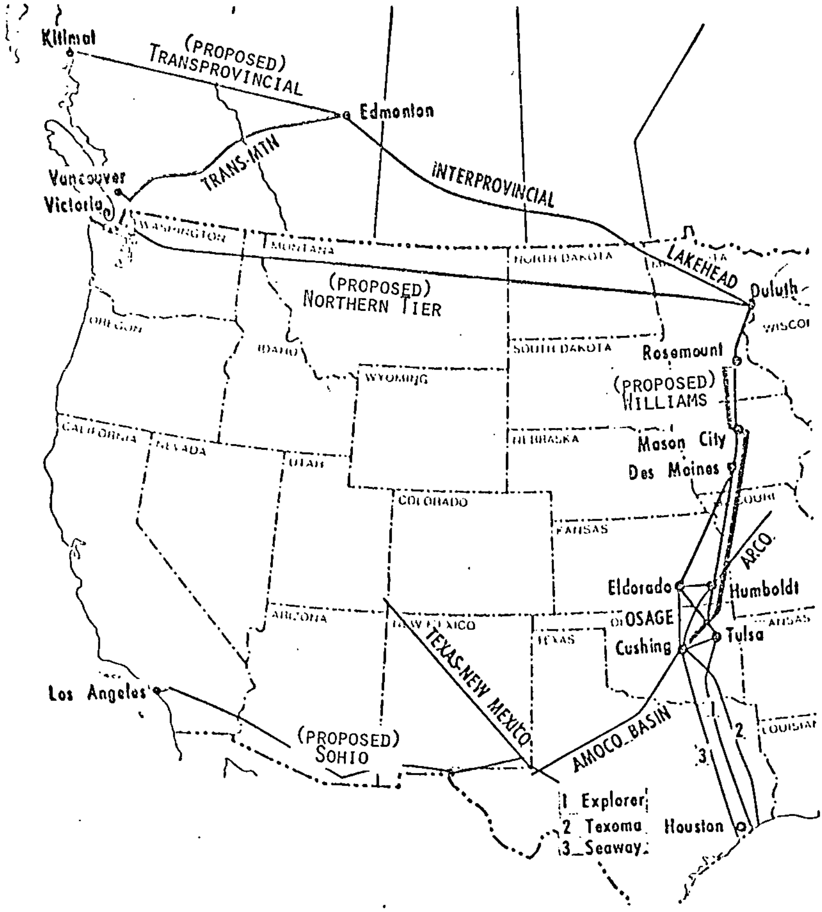
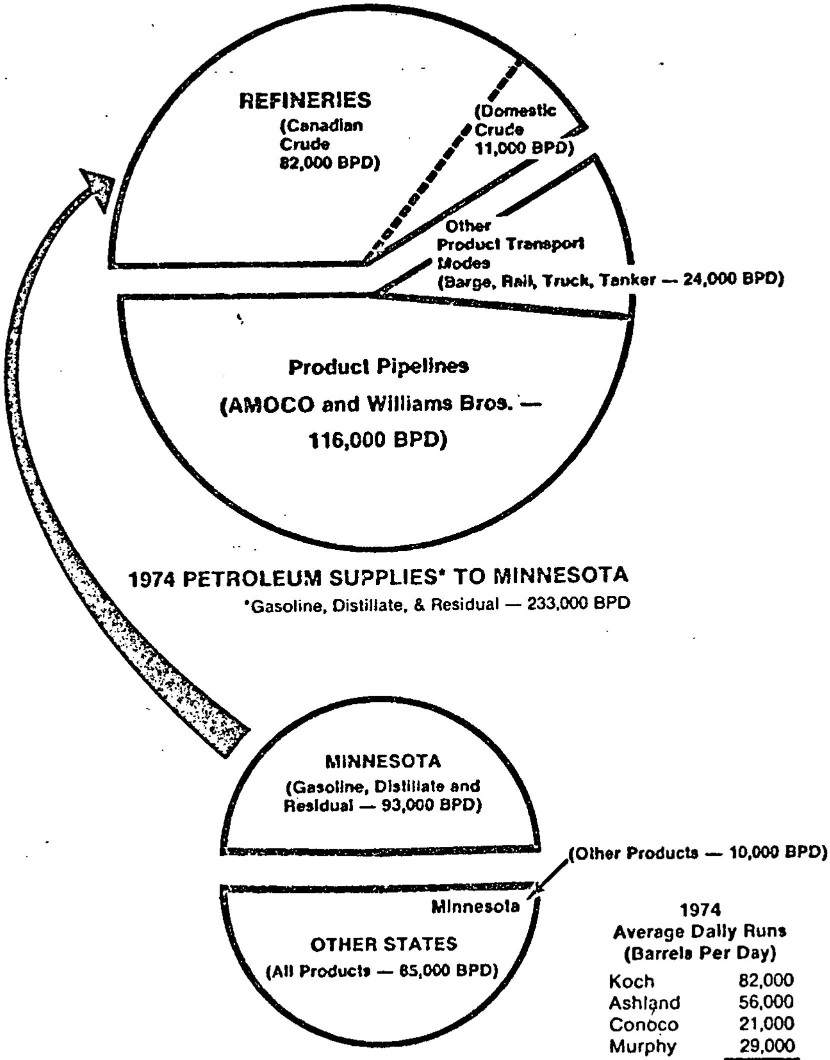

Kitimat
(PROPOSED)
TRANSPROVINCIAL
Edmonton
TRANS-MTN
INTERPROVINCIAL
Vancouver
Victoria
WASHINGTON
MONTANA
NORTH DAKOTA
LAKEHEAD
Duluth
(PROPOSED)
NORTHERN TIER
OREGON
IDAHO
SOUTH DAKOTA
Rosemount
WYOMING
(PROPOSED)
WILLIAMS
CALIFORNIA
NEVADA
NEBRASKA
Mason City
UTAH
Des Moines
COLORADO
KANSAS
APCO
Eldorado
Humboldt
ARIZONA
NEW MEXICO
OSAGE
TEXAS
Cushing
Tulsa
TEXAS-NEW MEXICO
Los Angeles
AMOCO BASIN
(PROPOSED)
SOHIO
1 Explorer
2 Texoma
3 Seaway
Houston

**CHART 1**



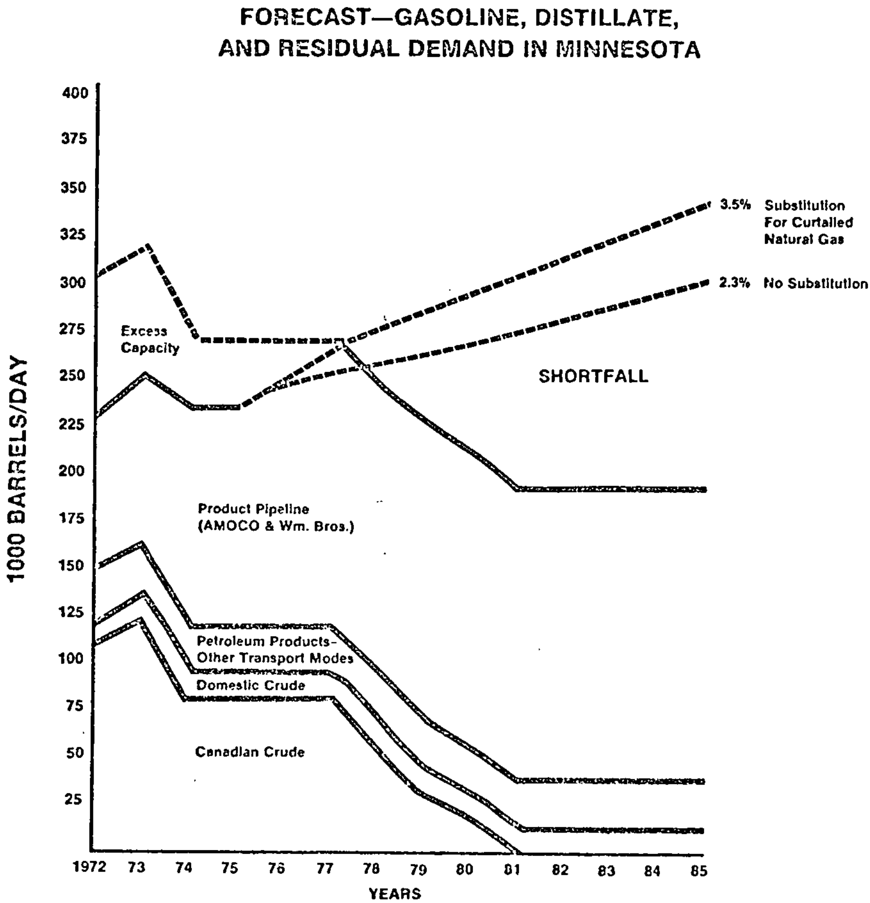

1974 PETROLEUM SUPPLIES* TO MINNESOTA

*Gasoline, Distillate, & Residual — 233,000 BPD

1974 REFINERY MARKET SHARE

| 1974 Average Daily Runs (Barrels Per Day) | |
|---|---|
| Koch | 82,000 |
| Ashland | 56,000 |
| Conoco | 21,000 |
| Murphy | 29,000 |
| Total | 188,000 |

CHART 2


FORECAST—GASOLINE, DISTILLATE, AND RESIDUAL DEMAND IN MINNESOTA
1000 BARRELS/DAY
400
375
350
325
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275
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200
175
150
125
100
75
50
25
1972
73
74
75
76
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78
79
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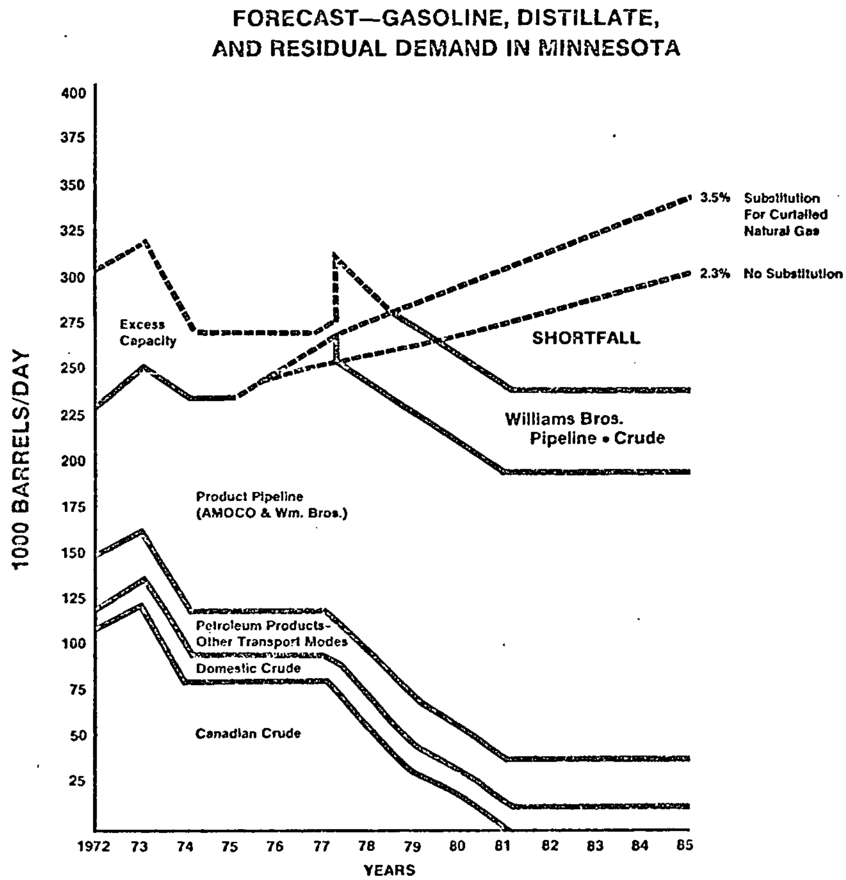
81
82
83
84
85
YEARS
3.5% Substitution For Curtailed Natural Gas
2.3% No Substitution
Excess Capacity
SHORTFALL
Product Pipeline (AMOCO & Wm. Bros.)
Petroleum Products-Other Transport Modes
Domestic Crude
Canadian Crude

CHART 3


FORECAST—GASOLINE, DISTILLATE, AND RESIDUAL DEMAND IN MINNESOTA
1000 BARRELS/DAY
400
375
350
325
300
275
250
225
200
175
150
125
100
75
50
25
3.5% Substitution For Curtailed Natural Gas
2.3% No Substitution
Excess Capacity
SHORTFALL
Williams Bros. Pipeline • Crude
Product Pipeline (AMOCO & Wm. Bros.)
Petroleum Products-Other Transport Modes
Domestic Crude
Canadian Crude
1972
73
74
75
76
77
78
79
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81
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83
84
85
YEARS

CHART 4

## FORECAST—GASOLINE, DISTILLATE, AND RESIDUAL DEMAND IN MINNESOTA

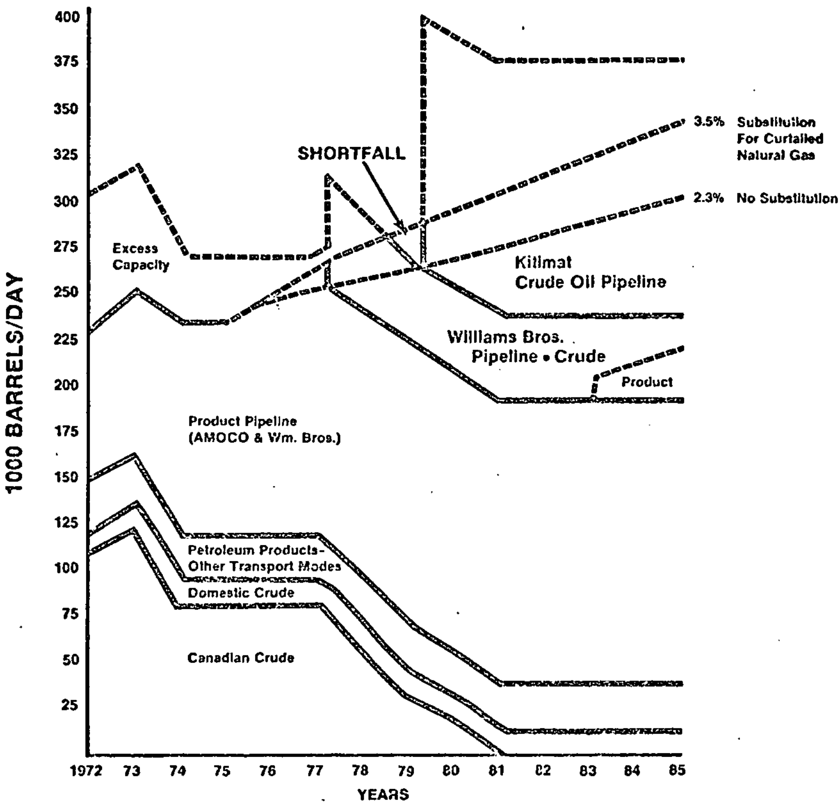



CHART 5

FORECAST—GASOLINE, DISTILLATE, AND RESIDUAL DEMAND IN MINNESOTA

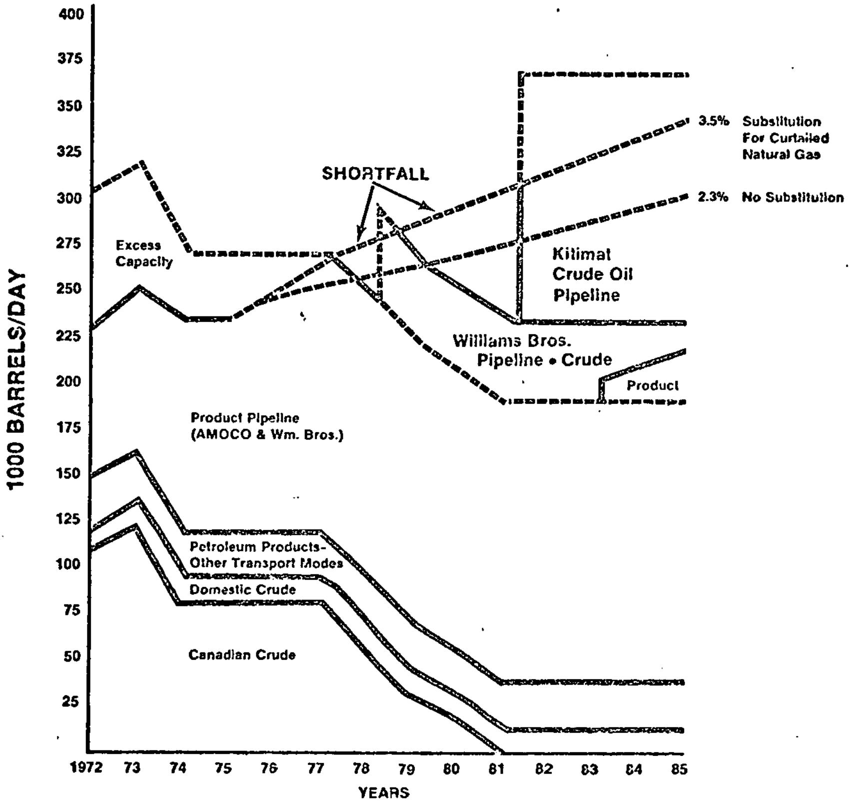



CHART 6

Chairman HUMPHREY. Our next witness is Mr. Lawrence Raicht from the State Department.

Mr. Raicht, you have prepared testimony, I believe?

Mr. RAICHT. Yes; I do. In order, again, to save time of this committee and yourself, I suggest that we can simply enter my prepared statement in the record.

Chairman HUMPHREY. That will be fine and you may summarize it if you wish. I would like you to inform us with regard to the necessity of offshore oil swaps and give us some indication of what is underway in terms of negotiations with Canada.

I might add that I hope after the morning's discussion you will convey the sense of urgency back to my good friend, the Secretary of State. Once he gets through with Africa, he should settle down and get some extra things going with Canada.

## STATEMENT OF HON. LAWRENCE R. RAICHT, DIRECTOR, OFFICE OF FUELS AND ENERGY, DEPARTMENT OF STATE

Mr. RAICHT. I share in many respects the judgments of Mr. Zarb concerning the energy supply prospects for the Northern Tier, particularly in Minnesota, over the next several years. We, too, view the number of different long-term supply alternatives such as the Kitimat TransProvincial Line and some of the others which have been proposed as important for the long term beyond 1980. But there is a gap. There is a gap which will begin to assume larger proportions after 1977 as Canadian oil exports are phased out. It is unclear, as yet, exactly what the Canadian export level will be in January of 1977. We do have the schedule based upon the NEB's most recent report which was issued earlier this year, but the NEB has scheduled hearings on oil supply and demand in Canada and exports which will begin in October, next month, on the basis of which there may very well be an adjustment in the export schedule, either up or down.

As a matter of fact, I think we also have benefited in some measure from the failure on the part, if I can characterize it as such, on the part of Canadian industry to move as rapidly as was originally expected with regard to the construction of the Sarnia-Montreal line. The delay in getting that pipeline completed and operational has probably resulted in a delay in the phasedown of exports from Canada. Originally it was scheduled to go to 380,000 barrels a day in July of this year. In fact, it looks like it will not phase down to that level until October. I don't think we will know precisely what the level will be in 1977 until the NEB has completed its own analysis, but there is a gap, that's fairly clear. We have long been concerned about it and I think John Hill from the FEA at the hearings you had last year provided you with a copy of the report which was prepared by the joint United States-Canadian working group on swaps, which we initiated last year, in March of 1975. We recognized that swaps could play a role.

The original working group report was very carefully worded. It specifically did not exclude offshore swaps. As a matter of fact, it pointed out, I think, a fairly substantial investment savings to refineries in the Montreal area who were the natural recipients of such exchanges, for participating in these exchanges, investment savings, particularly.

You asked that I focus also on what that status of negotiation is on such proposals. We have recognized that we need to move to offshore swaps as quickly as possible. We recognize a constraint that exists in the United States. You have both the swappers in the United States and the "Priority 2" refiners who are not getting Canadian oil, who are competing for a limited pipeline capacity, so we have logistical constraints upon that pipeline capacity limiting how much oil can be moved north from the Gulf of Mexico, whether it is domestic oil or imported oil, any oil for those refineries that have become dependent upon Canadian crude over the past 20 years has to move up that same pipeline to connect to any pipeline carrying oil into Canada.

Our own judgment is that we are already, with the limited number of swaps that FEA has already approved, reaching the limits of the capacity of that pipeline and that we have to expand the parameters for such swaps. We do think that we want to go and talk to the Canadians about it. We have scheduled a meeting with the Canadians in October, at which we intend to raise this issue.

We hope shortly to put a proposal forward to them that would lay the basis for a more in-depth and knowledgeable discussion of such swaps. The question really is how will Canadians react to a proposal to expand swaps to include offshore oil.

Chairman HUMPHREY. I'm eager to hear your comment on this.

Mr. RAICHT. It is somewhat difficult to tell in advance. Certainly the Canadians, when they originally approved the swap, specified U.S. domestic crude for security reasons. They feel very strongly that they would prefer to have U.S. domestic crude and I think it is important for us to use the facilities that we do have available and one of the problems we have had in terms of discussing expansion of the parameters of swaps with the Canadians is that we had a set of parameters already approved by both sides and no swaps approved. The NEB had approved them. As a matter of fact, I think of the seven that Mr. Zarb mentioned, five had been approved by the NEB and, if there was a delinquent in this case it was the U.S. side in approving those swaps.

But we recently approved three and that should start us, at least give us a firm ground on which to go to the Canadians and say, "We are doing our job and it now becomes necessary to take a look at whether those exchanges are sufficient to meet the needs of the Canadian-dependent refiners in the northern tier and what we can do to expand those parameters and whether it is possible and feasible for the Canadians in terms of their own national security and economic and political objectives to do that.

Chairman HUMPHREY. Do you know whether or not the Canadian Government has taken any firm position for or against offshore oil swaps? I understand what you said about the NEB, but speaking now of the political overtones, has there been any public utterance on the swaps of offshore oil?

Mr. RAICHT. Actually, the only thing we have at the present time is an order in council which was issued by the Canadian Cabinet when it originally approved the first three swaps, specifying U.S. domestic crude. We don't have anything beyond that and there have not been any political level statements from the Canadian Government indicating opposition to offshore swaps. However, in discussions that we had with the Canadians before any swaps were discussed or approved, the Canadians indicated to us fairly clearly that, at least in the first instance, swaps would have to involve U.S. domestic crude.

Chairman HUMPHREY. What sort of conditions might we be able to offer Canada—or under what conditions could they demand—that would make feasible or acceptable the proposals of offshore swaps?

Mr. RAICHT. I think it is somewhat difficult to tell what the Canadians would demand or what we would be prepared to offer at this point in time. We do intend to note to the Canadians, that we have begun using the existing facilities and in light of the emerging logistical constraints, there remains a short-term gap that needs to be filled. But I think it is premature to indicate at this point what we would be prepared to give and what they might be prepared to accept. I don't think you would conduct a negotiation that way where you put all of your cards on the table.

CHAIRMAN HUMPHREY. You have listened today and there will be more testimony as well. If we could get the time to hear from other people in this area as to the concern that we have over this gap during the time that the exports from Canada decline and phase out and the time that it would take to get the pipelines on station, you would realize the depths of our concern. That gap could have disastrous effects upon us—it must be filled.

I know that you will convey to the Department of State our concern on this matter. You were very active in this some 18 months ago as I recollect, so you have good credentials. Tell the Secretary, and I will do so as well, that I intend to have breakfast, lunch, and dinner with him over this subject. I have already talked with Mr. Kissinger about this, but, as the time to prepare for a severe winter runs out and we examine the Kitimat proposal which has just been endorsed here by our own State energy agency, my concern increases as to just whether or not we are going to be able to go on schedule—to phase in the pipeline bringing new sources of oil to the northern tier concurrently with the phaseout of Canadian exports. Therefore, we must have diligence on the part of our negotiating team, which is essentially the State Department and the Commerce Department, to pin this down.

Mr. RAICHT. We have recognized for some time that swaps would play and had to play a major role as Canadian exports were phased out. We recognized this quite some time ago and have been actively working on it.

I would think that one of the important things, though, in terms of assuring a cooperative attitude on the part of the Canadians and assuring that they can show some flexibility with regard to how swaps were arranged, that they have some guarantee that they are not opening up Pandora's box, that there is a long-term solution in line.

Chairman HUMPHREY. I agree with that.

Mr. RAICHT. The fact that the Kitimat pipeline people—and I don't mean by that to indicate in my view, at least, or the State Department's view that Kitimat line is better or worse than the northern tier line—I think we would have to rely on FEA's judgment on that. They are in a better position and have more competence and actually more analysts than we do. But a long-term solution is required, so that the Canadians have some assurance, I think, that there is going to be an end to the period during which they would be required to engage in exchanges. They have to have some assurance that the northern tier is going to have a long-term supply logistical facility in place, ready to go, as of a certain date.

Now, the Kitimat pipeline people have informed us that they intend to submit an application to the NEB by December of this year and, of course, we will have to await what the NEB hearings produce in terms of a decision or recommendation to the cabinet by the NEB but anticipating or assuming that the NEB does give approval of a Kitimat pipeline or a trans-Provincial pipeline, that would assure a long-term solution to the problem within a reasonable time frame, and I think the Canadians would then be more willing to consider short-term solutions that involve essentially expanded exports from Canada, although I am not sure we should count on swaps being able to expand exports.

Chairman HUMPHREY. Do you have anything else you would like to offer?

Mr. RAICHT. It seems to me absolutely vital, in terms of persuading the Canadian Government, to approve the use of offshore oil in swap arrangements that we have in place a long-term solution and are able to demonstrate convincingly that we have made full use of existing facilities.

For that reason, I am quite pleased, indeed, that we have approved the first three of the swap proposals that have been put forward.

You asked me earlier how I would judge the Canadian response and what might be the kinds of things we could offer and gain.

I indicated, you know, I don't think you want me, and I certainly don't want at this point, to engage in negotiation on what might be usable or what might be feasible in those terms and certainly there is a constraint, a political constraint, quite severe, in Canada because, obviously, any offshore swaps would mean backing Canadian oil out of Montreal refineries and the Canadians have made clear their commitment to see Canadian oil be used in those refineries to help diminish their own dependence on foreign sources of oil. I am not sure how excited they would be at the prospect of American firms acting as middlemen between them and foreign suppliers, but there may be some conditions under which they would be prepared to accept offshore swaps.

What the parameters of those swaps would be I think would depend entirely on how we are able to do in our discussions with the Canadians, but I don't want to leave you or any of the people of Minnesota in doubt that we recognize there is a problem and that we bear the primary responsibility in terms of discussing with the Canadians the ways of expanding the parameters, that during this gap period there is sufficient energy supply available for Minnesota and the rest of the northern tier states.

Chairman HUMPHREY. One alternative, and I don't know if it is feasible, is to have a contractual arrangement with Canada wherein during the period of transition to the new pipeline structure, which would provide us long-range adequacy of supply, we would ask Canada to alter their export phaseout in exchange for a commitment to deliver Alaskan oil upon completion of the pipeline. In other words, let's assume that we were able to obtain a commitment from the Canadians wherein they would not phase out on the current schedule, in 1978, 1979 or 1980. Instead, they would maintain a higher level of export petroleum to us and it would be a draw, so to speak, on the availability of Alaska oil, at such time as Alaska oil comes through the line and is ready to be commercially used. That's one possibility that would alleviate dependence on Saudi Arabian or Venezuelan oil, serving both United States and Canadian interests.

Mr. RAICHT. Senator, we have discussed this informally with a number of Canadian officials. What you are describing are essentially time swaps. They have not been particularly excited at the idea of time swaps, although they haven't excluded them. I think we should explore this as one possibility, but I don't hold very much hope, really, that the Canadians would be willing to go for anything like that. There are problems in the compatability of Alaskan oil and their refineries. There are a number of others, pricing and so forth, and I just don't think they would be prepared to go that route. However, that certainly is one avenue without discounting it in advance, I think we need to explore with the Canadians.

Chairman HUMPHREY. Thank you very much. I regret we do not have more time with you, but we have to move along. Barring objection, your prepared statement will be placed in the hearing record.

[The prepared statement of Mr. Raicht follows:]

PREPARED STATEMENT OF HON. LAWRENCE R. RAICHT

I welcome this opportunity to discuss with you today energy prospects over the next several years for the Northern Tier states.

I will first provide a brief, general assessment of oil and gas availability over the next several years but I will focus on the oil supply situation, particularly in the short term.

The outlook for the availability of Canadian oil and natural gas during the coming winter season is slightly improved over previous estimates. No curtailments of natural gas imports from Canada are expected during the 1976/77 winter season. In recent discussions with senior Canadian officials we were advised that domestic demand and supply conditions for natural gas in Canada have improved significantly. As a result, assuming normal weather, Canada does not anticipate any curtailments of natural gas exports to the United States during the winter heating season.

A parallel situation exists with regard to crude oil. Because of the delay in the operation of the Sarnia-Montreal pipelines, exports of crude oil during 1976 are likely to be higher than originally anticipated, and the allowable export level is not expected to fall to 380,000 B/D until the fourth quarter of this year. Under the preferential allocation plan which FEA has established, this will ensure continued supply of crude oil feedstocks from Canada to Priority One refineries—those with no access to alternative supplies—until the end of 1976.

On January 1, 1977, exports from Canada are scheduled to drop to 255,000 B/D. This is approximately the minimum level of requirements for Priority One refineries in the Northern Tier. However, even this level is not certain. It may be above or below 255,000 B/D. The Canadian National Energy Board has scheduled hearings on Canada's crude oil supply/demand situation in October. As a result of permissible exports to the U.S. for 1977 and beyond, and adjust the phase out schedule accordingly.

Since Canada announced its intention to phase out exports of crude oil late in 1974, we have been concerned about the adverse impact this would have on the oil supply outlook for the Northern Tier states. With other agencies, we have been actively engaged in examining supply alternatives in both the short and long term. Recognizing the role that crude oil exchanges could play, the Department of State and FEA proposed to Canada in 1975 a joint examination of such arrangements. I believe you were provided with a copy of the report of the joint US-Canadian working group, which studied this question, during your hearings last year.

It is clear that in a fundamental sense, alternative supply arrangements are the responsibility of U.S. industry and will require the construction of new facilities. Both the U.S. and Canadian Governments can facilitate the adjustment and have agreed to do so. A number of possibilities have been suggested including expansion of the Williams Brothers Pipeline system to move crude oil north from the Gulf of Mexico, the Kitimat Pipeline from the coast of British Colombia to Edmonton in Alberta where it would connect with existing facilities now being used to supply Northern Tier industry and the Northern Tier pipeline from the Puget Sound to Clearbrook, Minnesota. FEA has conducted a detailed study of alternative supply arrangements in response to a request from Congress. However, even if one or more of these possibilities do materialize, they will only begin to help in the longer term. The problem that we face now is assuring adequate oil supplies to these Canadian dependent refineries during the interim, before permanent supply alternatives come on stream.

We have examined the possibilities and have concluded that exchanges with Canada can play a significant role over the next several years. It should be understood that Canada has made unmistakably clear its intention to conserve its dwindling energy resources. The Canadian objective is a legitimate one. Indeed the US is pursuing a similar policy. Thus Canada is unlikely to agree to any proposal which accelerates its dependence on imported oil.

As you know, the understanding between the U.S. and Canada to facilitate exchanges has seen results. Both countries have now approved three exchanges, and these arrangements should help to alleviate the impact of the phase-out of exports by Canada on Northern Tier refineries until alternative supply facilities become available.

However, in approving these first three exchanges, Canada indicated that it was only prepared to accept domestic US crude oil. While the Canadian concern for security of supply is understandable, Canada's insistence on domestic U.S. crude has created a number of problems which limit the extent to which exchange arrangements can help the short-term needs of Northern Tier industry. A number of constraints have already become apparent: logistical bottlenecks in moving domestic US crude—we now estimate that this requirement could limit exchanges to about 50,000 B/D; this same pipeline capacity is also needed to meet the supply requirements of non-Priority One refineries, etc.

We have been exploring alternative arrangements for such exchanges which would involve the use of off-shore sources and expect to begin discussions with Canada shortly on how we might agree to widen the parameters for exchanges.

Canada has been cooperative with the U.S. in working with us to alleviate the impact of its decision to gradually phase-out oil exports to the U.S. It is likely, however that the Canadians will want to examine several factors very closely before agreeing to more flexible exchange arrangements. Two of the most important factors are:

(1) Action in the U.S.—primarily by the industry—toward development of a long-term solution to ensure adequate crude oil supplies, and

(2) The extent to which US industry is taking advantage of existing alternative supply possibilities.

The Department of State stands ready to help with both short and long term solutions to the energy needs of the Northern Tier. If industry can agree on a long term solution, we believe the chances for working out a short term solution with Canada will be substantially improved.

Chairman HUMPHREY. Our next witness is Mr. Vernon T. Jones, president of the Williams Pipeline Co., subsidiary of the Williams Cos., which is headquartered in Tulsa, Okla.

## STATEMENT OF VERNON T. JONES, PRESIDENT, THE WILLIAMS PIPELINE CO., TULSA, OKLA.

Mr. JONES. Thank you, Mr. Chairman. We are very happy to have the opportunity to appear in these hearings.

In the interest of time, I think it would be just as well if we moved to chart 3 of my prepared statement. Chart 3 is a map of our pipeline. Now, to describe Williams' position with respect to the crude supply situation into the Twin Cities and upper Minnesota.

In mid-1974 Williams Pipeline Co. converted part of its system from mid-Kansas up to the Twin Cities to develop the ability to batch crude in its pipe, products pipeline system and since that time has been moving in the order of 20,000 to as much as 30,000 barrels per day up that route into the Twin Cities area.

With the crude shortfall developing, our analysis of the situation for the coming winter season is shown on chart 3, overlay 1. We decided that we needed to have more capacity into this area for this coming winter. Our analysis would be indicating that there could be, with a severe winter, a shortfall of both crude oil and refined products in the general Minnesota market of as much as 90,000 barrels per day. Tempering that by the anticipated Canadian crude swaps, by the fact that there will probably not be a severe winter, although there may be again a normal winter and other factors, we bring this back to a possible shortfall within the order of 50,000 barrels per day. That could occur in most of January and February of this year.

We are installing at the present time horsepower on the northwest leg of our system that will allow us to develop up to an additional 20,000 barrels per day beginning January 1 into this area which can be used for either crude oil or refined products. This certainly doesn't solve the problem, but it is the maximum response that we can offer since we happen to have some equipment in our warehouses that have been purchased a number of years ago in anticipation of this very expansion which was then shelved and some other factors that come into our favor as far as timing is concerned.

Our crude oil expansion that we have announced involves station expansion represented by the dots on chart 3, overlay 2, that are on the line sections down in Oklahoma and Kansas and then this line section going up to Mason City in Iowa. This is where we are adding horsepower and new stations.

We will be adding a new 18-inch line between Mason City, Iowa, and the Twin Cities area to directly connect the Twin Cities refineries. We also have tentative plans to put in a nominal expansion on our facilities north of the Twin Cities. This would be additional horsepower to our existing system. This would allow us to move perhaps as much as 10,000 barrels per day of crude oil north of the Twin Cities to the refineries in the Wrenshall-Superior areas.

Chart 3, overlay 3, shows the capability of the addition of horsepower on our 16-inch system to raise our crude oil capacity in the Twin Cities up to about 130,000 barrels per day maximum.

Chairman HUMPHREY. What is it presently?

Mr. JONES. We have a maximum of 30,000 barrels per day, the first step that we are committed to and that will be operating October 1, 1977, is the 80,000-barrel a day expansion.

This next step, which would require about a year's leadtime as far as the additional horsepower is concerned from the decision date to completion would move that capacity from 80,000 barrels a day up to a maximum of 130,000 barrels per day.

Chart 3, overlay 4, shows that our ultimate capability with respect to supplying crude into the Minnesota refineries would be the construction of a 24-inch line in Cushing, Okla., or Tulsa origins to Mason City to connect into the 18-inch line that we are now going to construct. This would give us the capability of putting up 300,000 barrels per day of crude oil into the Twin Cities area.

Chairman HUMPHREY. What is the time schedule for this proposed line, Mr. Jones?

Mr. JONES. That would require probably about 18 months loadtime from the decision but, since we would be traversing basically our own pipeline corridors, I think that we could comfortably stay within that time frame.

I might comment with respect to the alternatives as we view them and some of the processes we have gone through in deciding to go ahead with our interim expension. From a time standpoint, we feel that the earliest one of the lines, either the northern tier or Kitimat line, could be operating would be 1980. I think it is unlikely that you could get one in operation much ahead of that.

We feel that our own role is at least one of supplementing the crude supply into the Twin Cities refineries to the extent of our capacity and then it may be a diminishing role and we will be in the position of providing supplemental crude supply in addition to that coming from the alternatives such as the Kitimat line, and there we would be using the excess capacity to cover our requirements for hauling refined products into this market area.

We also feel it is very logical for either the Cushing-Tulsa area to be built or for a new line to be built from the Twin Cities over to the Wood River-Patoka area in Illinois to connect into the CAP line system.

These are lines that can be constructed for a cost on the order of $100 to $150 million. They are within the United States. They are not traversing environmentally sensitive areas. They are going through areas where there are existing pipelines. They traverse States where the pipelines have rights of eminent domain and their cost is, of course, only a fraction of what you would have for something like the northern tier.

However, the Kitimat line is less expensive. It seems to us that probably a combination of these systems is the best response, rather than to rely on the system that is built to move Alaskan crude into an area that has a limited ability to refine that crude, and the Alaskan crude can probably find other markets, logical markets, on the Texas-Louisiana gulf coast where they could displace the other crudes backup into the northern tier refineries. That would be a logical component of the crude slate for those plants as they now stand. We think there may very well be some expansions of the refining capacity in this area; we feel, however, to a limited extent.

Chairman HUMPHREY. I think that the general public has the impression that all crude is alike.

Mr. JONES. There are vast differences.

Chairman HUMPHREY. Of course there are.

You mentioned Alaskan crude, adaptability, or lack thereof, to our refineries in this area. Would you like to give any further comment on that?

Mr. JONES. Based on that, our conversation with the refiners themselves, you have a plant here that could run it. We are not certain of the precise figures, but the other plants can run far less than 50 percent of Alaskan crude. It is high sulfur, relatively heavy crude, and it is not particularly attractive for this present refining center with the exception of one refinery.

Chairman HUMPHREY. Would you say it is a polluting crude as well?

Mr. JONES. It certainly has high sulfur content. There had been necessarily desulfurization of some form that would have to be attendant to the processing of this crude oil.

Chairman HUMPHREY. Your present intention now is to connect the Mason City line to the Twin Cities.

Mr. JONES. That's correct.

Chairman HUMPHREY. Will that be completed in October 1977?

Mr. JONES. We will have that completed by October of 1977. The particular item that was on our critical path from a time standpoint was our pumps. We have a supplier who is going to be able to deliver these much sooner than we originally expected.

Chairman HUMPHREY. What will that yield in terms of barrels per day?

Mr. JONES. 80,000 barrels per day of capacity into the Twin Cities area.

Chairman HUMPHREY. How much additional oil does that amount to over present capacity?

Mr. JONES. That's 50,000 to 60,000 barrels per day.

Chairman HUMPHREY. Over present?

Mr. JONES. Over our present capabilities.

Chairman HUMPHREY. Do you feel that supply will fill in any gap for 1977?

Mr. JONES. In all probability, this would cover the gap for the last quarter of 1977 and the first quarter of 1978. This is again, assuming normal winter conditions.

Chairman HUMPHREY. Can you make any predictions regarding oil availability next winter?

Mr. JONES. Our delivery capability will be well below the requirement if the present schedule for the Canadian export curtailments is followed.

Chairman HUMPHREY. That's in the winter of 1978?

Mr. JONES. 1977–78.

Chairman HUMPHREY. All right, Mr. Jones. I understand that you had plans for an even larger expansion at a later date, is that correct?

Mr. JONES. We have the capability of building the 24-inch line from Cushing, Okla., and Tulsa where it would connect with the Seaway and Texoma pipelines that come from the Texas gulf coast area into Cushing, crude oil lines, and to the Explorer pipeline system that comes from the Texas-Louisiana gulf coast area into Tulsa and is currently hauling crude oil in addition to refined products.

We feel this would give us origins that are connected not only to domestic crude sources but other pipelines that move crude from west Texas and Oklahoma, but also from offshore unloading facilities to readily move imported crudes at very competitive and reasonable tariffs through facilities that are in existence. There is no doubt, they are ready to operate.

Chairman HUMPHREY. Mr. Jones, we are very grateful to you. Our time constraints impede my questioning you any further, but I want to thank you for the reassuring statement you have given to us and for the cooperation you have extended in this development between now and October 1977. This is going to be very helpful for this part of the country, and we are grateful to you, sir. Thank you very much.

Mr. JONES. We would like to submit our prepared statement for the record.

Chairman HUMPHREY. The record will be kept open for 2 weeks and your prepared statement will be included in the record. Thank you very much, Mr. Jones.

[The prepared statement of Mr. Jones follows:]

PREPARED STATEMENT OF VERNON T. JONES

Thank you. My name is Vernon T. Jones, president and chief executive officer of Williams Pipe Line Company, subsidiary of The Williams Companies which is headquartered in Tulsa, Okla.

As you are no doubt aware, the crude supply problem facing the Northern Tier today results from the Canadian Government's announced plans to systematically phase out Canadian crude oil exports to the U.S. by 1982. Chart I compares actual 1974 and 1975 Canadian exports to the U.S. with the Canadian Government's latest export forecast. The rapid curtailment of this crude supply source to the U.S. signifies the urgency with which historically dependent U.S. refiners must develop alternative means of supply. While many U.S. refineries presently running Canadian crude have access to available supply alternatives, several Northern Tier refiners are faced with no immediate alternative means of supply to replace the resulting deficit.

These refineries, located in Minnesota, Wisconsin, Michigan, North Dakota, and Montana, have been designated first priority recipients of the remaining Canadian crude exports under the FEA's allocation program. The eleven Priority I refineries in these states have a total crude capacity of approximately 487M BPD, and in 1975, Canadian crude comprised some 49.8 percent of their total supply. This program provides these refineries currently with a priority allocation of approximately 264M BPD. Current exports in excess of this level are shared among all other historic users, classified Priority II, on the basis of past Canadian dependence.

Beginning in 1977 and thereafter, all Priority II allocations will be phased out completely, and Priority I refineries will be faced with shortages of Canadian crude necessary to sustain present operating levels. Compounding this problem, increases in petroleum products demand and anticipated decreases in local domestic crude production contribute to the severity of the overall supply situation in the Northern Tier. Williams Pipe Line's estimate of the shortages in our Northern market area alone (Minnesota, Wisconsin and North Dakota) is shown on Chart 2. This line indicates the refining capacity of the four Priority I refineries directly connected to Williams Pipe Line System. These four include the Koch and Ashland refineries in the Twin Cities area and the Continental and Murphy refineries located in the Duluth-Superior area. The refineries have an approximate capacity of 262M BPD and a normal crude run level of about 228M BPD. This line represents total Canadian crude oil exports to the U.S.; and the bottom line indicates WPL's estimate of the impact of export reductions on these four refineries. These refineries are the only ones located in the Minnesota/Wisconsin area, and as a group, they are the most heavily dependent upon Canadian crude oil. In fact, these four plants receive approximately 63 percent of the present total Priority I allocation of 264M BPD. The dramatic increase in anticipated crude oil deficits in this area, again, points out the need for quick action.

While several long-term solutions have been proposed, it is our contention that a very serious short-term problem will exist beginning as early as January, 1977, long before any of the proposed permanent transportation solutions could become operational. In 1974, Williams Pipe Line modified one 12'' line in its existing system in order to batch limited amounts of crude oil in conventional refined products shipments from the Kansas/Oklahoma area to the Koch refinery at Pine Bend. Subsequently, an additional delivery connection to the Ashland refinery at South St. Paul Park was completed. To date, Williams has delivered over 4.5MM Bbls. of crude to the Twin Cities area. However, considering the magnitude of future shortages of Canadian crude, additional steps must be taken. Consequently, in July of this year, Williams began construction to increase refined products capacity to the Northern Tier by 20M BPD. This expansion is scheduled for completion by January 1, 1977. Additionally, in August, WPL announced plans for a major expansion of our existing system. This project, in conjunction with the initial 20M BPD expansion, will provide up to 80M BPD of crude oil and/or products capacity to the Minneapolis area by October, 1977. This expansion has been timed to meet the forecast deficits in Canadian crude oil exports for 1978—and I feel safe in saying, no other company can provide this service. Presently, all pumping units are on order for this expansion, and the necessary right-of-way acquisition has begun. Bid invitations for the 18'' pipe will be mailed out next week, and a field office is already in place on the construction site. Williams' existing permit in the state of Iowa has been updated, and steps required for permit application in Minnesota are well underway. Actual construction is scheduled to begin in the Spring of 1977.

In addition to WPL's capabilities to meet the Northern Tier market shortages, several other short-term solutions are available. These would include a temporary relaxation in Canadian Government export policy, U.S.-Canadian exchanges, supplemental products and/or crude supplied off of the river and the Great Lakes, and possibly even unit trains carrying crude from the West Coast to existing pipeline distribution points in the Northern Tier. Only the first two, however, are felt to represent realistic alternatives that would provide any substantial relief to the affected refiners.

(1) Relaxation of Canadian Policy.—Although a total reversal is unlikely, there may be some modification to adjust to existing conditions. The heavier asphaltic crudes could be available indefinitely, free of any quota or allocation system. At the present time, however, heavy crudes and condensates are included in the allocation system. Recent information from the FEA and oil companies emphasize the feeling that Canada intends to take a hard line.

(2) U.S./Canadian Exchanges.—U.S. crude exchanges in small quantities for Canadian crude has been approved by both governments for Murphy and Koch. Others have applications pending. These trades would be free from import quotas. It is not likely that additional exchanges will be approved, and those now in effect will be terminated in the near future. The Canadian government approval of exchanges is presently limited to U.S. domestic crudes only, and Canada is reluctant to allow trades of Canadian crudes for U.S. imported material.

Williams Pipe Line's current expansion—which has been undertaken without any throughput guarantees—comprises the first phase of Williams' planned four step construction program to provide additional crude oil and/or refined products capacity to the central Northern Tier states. This initial step (Phase I) is compatible with any of the major long-term systems now under consideration.

Chart 3, overlay 1 shows the phase I expansion which includes construction of approximately 123 miles of an 18'' line from Mason City, Iowa, to Minneapolis, as well as horsepower expansions on the present system. This will enable the dedication of an existing 12'' line to crude service south of Mason City. This step accesses crude supply sources including Texas, Gulf Coast, Mid-Continent and imported crude oils. Additional expansion of existing lines is also required to accomodate refined products volume that is displaced by the dedicated crude oil system. The estimated cost for Phase I is approximately $20MM.

In Phase II, shown on Chart 3, overlay 2, WPL proposes the addition of necessary power to enable movement of crude volume from the dedicated 12'' system to a 16'' system, which will increase capacity from 80M BPD to approximately 120M BPD. Facilities required under Phase II include an additional fourteen pumping units requiring a total of 34 thousand installed horsepower, approximately 29 miles of new 8'' line construction, and an additional 200,000 Bbls. of tankage on the system.

Phase III, shown in Chart 3, overlay 3, shows that Williams Pipe Line plans to build, if necessary, a pipeline from Cushing, Oklahoma, to either Tulsa or Barnsdall, Oklahoma. In all likelihood, this expansion would be made in conjunction with or after Phase II is constructed, although it could be done at any point in our overall program. This line is predicated on the continued ability of other existing pipeline carriers or potential future carriers to provide the necessary link between the many crude lines converging at Cushing and the origin point of WPL's 12'' or 16'' crude systems.

Phase IV, on Chart 3, overlay 4, is the final step in which Williams Pipe Line proposes to construct a 24'' line to complete the Cushing, Oklahoma, to Minneapolis system. This system will have the capability of pumping up to 350M BPD to the Northern Tier States. It would be constructed over 95% on existing pipeline R/W and on existing station sites with minimum environmental impact. The investment for the line will be between 100 and 125 million dollars, all to be spent within the U.S. Considerable discussion concerning how the Williams Pipe Line proposal will not totally solve the Northern Tier problem has resulted and it should be noted that Williams Pipe Line Company does not maintain that its proposal represents the solution in entirety but will require additional steps by others. However, expansion of the Williams system would satisfy the needs of the Minneapolis/Wisconsin refineries whose dependence represents 63% of the total refining capacity presently without an alternate supply system. Moreover, through reversal of the Minnesota and Portal pipelines, Williams could supply the North Dakota shortfall. However, economics would probably dictate that indigenous North Dakota and Montana crudes, which are presently exported, be directed through existing lines to the local refineries. Expansion of existing systems to Chicago, restriction of crude oil produced and products refined in certain states to the immediate area, and separate and distinct solutions in the state of Washington in conjunction with the Williams proposal will provide a more economical solution to the problem than many proposed.

Chart 4 shows several other long-range solutions that have been proposed to alleviate the Northern Tier problem. At this point, it appears that the most viable alternatives proposed may be classified into two broad categories:

1. One group involves the movement of Alaskan and imported crudes from the West Coast into the Northern Tier.
2. The other group involves the movement of domestic and imported crude oils from the Gulf Coast into the Northern Tier.

The West Coast group would include the proposed Transprovincial Pipeline system, the proposed Northern Tier Pipeline system, and the Sohio Pipeline project. Both the Transprovincial and Northern Tier pipeline proposals would provide direct solutions to the Northern Tier and would invlove Canadian or northern U.S. routings. The Sohio project, on the other hand, would provide a pipeline outlet for surplus Alaskan crude via a southern U.S. routing, which would link up with existing pipeline systems that supply refineries on the Gulf Coast, Mid-Continent, and lower Great Lakes areas. The Sohio project's impact on the Northern Tier area would primarily be to displace crudes presently being utilized on the Gulf Coast, thereby making this supply available for transportation to Northern Tier area. In this respect, the Sohio project may be considered complementary to the proposed Gulf Coast routings.

One of the proposed Gulf Coast routings would involve movement of crude oil from the Houston area via Explorer, Texoma, and Seaway pipelines to the Cushing, Oklahoma area. From Cushing, the Williams pipeline system expansion previously outlined would provide access to the Northern Tier.

The other Gulf Coast proposal would involve movement of crude oil from the St. James, Louisiana area via Capline pipeline system to Patoka, Illinois, near St. Louis. This would require a major expansion of the Capline system to provide adequate capacity. From St. Louis, existing pipeline networks would supply the Chicago area, and a new pipeline would be laid from the Minneapolis area to Patoka to provide access to the central Northern Tier States.

It is impossible in the short interval of time available today to discuss in detail the pros and cons of each individually proposed solution to the Northern Tier problem. All of the different alternatives proposed have shortcomings. I feel, however, that certain aspects of the Northern Tier problem must be understood in order to adequately evaluate the dimensions of the proposed solutions.

(1) First, the Northern Tier problem is one of transportation and not of supply. By that I mean, Northern Tier refiners are primarily concerned with finding the most economical means of transporting the types of crudes required to replace the predominately light, sweet Canadian crudes now used to run their refineries.

(2) The proposed Northern Tier P.L. and the Transprovincial P.L. appear to represent the most economical means of transporting Alaskan crude to the Northern Tier refineries—but these refineries have only a limited ability to run the heavy, high sulfur Alaskan crude unless extensive modifications are made. Therefore, these proposed pipelines would be heavily dependent on imported light crudes for their throughput.

(3) Economics indicate a wider variety of these light imported crudes would be available for movement from Gulf Coast origins and thence via WPL at competitive laid-in costs to the Northern Tier. Moreover, a greater number of established and proposed transportation systems would be available for movement of these crudes and potentially Alaskan crudes via the proposed Sohio route. Additionally, and of particular importance, WPL would provide access to Mid-Continent, Texas, and Gulf Coast domestic crudes which is not the case with the proposed Northern systems.

(4) Finally, WPL's proposed transportation system to link the Gulf Coast with the central Northern Tier could be operational sooner than any alternatives proposed to date. Because of Williams' ability to capitalize on the spare capacity in its system, its stepped expansion program can provide the necessary throughput with comparatively lower investment to furnish the central Northern Tier refineries with the necessary crude in time. Whereas all phases of Williams expansion program can be operational by late 1978 or early 1979, we do not feel that the other proposed solutions could be in place prior to late 1980 or early 1981.

In summary, it is our contention that the ultimate solution will be made up of a combination of part or several of the alternatives presently proposed. We do firmly believe, that Williams Pipe Line offers the only short-term solution to the supply problem in the Northern Tier.

Moreover, when a careful comparison of the types of crude oil and realistic costs of transportation facilities available from the Gulf and West Coast is made, we feel that our proposal to connect the Gulf Coast crude lines that presently end at Cushing and Tulsa to the Minnesota, Wisconsin and possibly North Dakota refineries represents one of the "economic" steps in the overall solution to the Northern Tier problem.

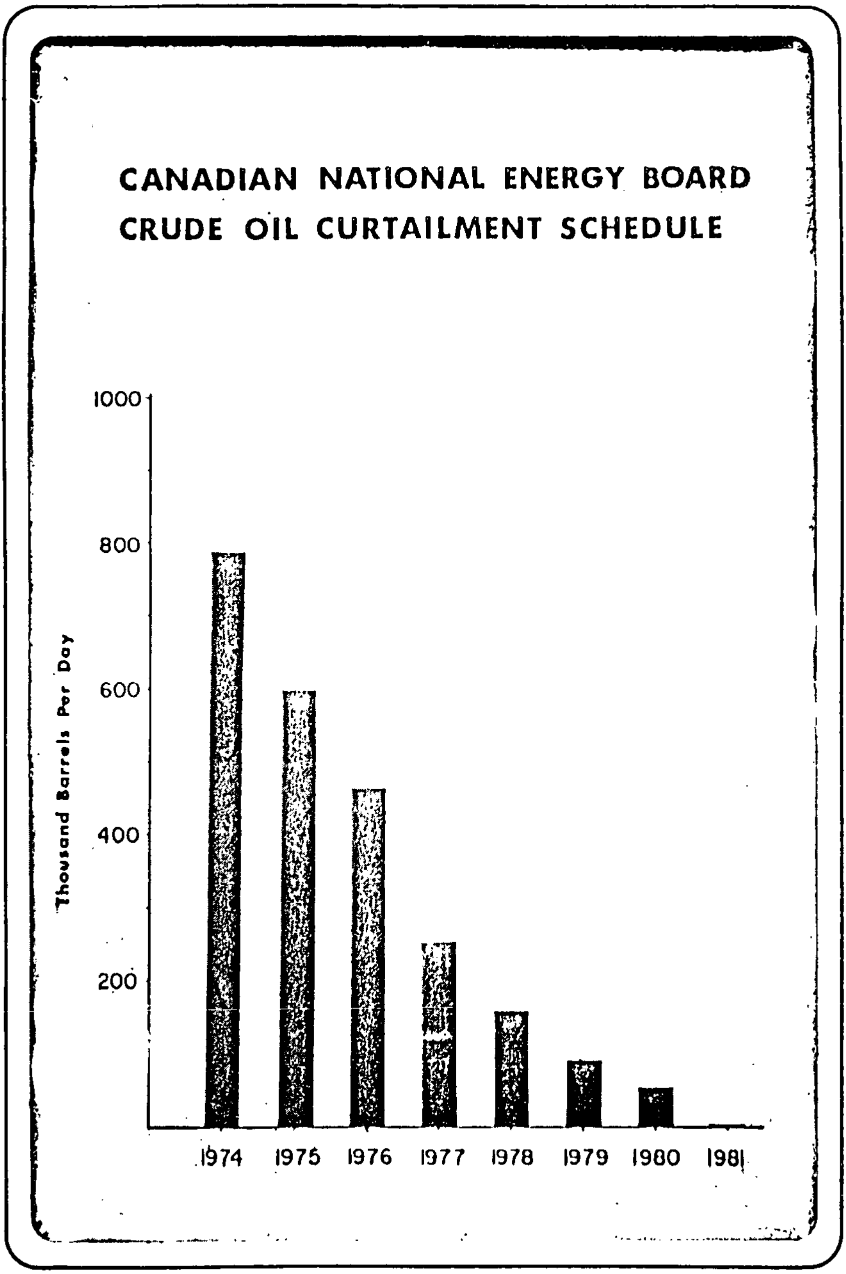

CANADIAN NATIONAL ENERGY BOARD
CRUDE OIL CURTAILMENT SCHEDULE
Thousand Barrels Per Day
1000
800
600
400
200
1974
1975
1976
1977
1978
1979
1980
1981

CHART 1

NORTHERN TIER CRUDE SUPPLY PROJECTION

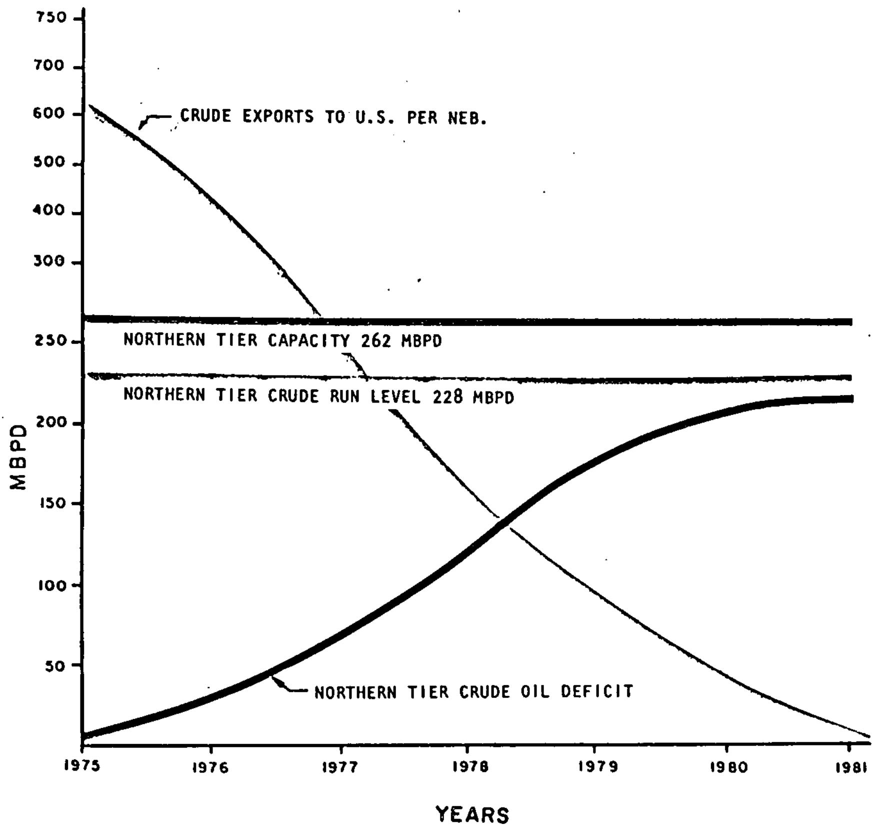



CHART 2

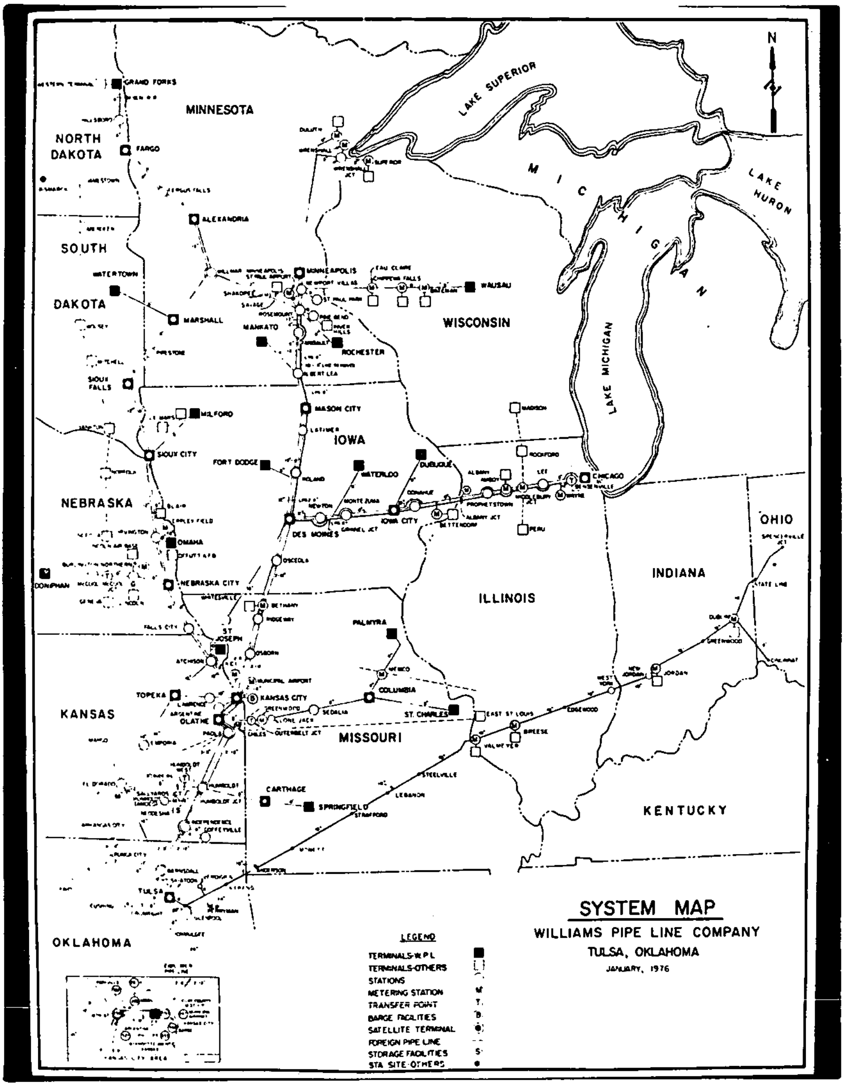

SYSTEM MAP
WILLIAMS PIPE LINE COMPANY
TULSA, OKLAHOMA
JANUARY, 1976
LEGEND
TERMINALS-W.P.L.
TERMINALS-OTHERS
STATIONS
METERING STATION
TRANSFER POINT
BARGE FACILITIES
SATELLITE TERMINAL
FOREIGN PIPE LINE
STORAGE FACILITIES
STA. SITE-OTHERS
NORTH DAKOTA
SOUTH DAKOTA
MINNESOTA
WISCONSIN
IOWA
NEBRASKA
KANSAS
MISSOURI
ILLINOIS
INDIANA
OHIO
KENTUCKY
OKLAHOMA
LAKE SUPERIOR
MICHIGAN
LAKE MICHIGAN
LAKE HURON
GRAND FORKS
FARGO
ALEXANDRIA
MINNEAPOLIS
WAUSAU
MARSHALL
MANKATO
ROCHESTER
MASON CITY
MILFORD
SIOUX CITY
FORT DODGE
WATERLOO
DUBUQUE
CHICAGO
DES MOINES
IOWA CITY
OMAHA
NEBRASKA CITY
PALMYRA
KANSAS CITY
COLUMBIA
ST. CHARLES
TOPEKA
OLATHE
CARTHAGE
SPRINGFIELD
TULSA
WATERTOWN
N

Chart 3

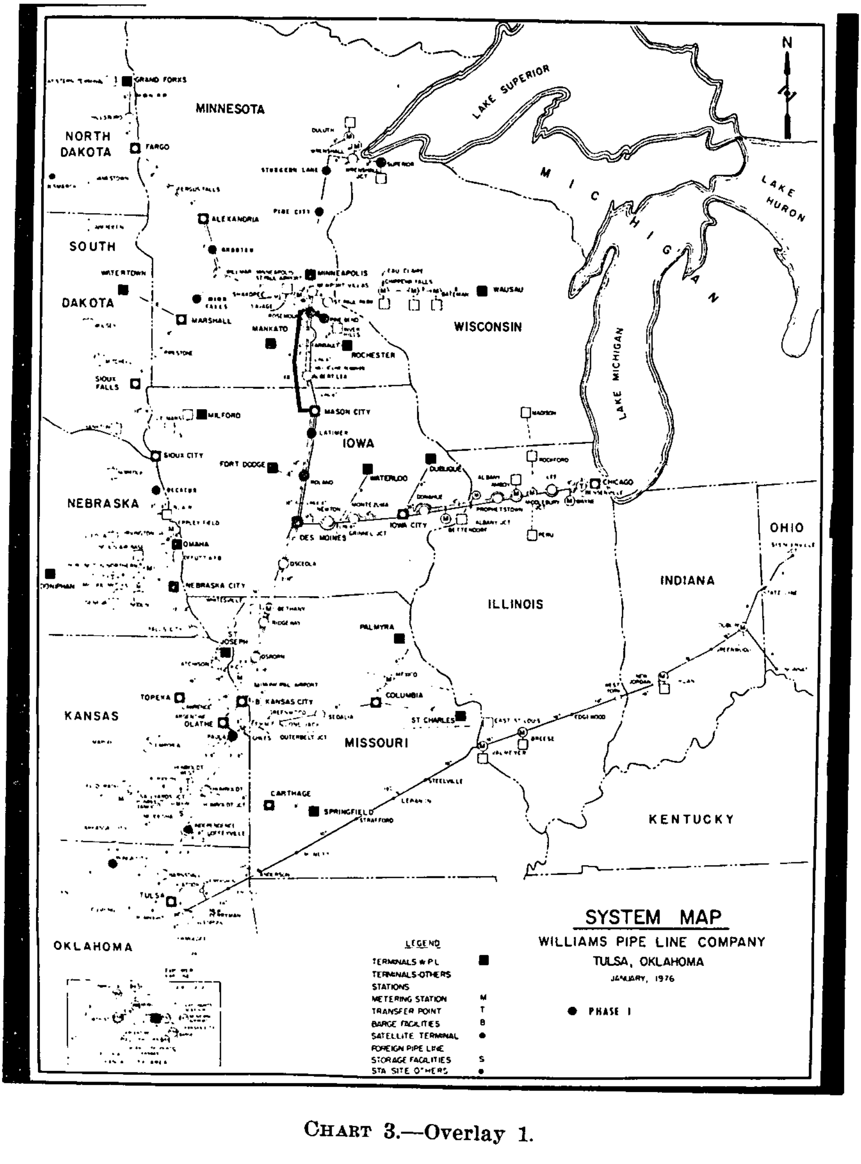



CHART 3.—Overlay 1.

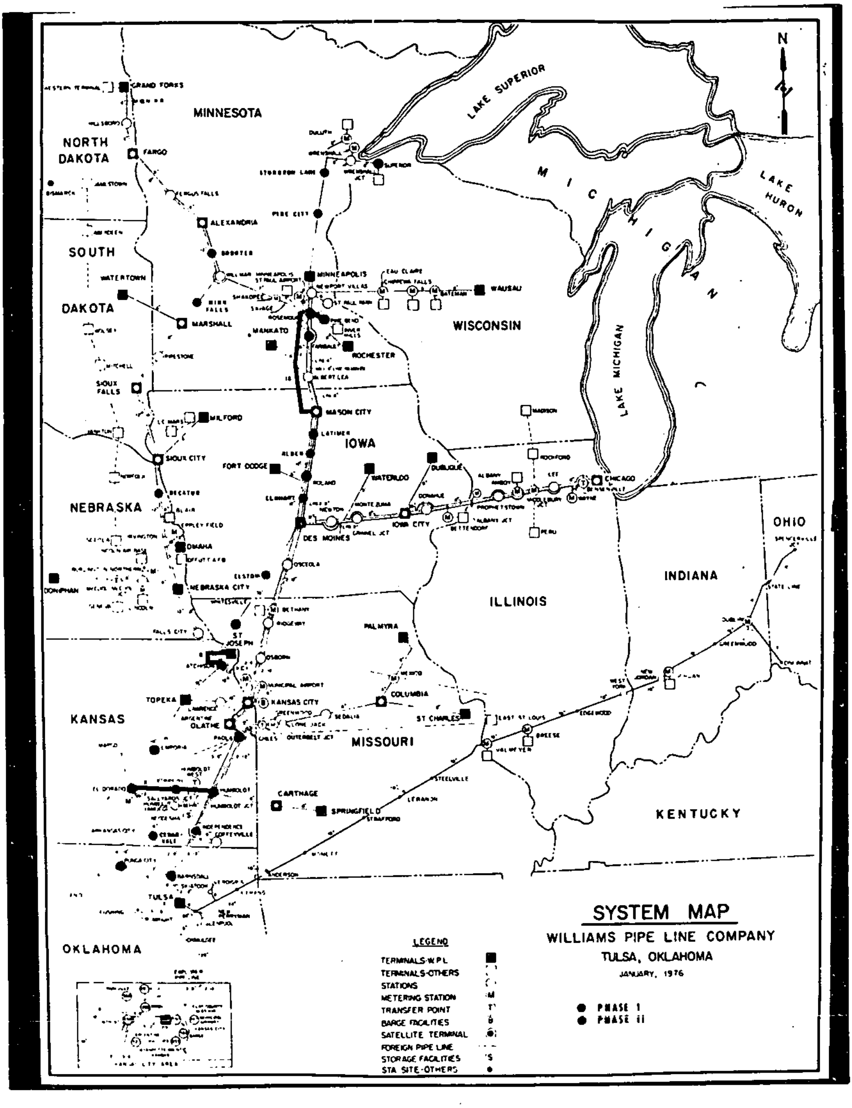



CHART 3.—Overlay 2.

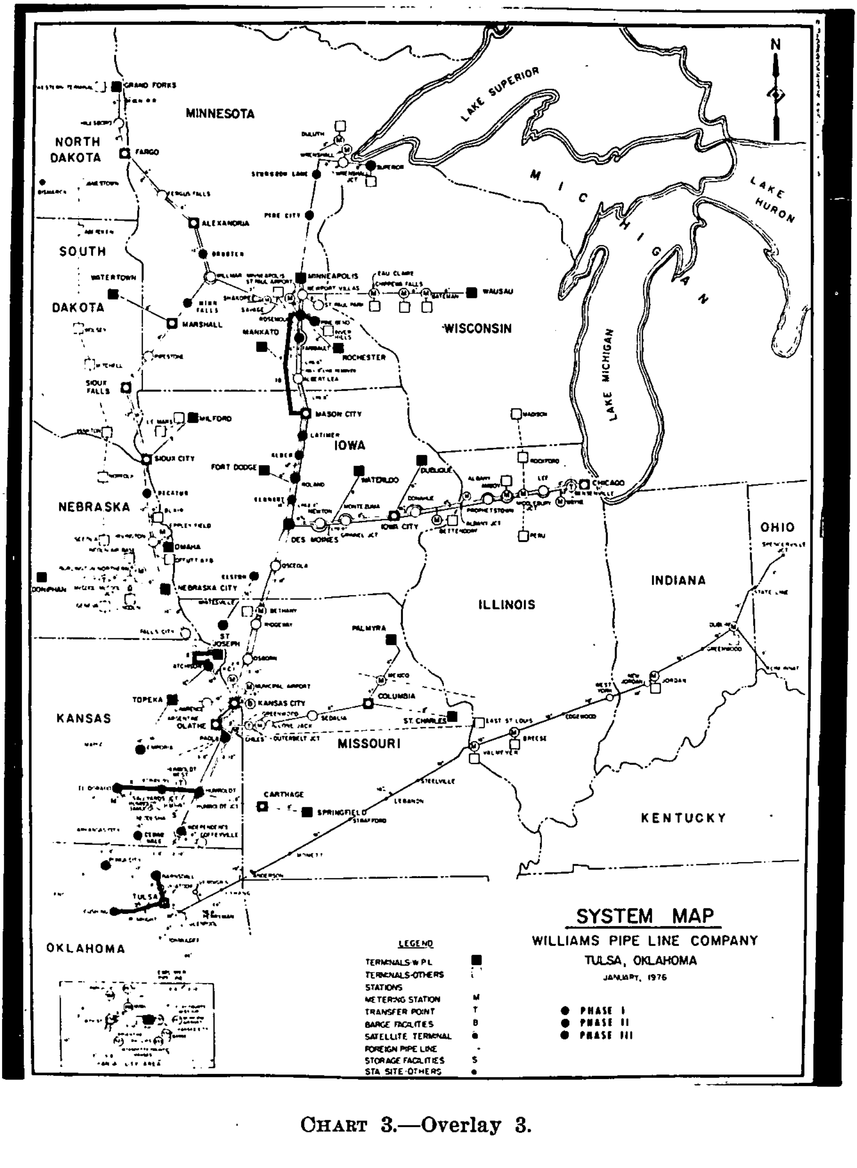



CHART 3.—Overlay 3.

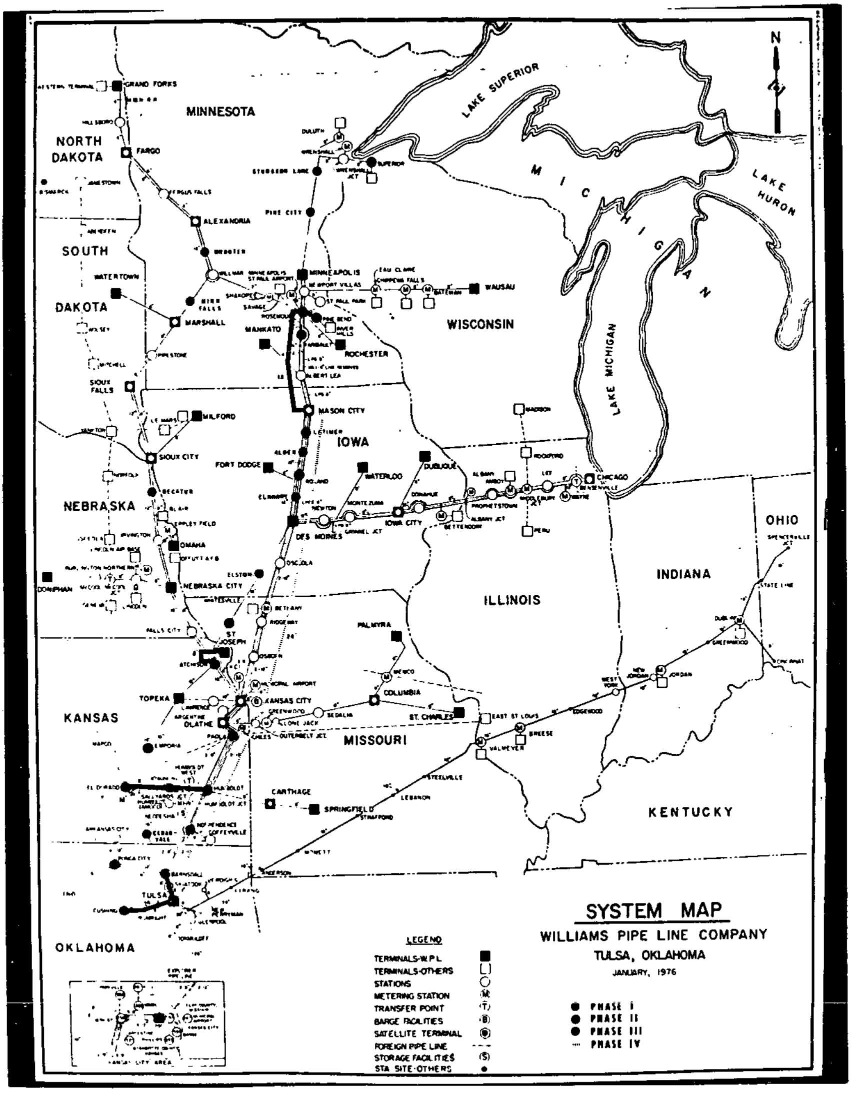



CHART 3.—Overlay 4.

# NORTHERN TIER ALTERNATE PIPELINE PROPOSALS

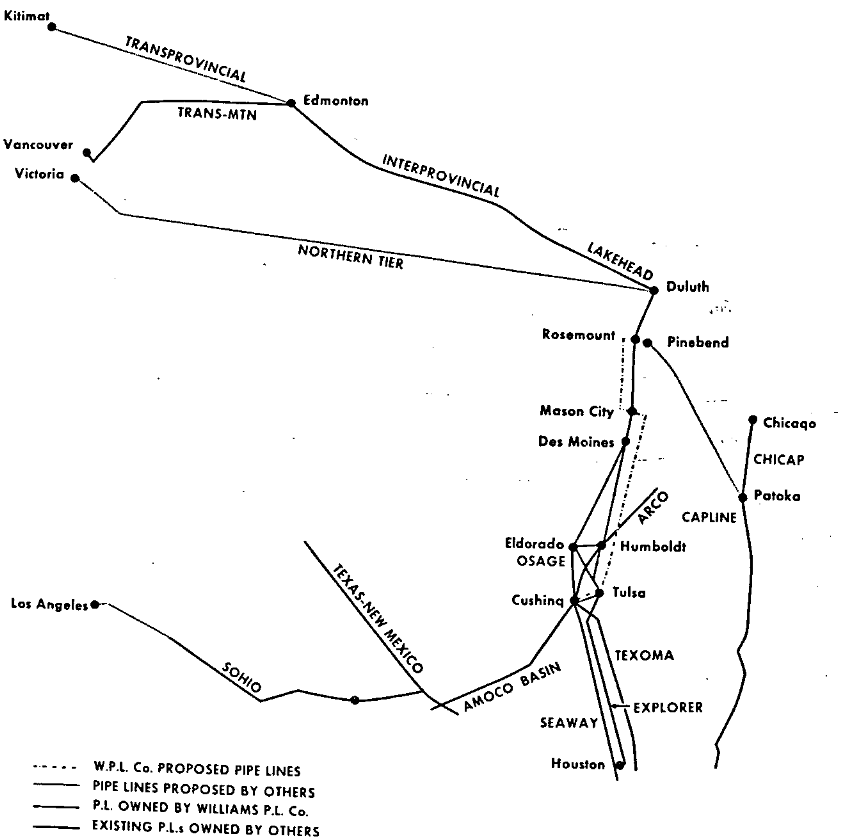



CHART 4

Chairman HUMPHREY. Mr. George Thiss.

Mr. Thiss, before you testify, I understand that Kitimat Pipe Line Group had a statement they wanted to submit for the record. We will place that statement in the record at this point.

[The statement of Mr. John R. Hall on behalf of Kitimat Pipe Line Group follows:]

STATEMENT OF JOHN R. HALL ON BEHALF OF THE KITIMAT PIPE LINE GROUP

My name is John R. Hall and I am Executive Vice President of Ashland Oil, Inc. Our company operates a modern 65,000 B/D refinery in St. Paul Park, Minnesota. My testimony today is on behalf of the Kitimat Pipe Line. There are currently eight participants in the Kitimat Pipe Line, six of whom are Northern Tier refiners, and two of whom are Canadian pipeline companies. The six refiners in our group include Koch, Ashland, and Continental who operate refineries in Minnesota, Murphy Oil who operates a refinery in Wisconsin, Continental and Cenex who operate refineries in Montana, and Husky who operates a refinery in Wyoming. The viewpoint of our group represents the outlook of the Northern Tier refineries who serve the Upper Midwest area.

Before discussing the Kitimat Pipe Line, I would briefly like to comment on the Northern Tier crude oil supply problem. As you know, most of the refineries along the Northern Tier have been historically dependent upon Canadian crude oil. Table I attached gives a list of the refineries that have been historically served by Canadian crude oil. Because of the rapid decline in reserves and a recent lack of success in exploration, Canada is phasing out exports to the United States. Priority I Northern Tier refiners will only have 252,000 B/D available from Canada in 1977, 160,000 B/D in 1978, and 98,000 B/D in 1979. Major investment in a pipeline system is required if these refineries are to continue to operate.

In evaluating the various alternative supply routes to the Northern Tier refineries, our group's main objective is to provide petroleum products to the consumers of the Twin Cities and surrounding areas at a competitive price. To achieve this goal we must select the transportation route that will provide the lowest laid-down cost of crude oil to our refineries. Our economic evaluations indicate that the Kitimat Pipe Line represents the lowest cost alternative and we believe that the recently issued Bonner & Moore study prepared under the direction of the Federal Energy Administration supports that conclusion.

Time is running out on us. Shortages of petroleum products may occur in the Twin Cities area in the years 1978 and 1979 unless some method of relief can be developed. Beginning in 1978, Canada's planned level of exports provides less than 50 percent of the crude oil needed for Northern Tier refineries. Construction of any new crude oil supply system cannot be completed before 1979 and there is insufficient capacity in product pipelines serving the area to make up the shortfall that will occur in refinery production. We are urgently asking officials of the Canadian and U.S. Governments to give their immediate attention to this problem. We hope that Canada can be persuaded to protect the Northern Tier refineries supply position during the pipeline construction period through either direct sale of crude oil or some method of exchange. While some token exchanges have been consummated under which U.S. refiners supply domestic U.S. crude oil into the Interprovincial system at Chicago in exchange for Canadian crude oil, the volume of these to date is not significant. To date the Canadians have not been receptive to exchanges of foreign crude oil delivered to Canadian refineries in exchange for Canadian crude oil. We hope that the obvious advantages of the Kitimat Pipe Line to Canada will help convince Canadian officials to continue our vital crude oil supply during the construction period.

Mr. Chairman, I would appreciate your attention to the map attached to our statement which shows the proposed route of the Kitimat Pipe Line. Completion of this pipeline will provide Northern Tier refineries access to Alaskan crude oil, Persian Gulf crude oil, and other crude oils in volumes from an initial 400,000 B/D expandable to as much as 1,500,000 B/D, depending on the final pipeline size selected. The Kitimat Pipe Line connects with the Interprovincial Pipe Line which has 400,000 B/D of spare capacity between Edmonton and Chicago and can expand further at a cost lower than new pipeline construction. The Interprovincial Pipe Line can serve not only the Northern Tier refineries but it can also deliver crude oil to the major refining centers of Chicago and Toledo and to refineries as far east as Buffalo. Construction of the Kitimat Pipe Line is the fastest, cheapest way to provide the Northern Tier refineries with access to crude oil and simultaneously provide access for large volumes of Alaskan crude oil to the main area of the U.S. market.

After completion of one hundred miles of new pipeline, the Rangeland Glacier system will have adequate capacity to serve the Montana refineries.

Kitimat Pipe Line expects to file a permit with the National Energy Board in the fourth quarter of 1976 and with timely approval we hope to start up the pipeline in 1979.

We believe the Kitimat Pipe Line represents the best solution to the Northern Tier crude oil supply problem for the following reasons:

1. Ready access to U.S. crude oil from Alaska.
2. An excellent deepwater port that can receive foreign or Alaskan crude oil in very large crude carriers.
3. Use of 300,000 to 400,000 barrels per day of spare capacity existing in Interprovincial Pipe Line, thereby minimizing investment.
4. If necessary, the Kitimat and Interprovincial systems can be economically expanded to move Alaskan crude oil to Chicago and other Midwest refining centers.
5. The Kitimat Pipe Line has many benefits to Canada which should be helpful in maintaining some crude oil supply from Canada during the construction period.
6. Kitimat's timing is compatible with the announced Canadian phase-out.
7. The Kitimat Pipe Line appears environmentally acceptable. Only four hundred miles of new pipeline right-of-way is required, and the Kitimat Harbor is already an industrial location.

The Kitimat group plans to approach the Canadian government and ask that they assist in developing a means of supplying the Northern Tier refineries with what might be termed "window crude" during the pipeline construction period. This could involve dedication of an additional 180 to 280 million barrels of Canadian reserves to the export market.

We have been reviewing three possible alternatives to the Kitimat Pipe Line. These are a new pipeline from Cushing, Oklahoma, to St. Paul, Minnesota; the Northern Tier Pipe Line project; and a possible pipeline from the Illinois area that would connect to the Capline system. The Sohio project to move Alaskan crude through Long Beach Harbor does not really assist Northern Tier refineries since it is still necessary to move the crude oil from West Texas to the Northern Tier area. The line from Cushing to St. Paul has some attraction but if this system were built the Minnesota/Wisconsin refineries would probably utilize 100 percent foreign crude oil to replace Canadian crude oil rather than Alaskan crude oil. In addition, the new line from Cushing to St. Paul would not alleviate the problem of the Montana refiners and it appears more expensive than Kitimat when tanker economics are considered.

A connection with the Capline system might be viable but would require a large expansion of Capline which might not be acceptable to all owners. If Capline could be expanded a new pipeline to the St. Paul area connecting with Capline appears economically attractive, especially when compared to a new pipeline from Cushing, Oklahoma to St. Paul.

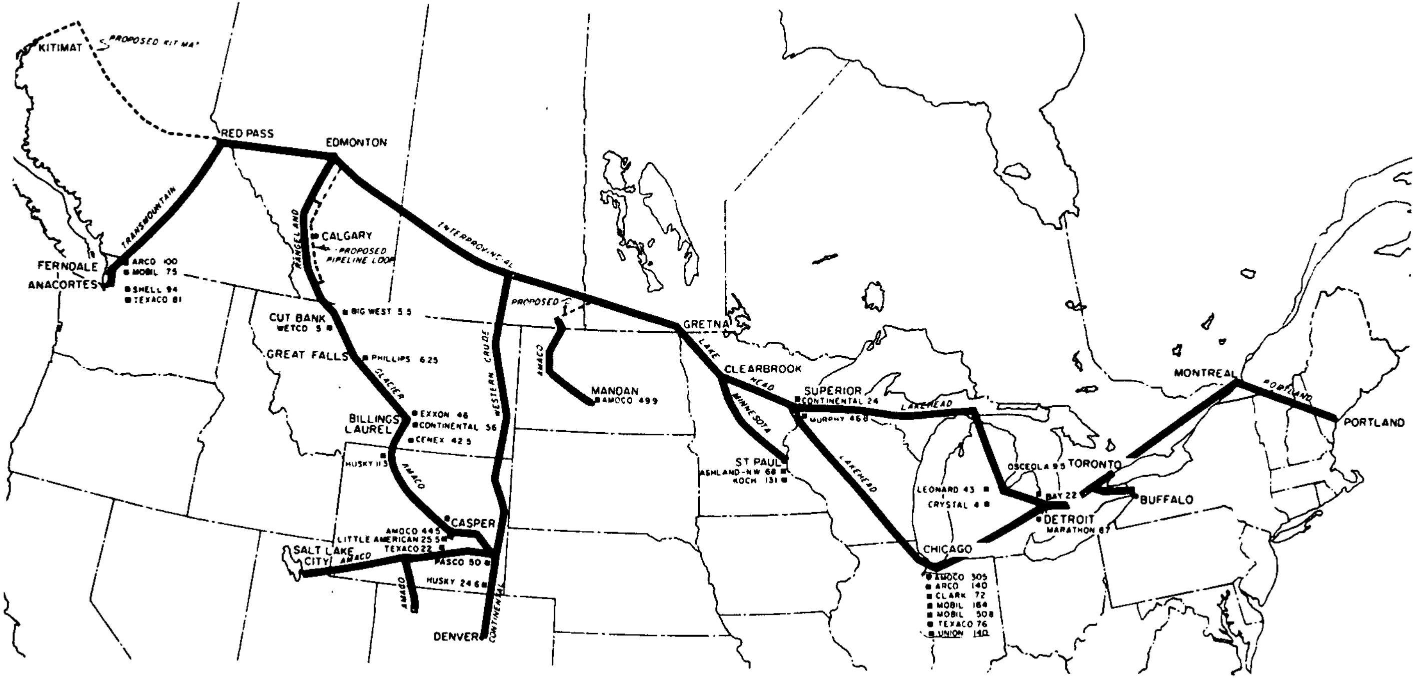
The economics of the Northern Tier system rely upon throughputs in excess of one million barrels per day. We find it difficult to envision that such throughputs can be achieved in the early years of pipeline operation. As you know, pipeline tariffs are a function of throughput. In order to gain a desired return on investment, as the throughput goes down the tariff must go up. We are concerned that the tariff required to service the debt associated with the Northern Tier project will put crude oil into the Twin Cities area at a noncompetitive cost that will place an economic burden not only on our company but on the consumers we serve. In addition, we are concerned about the time required to construct the Northern Tier line which is over 1,500 miles long, and we are further concerned that environmental considerations in the Puget Sound area will delay the project.

Apparently Williams Pipe Line Company plans to construct a new pipeline from Mason City, Iowa to St. Paul. When completed, this will permit Williams to transport approximately 80,000 B/D of crude oil to St. Paul from Oklahoma. While this additional quantity would be helpful during the difficult years of 1978 and 1979, this project does not represent a long term solution to the supply problems of the Northern Tier. If the Northern Tier refiners are to have a secure low cost source crude oil, a new pipeline system must be constructed similar to one of the alternatives previously discussed.

In summary, Mr. Chairman, the Kitimat Pipe Line gives Northern Tier refiners who serve the Minnesota/Wisconsin markets economic access to large volume shipments of crude oil from Alaska or the Persian Gulf. It is the fastest, cheapest, and best way to solve the supply problems of the Northern Tier refineries and assure an economic energy base for further growth of this important area of our country.

TABLE I.—*Northern Tier Refineries that will benefit from the Kitimat Pipe Line*

| *Company and location* | *Capacity, B/SD* |
|---|---|
| FEA Priority 1 refineries: | |
| Big West Oil Co., Kevin, Mont | 5,500 |
| Cenex, Laurel, Mont | 42,500 |
| Continental Oil Co., Billings, Mont | 56,000 |
| Exxon, Billings, Mont | 46,000 |
| Continental Oil Co., Wrenshall, Mont | 24,000 |
| Koch Refining Co., Pine Bend, Minn | 131,905 |
| Ashland Oil—NW Ref., St. Paul Park, Minn | 68,000 |
| Murphy Oil Corp., Superior, Wis | 46,800 |
| Total | 420,705 |
| FEA priority 2 refineries: | |
| Atlantic Richfield, Ferndale, Wash | 100,000 |
| Mobil Oil, Ferndale, Wash | 75,000 |
| Shell Oil, Anacortes, Wash | 94,000 |
| Texaco, Anacortes, Wash | 81,000 |
| Phillips Petroleum, Great Falls, Mont | 6,250 |
| Westco Ref. Co., Cut Bank, Mont | 5,000 |
| American Oil Co., Mandan, N. Dak | 49,900 |
| American Oil Co., Casper Wyo | 44,500 |
| Husky Oil Co., Cheyenne, Wyo | 24,600 |
| Husky Oil Co., Cody, Wyo | 11,300 |
| Little American Ref. Co., Casper, Wyo | 25,500 |
| Pasco, Inc., Sinclair, Wyo | 50,000 |
| Texaco, Inc., Casper, Wyo | 22,000 |
| Total | 589,050 |


KITIMAT
PROPOSED KITIMAT
RED PASS
EDMONTON
TRANSMOUNTAIN
RANGELAND
CALGARY
PROPOSED PIPELINE LOOP
INTERPROVINCIAL
FERNDALE
ANACORTES
ARCO 100
MOBIL 75
SHELL 94
TEXACO 81
CUT BANK
WETCO 5
BIG WEST 5.5
GREAT FALLS
PHILLIPS 6.25
GLACIER
BILLINGS
LAUREL
EXXON 46
CONTINENTAL 56
CENEX 42.5
HUSKY 11.3
AMACO
CASPER
AMOCO 44.5
LITTLE AMERICAN 25.5
TEXACO 22
PASCO 50
HUSKY 24.6
SALT LAKE CITY
DENVER
WESTERN CRUDE
CONTINENTAL
PROPOSED
MANDAN
AMOCO 49.9
GRETNA
LAKEHEAD
CLEARBROOK
MINNESOTA
ST PAUL
ASHLAND-NW 68
KOCH 131
SUPERIOR
CONTINENTAL 24
MURPHY 46.8
CHICAGO
AMOCO 305
ARCO 140
CLARK 72
MOBIL 164
MOBIL 50.8
TEXACO 76
UNION 140
LEONARD 43
CRYSTAL 4
OSCEOLA 9.5
BAY 22
DETROIT
MARATHON 67
TORONTO
BUFFALO
MONTREAL
PORTLAND

Chairman HUMPHREY. Depending on what the time constraints are, we may very well want to follow up this hearing because we haven't heard as much as we should from the northern tier and Kitimat proponents. We might want to have a short hearing on this and I will be in touch with you later.

Mr. Thiss.

## STATEMENT OF GEORGE THISS, EXECUTIVE DIRECTOR, THE UPPER MIDWEST COUNCIL, MINNEAPOLIS, MINN., ACCOMPANIED BY MIKE MURPHY

Mr. THISS. Mr. Chairman, Mike Murphy has joined me. Mike is in charge of the management of the council's energy work.

Chairman HUMPHREY. You are testifying here as the executive director of the Upper Midwest Council.

Mr. THISS. We appreciate the opportunity to testify and we recognize pressing deadlines you are under.

At your request, the focus of our testimony is on the natural gas supply. Our full testimony touches on several other points.

Let me first take up the natural gas question in abbreviated testimony. We believe the Arctic Gas proposal for a pipeline through Canada to the Midwest and West is in the best interest of the Nation as a whole. We also believe that it best serves the interest of the Upper Midwest. Clearly, our objectives in selecting a natural gas transportation route must be based on developing a system which provides the most economical, efficient, environmentally sound and firm, long-term benefits. We believe the Arctic Gas proposal meets those criteria for the following reasons:

(1) Arctic Gas offers substantially lower consumer costs overtime, creating an annual savings to consumers in excess of $700 million per year.

(2) Arctic Gas will provide access to greater volumes of proven and potential supplies and will give this region a direct link with the Arctic fields. Otherwise, we would be forced to rely upon supply displacement mechanisms in the 48 States—mechanisms which raise several uncertainties.

(3) The Arctic Gas venture provides the United States and Canada an opportunity for a new kind of joint energy venture which is in the best interests of both nations. The treaty dealing with the movement of hydrocarbons, recently initialed by both sides, will help to reduce uncertainties which have risen because of recent Canadian oil and natural gas export and price policies. Our record of amiable energy relationships with Canada has been good and represents a strong base upon which to build.

(4) Arctic Gas is the most energy efficient of the three alternatives being considered and also increases flexibility of our pipeline network in this region. The Arctic Gas line will pass through potential natural gas areas in Canada and should be an incentive to spur exploration in those areas. The Arctic Gas line will be more easily expanded to handle higher volumes which may be produced in the North.

There are potential problems. Environmental issues loom large in Alaska and in Canada. Arctic Gas, however, has spent far more money and devoted much more effort to the study of these problems than have the two competing proposals.

In our testimony we touch on several other issues in addition to the natural gas pipeline. One is the Canadian crude oil question which has been talked about this morning. The point we raise here, I guess, is that there are common problems resulting from Canadian oil export policies, but maybe there are not common solutions. One solution might be better for Minnesota, another better for North Dakota. Maybe Montana has difficulties with the potential suggestion.

Other areas that we want to stress and include in the testimony are timing, which has been alluded to many times this morning. You have shown well in your questioning that both in natural gas and the crude oil question of timing is critical.

We touch on shortages and costs. What happens under some of the shortages, whether it be from cold weather or from embargo, heaven forbid; what do we do? How do we relate, country to State, under some of these conditions? How do we stay flexible?

Finally, costs, which haven't been touched on much this morning, but which are important. This particular region, as we have seen in some publicity lately, sometimes is on the short end on decisions made in Washington. Maybe the cost factor in energy here may provoke those further. We hope not, but we think it is important to enter those kinds of things in the discussion.

Mr. Chairman, that's in a brief way our testimony. Thank you.

[The prepared statement, with an attachment, of Mr. Thiss follows:]

PREPARED STATEMENT OF GEORGE THISS

ENERGY IN THE UPPER MIDWEST

Mr. Chairman, Mr. Zarb, and ladies and gentlemen. I appreciate the opportunity to testify on the energy situation and problems of the Northern Tier States and, particularly, Minnesota.

The Upper Midwest Council is a regional organization devoted to the study of issues and opportunities which face the Upper Midwest. In this role, we have analyzed and reported on oil, natural gas, coal, electric power and energy conservation issues for the past three years. Our study region fits nearly precisely with the so-called "Northern Tier" and for that reason, we have a keen interest in the export policies of Canada relating to oil and natural gas. We also have looked closely at alternatives for moving Arctic natural gas to the 48 states and at alternatives for supplying crude oil to this region. My testiminy today will address each of these particular subjects as well as their interrelationships and implications.

*Crude oil and petroleum products*

There are three significant proposals—Kitimat, Northern Tier and Williams Bros.—which stand to improve the region's crude oil and product position in the future. Only one plan—Williams Bros.—will provide help in the near term and even that proposal will not meet the full needs of this region as Canadian crude oil supplies decline.

Beginning early in 1977, this region will begin to feel the effects of Canadian curtailments. These effects will manifest themselves in higher prices for crude oil due primarily to higher transportation costs. Expansion of the Williams Bros. system will help to alleviate these pressures later in 1977. Williams Bros. has discussed further expansion of its system; yet no firm actions have been taken. Even those future expansions do not alleviate our problems, however. By late 1977, the crude oil deficit for this region could well be 80 to 120 thousand barrels per day.

Under ideal conditions, the Kitimat line will not be operational prior to early 1979 and the Northern Tier proposal could not come on line any sooner.

Thus, the near-term crude oil and product picture for this area is, at best, one of higher prices for supplies we receive. The worse case will be actual shortages because existing distribution systems probably will not have adequate capacity to counterbalance declining Canadian crude oil supplies. Therefore, the dilemma we face is one of timing. No matter what, we face problems. Efforts which may reduce lead times for placing new systems into operation will be critical for this region. We truly have but one alternative—intense conservation—an alternative which does not promise much given current public attitudes and policy uncertainties at both federal and state levels.

As a regional organization we study the geographical area from Montana east to the Upper Michigan Peninsula. While this region has common problems resulting from changing Canadian oil export policies, a common solution may not be available.

The Kitimat plan does well to meet future needs of refiners in Minnesota, Wisconsin and Michigan. We are concerned, however, whether the Kitimat proposal will provide adequate relief to the Dakotas and to Montana. Incidentally, a large portion of the petroleum product supplies marketed in parts of Idaho, and in eastern Washington and Oregon come from refinery operations in Billings, Montana, complexes now served by Canadian sources. We see in this instance that alternatives for some areas may cause conflicts or other problems for other areas. Added attention should be given to this potential problem.

Estimates received from Williams Bros. indicate that this region, even with normal seasonal temperatures could experience an 80–90 thousand barrel per day shortage of crude oil during the 1976–77 winter. Swap agreements with Canada could help to alleviate some of this problem. Indeed, a few swaps of small volume have been agreed upon. Our information indicates, however, that the Department of Commerce has been slow to encourage such swaps and has held up approvals on some proposals.

*Natural gas supplies*

Obviously, our oil problems are aggravated by curtailments and/or higher prices in the natural gas sector. While our natural gas curtailments are expected to be minimal (in contrast to other regions), we, too, will feel the effects of higher domestic gas prices. Some parts of the region already are being impacted heavily by fast-rising Canadian natural gas prices.

Again, timing for alternatives is critical. There are no major proposals to consider which will provide added natural gas supplies between now and 1981. at the earliest. It is not until 1981 that one optimistically could anticipate the 48 states receiving natural gas from the Arctic region.

In testimony we submitted to two Subcommittees of the U.S. House of Representatives in early August of this year, the Council recommended that the Arctic Gas proposal be chosen as the best means for moving natural gas from the Arctic to the 48 states. I will summarize that testimony here. The full text of our report is included as part of this prepared statement here today.

We believe the Arctic Gas proposal for a pipeline through Canada to the Midwest and West is in the best interest of the nation as a whole. We also believe it best serves the interests of the Upper Midwest. Clearly, our objectives in selecting a natural gas transportation route must be based on developing a system which provides the most economical, efficient, environmentally sound and firm, long-term benefits. We believe the Arctic Gas proposal meets those criteria, and for the following reasons:

1. Arctic Gas offers substantially lower consumer costs over time creating an annual savings to consumers in excess of $700 million per year.

2. Arctic Gas will provide access to greater volumes of proven and potential supplies and will give this region a direct link with the Arctic fields. Otherwise, we would be forced to rely upon supply displacement mechanisms in the 48 states—mechanisms which raise several uncertainties.

3. The Arctic Gas venture provides the U.S. and Canada an opportunity for a new kind of joint energy venture which is in the best interests of both nations. The treaty dealing with the movement of hydrocarbons, recently initialed by both sides, will help to reduce uncertainties which have risen because of recent Canadian oil and natural gas export and price policies. Our record of amiable energy relationships with Canada has been good and represents a strong base upon which to build.

4. Arctic Gas is the most energy efficient of the three alternatives being considered and also increases flexibility of our pipeline network in this region. The

Arctic Gas line will pass through potential natural gas areas in Canada and should be an incentive to spur exploration in those areas. The Arctic Gas line will be more easily expanded to handle higher volumes which may be produced in the North.

There are potential problems. Environmental issues loom large in Alaska and in Canada. Arctic Gas, however, has spent far more money and devoted much more effort to the study of these problems than have the other two competing proposals.

Timing is critical. Each passing day raises the cost of any one of the three proposals by about $1 million. Arctic Gas proponents and member firms have developed extensive information and organizational capacity to implement financing for their proposal and already have the initial infrastructure in place to begin construction. The other two proposals lag behind in these areas. Because timing is critical, we wholeheartedly support the procedural legislation for making decisions on this issue which was passed by the Senate and is now being considered by the House.

*Timing*

As I have repeatedly stressed throughout this testimony, timing is critical. The major proposals for injecting new energy supplies into this region do not alleviate our growing short- and near-term problems. Deregulation of oil and natural gas prices will not help this area for several years due to the lead times required to bring new supplies from well to consumer. Pipeline proposals now being considered and designed have lead times, which, under even most optimistic conditions, will not increase our supplies at a rate and during the same time period to match declining supplies of Canadian crude oil and curtailment of domestic natural gas service.

During this critical period through the end of this decade, we must concentrate heavily on increasing flexibility at both the supply and use level. We must continually assess and reassess our supply and distribution network to take advantage of every opportunity. We must continually survey the use sector to anticipate problem areas and to take advantage of opportunities to adjust use patterns. These kinds of efforts require a great deal of study in advance of the occurrence of problems. Cooperative federal and state efforts will be critical, particularly in identifying what, if any, alternatives may be impeded by conflicts between federal and state policies and federal and state goals and objectives.

*Shortages*

In order to overcome spot shortage situations as well as prolonged and more serious shortage and higher price problems due to unavailability of crude oil from traditional sources, this region will need to make use of all available supply networks, including: barges, oil unit trains, spot capacity on pipelines and swap arrangements of any volume. Further flexibility must be built into our efforts through the development of contingency and emergency plans designed to meet state needs. Obviously, state plans must be compatible with federal and regional policies. However, states are in a much better position to assess local needs and to respond quickly to problem conditions. Federal efforts should be highly supportive of state and local initiative in order to reduce margins of error and to increase response time.

When our natural gas curtailments become significant, we must insure that federal, state, pipeline company and distribution company curtailment programs are compatible. Fuel allocations for agriculture, for instance, will do little for us if we've no allocation for critical agri-business operations such as the dried milk industry.

While like the rest of the nation, we are vulnerable to another embargo, we also face serious problems if the coming winters bring us a prolonged cold spell. As you well know, every state is charged with development of emergency allocation and contingency plans for meeting such adverse conditions. Some areas of the nation might find themselves having to take actions which could conflict with existing federal curtailment and allocation policies. Again, flexibility to take separate actions at local levels will be imperative.

*Costs*

As you can see, our problems are serious for the next three to seven years. We can fully expect higher prices for both crude oil and products—prices which may cause us some regional disadvantages. Higher natural gas prices nationwide, coupled with rising natural gas curtailments, likely will culminate in physical shortages for some periods in this area and, certainly, will cause operational difficulties for some use categories.

This region must be and is concerned about regional dislocations which could cause existing industries to reduce operations or move out. Also, existing industries may decide not to expand in this region and some new industries would look elsewhere. Already, some of these things have happened to this area and other northern regions; and we've yet to enter into a period of prolonged energy shortage and price problems.

Offsetting these higher costs will require innovative programs to provide tax programs and subsidy programs which will give users incentives to switch to alternative fuels, improve efficiencies and to introduce new technologies and the point of end use. A federal position supportive of state actions through financial assistance and through uniformity to reduce the potential for regional disadvantages occurring would be highly desirable.

Federal and state efforts should be highly supportive of private sector—energy and otherwise—actions to spur investigation of and investment in alternative energy sources and use systems. In particular, greater attention must be given to small and medium-sized businesses which need outside support because they currently lack the expertise, money, and time to undertake the studies required or to finance the changes they could make to improve their energy use patterns.

I thank you for this opportunity to appear here today. I will be pleased to answer any questions you might have.

Attachment.

# TRANSPORTING ARCTIC-REGION NATURAL GAS TO THE 48 STATES

Presented as Testimony to

Subcommittee on Public Lands
INTERIOR AND INSULAR AFFAIRS COMMITTEE
and
Subcommittee on Energy and Power
INTERSTATE AND FOREIGN COMMERCE COMMITTEE
of the
U. S. HOUSE OF REPRESENTATIVES

by the

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August 5, 1976

**The UPPER MIDWEST COUNCIL is a non-profit, non-partisan corporation . . . promoting better understanding of regional choices for the future.**

# TRANSPORTING ARCTIC-REGION NATURAL GAS TO THE 48 STATES

For more than two years, the Federal Power Commission, Congress and the Administration have studied and debated alternative proposals for moving natural gas from the Arctic region to the contiguous 48 states. Two primary proposals - El Paso, across Alaska and via tankers to southern California; Arctic Gas, across Alaska, through western Canada and into the U.S. - have been most thoroughly considered. A third proposal - Alcan, across Alaska and through Canada carrying only U.S. gas - was announced in May.

At this time, the House of Representatives is considering a Senate-passed bill (S.B. 3521) which would speed up the decision-making process and help to avoid protracted political battles and attendant delays in designating the preferable route for moving natural gas south from the Arctic. The bill would require a Federal Power Commission recommendation on the most preferable system by March 1, 1977; a presidential decision by July 1, 1977; and concurrence from Congress by September 1, 1977.

Coincidentally, Canadian interests are examining alternatives in terms of their own interests. Also, negotiations are proceeding between the U.S. and Canada and a treaty has been initialed by both sides. It would allow for nondiscriminatory treatment of hydrocarbons owned by one nation and flowing in pipelines of the other; and would assure the flow of energy in such a way that neither country could arbitrarily cut off deliveries of hydrocarbons to the other country. All three processes must evolve with some sense of coordination so that a decision by one nation does not inadvertantly cause difficulties for the other.

COUNCIL OBJECTIVE: The purpose in studying this topic is to consider the net effect of any of the three alternative transportation systems on the Upper Midwest and the nation as a whole. The effort is designed to summarize for purposes of comparison the key factors of economics, timing, physical capabilities and impacts, domestic and international political factors and net energy contributions of the proposed systems in terms of how they fit into the region's energy picture and that of the nation.

## RECOMMENDATION

The Arctic Gas proposal is recommended as the system which provides the best overall benefits to the Upper Midwest and the nation as a whole. In this situation, the interests of the region and the nation are not substantively different. Clearly, the objective for the nation, for all regions and for all persons is to pursue the system which provides the most economical, efficient, environmentally sound and firm, long-term supply alternative.

MAJOR REASONS: The Arctic Gas proposal best serves the interests of the American people because:

- It offers substantially lower costs to consumers in both the short- and long-term -- more than $700 million per year.
- Access to total proven and potential Arctic gas reserves is greater through a joint system with Canada.
- It provides Canada an economical means for moving its gas reserves to Canadian markets.
- It provides both nations an opportunity to work together aggressively to the mutual benefit of both.
- Gas Arctic has done substantially more study and has created a more sophisticated organization through which to implement the planning, construction and operation efforts required to bring the energy supplies to market. This will help reduce further delays in providing access to supplies.

Also, the Arctic Gas system, by its very location through Canada, would act as a major stimulus to additional exploration in the MacKenzie Delta region. Further, its presence in Canada would also stimulate energy exploration along most of its route because the line would traverse a very large area of sedimentary deposits necessary for oil and gas accumulation. Neither the El Paso nor Alcan lines, except for those segments already served by pipelines, traverses any areas where sedimentary deposits are located. The stimulation of exploration and possibility of finding of significant Canadian oil and gas reserves would help to improve the North American energy picture. The United States would, therefore, benefit.

Lastly, the Gas Arctic proposal would mean that additional transportation facilities would be introduced into the central regions of the North American Continent in both Canada and the U.S.; increasing future flexibility for both nations in the movement of natural gas to consumers.

## SUMMARY ANALYSIS

### Situation

Substantial volumes of natural gas have been found in the Prudhoe Bay region of Alaska and the MacKenzie Delta region of northwest Canada. In addition, potential reserves in these two regions are considered immense and are growing as exploration widens. Development of a system for moving gas from these areas is critical to the energy future of the two nations in the coming years.during which supplies from traditional on-land and off-shore production areas is declining. Arctic natural gas supplies are not a panacea; they are but one piece of what many consider a comprehensive program to secure additional natural gas supplies from a wide variety of sources.

Efforts to date in Congress and by the Federal Power Commission to choose between the two most widely known proposals - Arctic Gas (a consortium involving several U.S. and Canadian natural gas and other energy companies) and El Paso (a proposal of the El Paso Natural Gas Company) - have been stymied by the realization that, no matter which system chosen, considerable litigation likely will follow, further delaying ultimate implementation of any plan. The Alcan (Northwest Pipeline Corporation) proposal, announced in mid-May, 1976, could serve to delay a final decision because only preliminary study has been done on this alternative. At this time, relatively little detailed data is available with which to make reasonable comparisons with the other two proposed systems. Additionally, there are all-Canadian proposals which would move only Canadian gas to Canadian markets.

Currently, legislation is being considered in Congress to produce a procedural pipeline bill (S.B. 3521). This legislative alternative to mandating a particular route has evolved due to concern that regional competition for the delivery system would block any legislation via filabuster action.

## SYSTEM DESCRIPTION/COMPARISONS

### ROUTES OF SYSTEMS (see maps attached at end)

El Paso would build a 42-inch, 809-mile long pipeline paralleling the oil line route of Alaska Pipeline Company. At Point Gravina, Alaska, the gas would be liquified and moved via tanker fleet to a point near Los Angeles. A 142-mile long, 42-inch line would be built near Los Angeles to interconnect with existing gas networks for distribution of the Alaskan gas. Also, pipeline capacity would have to be built to serve the northwest U.S. In reality, much of the Alaskan gas would stay on the West coast; but its presence there may allow supplies now being sent west from the Texas/Oklahoma region to be diverted to other gas consuming areas of the U.S. In this manner of displacement, the Upper Midwest could receive the benefits of Alaskan natural gas development on the basis of how much reserves in Alaska are owned by regional suppliers. Some questions have been raised, however, regarding whether displacement of gas supplies will occur or can occur. In terms of the future, midwestern and eastern users would have to rely on currently shrinking traditional fields while western users could have access to new and expandable Arctic reserves.

The Arctic Gas would involve 4,490 miles of line, including 195 miles of 48-inch line from Prudhoe Bay, Alaska to near the MacKenzie Delta in Alaska. From there, the 48-inch line would move south a total of about 2,150 miles to a point near Caroline, Alberta. From this point north of Calgary, Alberta, the gas would move into the U.S. via two legs - one into the western states and one, a new 42-inch line, through the Midwest to Chicago. The western lines will take advantage of existing and already proposed pipelines.

Alcan proposes to construct 5,000 miles of line, including a 42-inch line along the so-called "Fairbanks Route" in which the Alaska leg of the system would parallel the oil line to Fairbanks and then move easterly into Canada to connect with existing gas lines in both British Columbia and Alberta. The Alaskan portion of the line would run 730 miles; the Canadian leg 936 miles. Additional pipe would be required in the U.S., too.

CAPITAL COSTS

El Paso's proposal would cost about $7.90 billion assuming a system capable of moving 2.4 billion cubic feet per day (Bcf/day). El Paso recently proposed to build a 3.4 Bcf system but has announced no specific dollar amount for that system. Absent in this cost figure are the expenditures which will be required to construct additional pipeline facilities within the 48 states to insure that displacement of gas supplies will occur. There is concern whether companies in the Midwest and East which own or will own Arctic gas reserves can obtain the supplies they need.

Arctic Gas's plan would cost a total of $8.30 billion. However, $1.50 billion of this cost is applicable to the movement of Canadian gas in the system. Therefore, the net capital cost to the U.S. applicable to U.S. consumers would be about $6.80 billion. This last figure includes $1.4 billion reserved for funds used during construction. Arctic Gas figures are the result of more in-depth study than are the figures of the other two proposals, and have been subjected to greater review. The Arctic Gas consortium of companies has, to date, been much more aggressive in developing the managerial infrastructure and financial planning links which are capable of producing more detailed and usable numbers for analysis.

Alcan's proposal is estimated at about $4.6 billion total. Of that figure, about $2.3 billion to build the line in Alaska would be applied against U.S. interests, while the remaining $2.3 billion would be spent by Canadian partners in the venture to construct the Canadian portion of the line. Alcan has indicated that the involved Canadian interests have agreed to spend this amount themselves. The Alcan proposal also does not include the additional pipeline facilities which will be required to move natural gas into the Midwest and East.

ACCESS TO PROVEN RESERVES

El Paso would create access to about 24 trillion cubic feet (Tcf) of proven reserves in Alaska.

Arctic Gas would create access to 24 Tcf in Alaska plus another 7 Tcf in Canada. (Canadian gas would move with Alaskan gas. However, Canadian gas would supply Canadian not U.S. markets.)

Alcan would create access to about 24 Tcf of Alaskan gas reserves and not provide access to Canadian reserves even though the line would traverse Canada.

NOTE: Potential reserves in Alaskan fields have been estimated as high as 100 Tcf. Potential reserves in the MacKenzie Delta area have been estimated as high as 74 Tcf.

PIPELINE VOLUMES

El Paso proposes a system which would carry 3.2 Bcf/day of Alaskan gas.

Arctic Gas would build a system which would carry 4.5 Bcf/day maximum. It is expected that initially 2.00 Bcf/day would be available from Alaska and 1.00 Bcf/day from the MacKenzie Delta. By the fifth year, maximum volumes would be moved with 2.25 Bcf/day going to the U.S. and a like amount to Canadian users.

Alcan proposes a line to carry 2.4 Bcf with initial deliveries commencing at 1.00 Bcf. All of this would be Alaskan gas.

NOTE: Generally it is believed that efforts in the future to expand carrying capacities of these three systems are less costly on the pipelines through looping lines and increasing pumping pressure. The El Paso system would require increased capacities at the liquifier and gasifier plants as well as additional tankers. Arctic Gas has planned for future expansion by building its Alaskan segment at 48-inch diameter which will allow for increased movements of gas in the future without having to build new pipelines. Incremental line capacity expansion would be readily possible.

TIME REQUIREMENTS FOR CONSTRUCTION

El Paso initially proposed low-volume deliveries within just under 6 years from start of construction. Later filings indicated full scale deliveries could occur within 6 years.

Arctic Gas indicates that MacKenzie Delta gas could be in Canadian markets within 3.5 years and that Alaskan gas could be in U.S. markets a year later or over a total of 4.5 years construction.

Alcan's announcement indicated it could have Alaskan supplies to U.S. markets within 3 years or from 2 to 3 years sooner than could the other systems. However, Alcan has made only basic application and has just begun studies.

NOTE: Of the three proposed systems, only Arctic Gas has gone through the complexities of developing a supportive organization which aids in construction and financing of the system. Neither El Paso nor Alcan has produced environmental materials supporting their applications. Arctic Gas has developed the consortium of firms, a working financial plan, equity commitments and supportive organizational systems needed to proceed once a decision is reached in Washington, D.C.

## MAJOR ISSUE AREAS

ENVIRONMENT

The El Paso line would follow the Alaska Oil Pipeline route, making use of existing haul roads, buildings, equipment, etc. Concerns have been raised over liquified gas tankers and potential explosions. El Paso will affect only about one-fifth the land surface the other two systems will.

Arctic Gas's line as proposed would traverse the northern side of the Alaskan Wildlife Range, a subject of much concern to environmentalists. Arctic Gas points out, however, that legislation creating the Range made provisions for use of certain areas for pipelines. Arctic Gas indicates that the northerly route along the coastal areas is more preferable overall than an alternative proposal to construct the Alaskan segment of its system along the southern edge of the Alaskan Wildlife Range. In addition, there are environmental concerns over building the line through currently untouched natural areas in Canada. The Federal Power Commission's final Environmental Impact Statement found the Arctic Gas plan superior to that of El Paso.

The Alcan proposal would only partly follow existing oil line and highway corridors in Alaska and Canada respectively, thus creating several environmental impacts. Alcan's pipeline requirements will exceed those of Arctic Gas, disrupting more land area.

ENERGY LOSSES

El Paso's system would lose about 13.0 percent of the total natural gas introduced at Prudhoe Bay due to the energy requirements for liquification, tanker shipment, gasification and miscellaneous operations.

Arctic Gas's system would consume about 9.60 percent total energy carried.

Alcan's proposal would, it is believed, be less efficient than the Arctic Gas proposal in terms of energy consumption per unit of natural gas shipped.

CONSUMER COSTS

The Arctic Gas alternative will be LESS COSTLY to the consumer. Current estimates indicate the Arctic Gas system will save consumers over $700 million annually in comparison to the El Paso system. To date, Alcan has not produced specific data on consumer costs.

The table which follows provides comparative figures for transportation costs for moving Alaskan natural gas to three locations in the 48 states. These figures are based upon a 20-year averaging of costs. For each system, daily average flows were placed at 2.5 Bcf/day for comparative purposes. These figures are based upon the best available data or reliable estimates of costs. Figures shown for Alcan actually are drawn from a similar but not precisely the same route and system which Northwest Pipeline Corporation proposes.

Even when figuring these transportation costs on a 10-year average basis, the differences remain quite favorable to Arctic Gas. The savings obtainable to consumers via Arctic Gas would total $14 billion for moving the entire volume of Alaskan proven reserves (24 Tcf) over the lifetime of the system's operation.

TRANSPORTATION COSTS EXPRESSED IN DOLLARS
PER THOUSAND CUBIC FEET MOVED

| Delivered to: | via Arctic Gas | via El Paso | via Alcan |
|---|---|---|---|
| S. Calif. | $1.17 | $1.70 | $1.48 |
| Chicago | $1.18 | $2.00 | $1.58 |
| Pittsburgh | $1.27 | $2.17 | $1.68 |

NOTE: These figures were supplied by four firms expert in the planning, construction, financing and operation of pipeline and other energy moving systems. Those firms are: Purvin & Gertz, engineering consultants; J. J. McMullen & Associates, Inc., marine transportation experts; Northern Engineering Services, Ltd., experts in pipeline design/operation; and Morgan Stanley & Company, a financial institution.

INTERNATIONAL POLITICS

The El Paso system would traverse only U.S. lands, thus requiring no approvals or negotiations with other nations. Selecting the El Paso route might foreclose the Canadians having an economically viable option for moving gas south from the MacKenzie Delta, however; a situation which potentially could aggravate U.S./Canada relations.

Alcan will traverse both U.S. and Canadian lands, yet it will not move any Canadian natural gas. It would require approvals from Canada's government while not providing any direct benefits to Canada. Benefits occurring in Canada would involve Canadian investment and efforts to build and operate the line plus operating revenues to Canadian pipeline companies.

Arctic Gas will require a coordinated process of analysis and decision making, coupled with renegotiated trade agreements and treaties to allow the system to be implemented.

CANADIAN-AMERICAN RELATIONS

Since a treaty addressing the movement of hydrocarbons across borders and through pipelines owned by interests in the two countries has been initialed, a major step has been taken toward removing any concerns over whether Canada could, in fact, interrupt pipeline operation through its territory. Even without a treaty, the current movement of Canadian energy supplies through the United States should be sufficient to allay any fears of Canadian action.

About 40 percent of Canada's natural gas and nearly all of the oil produced in western Canada and used in eastern Canada passes through the United States. Oil Canada purchases from other nations passes through New England into the Montreal area. The long history of movement of U.S. goods through the St. Lawrence Seaway has provided no instances of discriminatory action, taxation or expropriation.



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## COSTS AND BENEFITS

El Paso would make use of all-American industries, people, etc. All taxes, wages, income, etc., would flow into the U.S. The El Paso proposal would not provide a means for Canada to move its natural gas south, however; potentially denying Canada of an economical option.

Arctic Gas would pay about 80 percent of total construction costs to U.S. interests with the other 20 percent going to Canadian interests. In addition, it is estimated that about $200 million in taxes per year will be paid to Canada. Arctic Gas would provide a means for moving Canadian gas to Canadian markets more economically than within other proposals made previously by Canadian pipeline interests.

Alcan would split the total project cost between U.S. interests and Canadian interests. U.S. consumers, however, will pay for the Canadian portion of the line in the end. Operating revenues also would be split because Canadian companies would own the Canadian segments of the system. Alcan also does not provide a means for moving Canadian gas to market, yet it requires approvals from the Canadian government to move natural gas from Alaska through Canada.

Dr. Ezra Solomon of Stanford University, in studying the balance of payments situation posed by Arctic Gas, determined that the Arctic Gas project would yield a net balance of payments benefit to the United States in the amount of $3-4 billion over the first ten years of operation.

The net benefit from Arctic Gas is in direct contrast with a zero balance of payments situation via the El Paso proposal. The Alcan proposal would provide no balance of payments advantage and American consumers would end up paying for the portion of the line in Canada even though it would be built and operated by Canadian interests. Canada would receive income from the Alcan line but would not bear the cost.

### UPPER MIDWEST CONCERNS

Minnesota, Wisconsin and parts of South Dakota and upper Michigan are served by members of the Arctic Gas consortium. Western South Dakota, Montana and North Dakota are not. Officials in both North Dakota and Montana have expressed concern that lines through their states may not provide them access to Arctic gas supplies. At this point, these states (and their private natural gas distributors) should investigate securing an option position in the Arctic. If this is not economically feasible, gas suppliers in these states should investigate opportunities for developing joint relationships with those other gas companies who now have or will be developing option positions for purchase of Arctic natural gas supplies.

## RECOMMENDATION

The Arctic Gas proposal represents the most desirable system in terms of both the regional interest and the national interest. The major reasons of this position are:

ECONOMICS: The Arctic Gas proposal offers substantially lower consumer costs over time due to significantly lower operating costs and more direct movement of energy to consumers.

ACCESS TO SUPPLIES: Arctic Gas offers access to proven U.S./Canada reserves totalling 31 Tcf. Potential reserves for both nations total 174 Tcf. El Paso or Alcan would provide access only to U.S. reserves totalling 24 Tcf. proven and 100 Tcf. potential. Arctic Gas would be a direct link between the Upper Midwest and Arctic reserves, not dependent upon gas displacement methods in the 48 states.

U.S./CANADA RELATIONS: The Arctic Gas system provides a new and opportune joint venture for both nations. It also can be implemented without falling into past patterns of U.S. actions over-influencing Canadian economics. The development of the energy treaty does much to enhance future Canadian-American activities. Potential Canadian energy reserves in the Arctic region west of Hudson Bay are immense and will require joint ventures to develop. Concerns over pipeline operation seem about to be resolved and history shows a solid, positive working relationship between the two nations in the area of commodities movement, thus allaying any suspicions.

DELIVERY TO THE 48 STATES: The Arctic Gas system provides the most desirable means for delivering maximum amounts of natural gas the most economical and direct way to more areas of the 48 states. The Arctic Gas system also provides the most readily expandable system for handling future, higher volumes should the potential reserves in the Arctic prove up as hoped.

SERVING THE NATIONAL INTEREST: Each of the three proposing private organizations seeks to gain approval for its system because of its own interests. Yet, there also is the issue of how best to serve the national interest. The Arctic Gas proposal represents the best opportunity available now and in the future to serve the national interest and to serve the interest of the firms which make up the Arctic Gas consortium and their direct consumers.

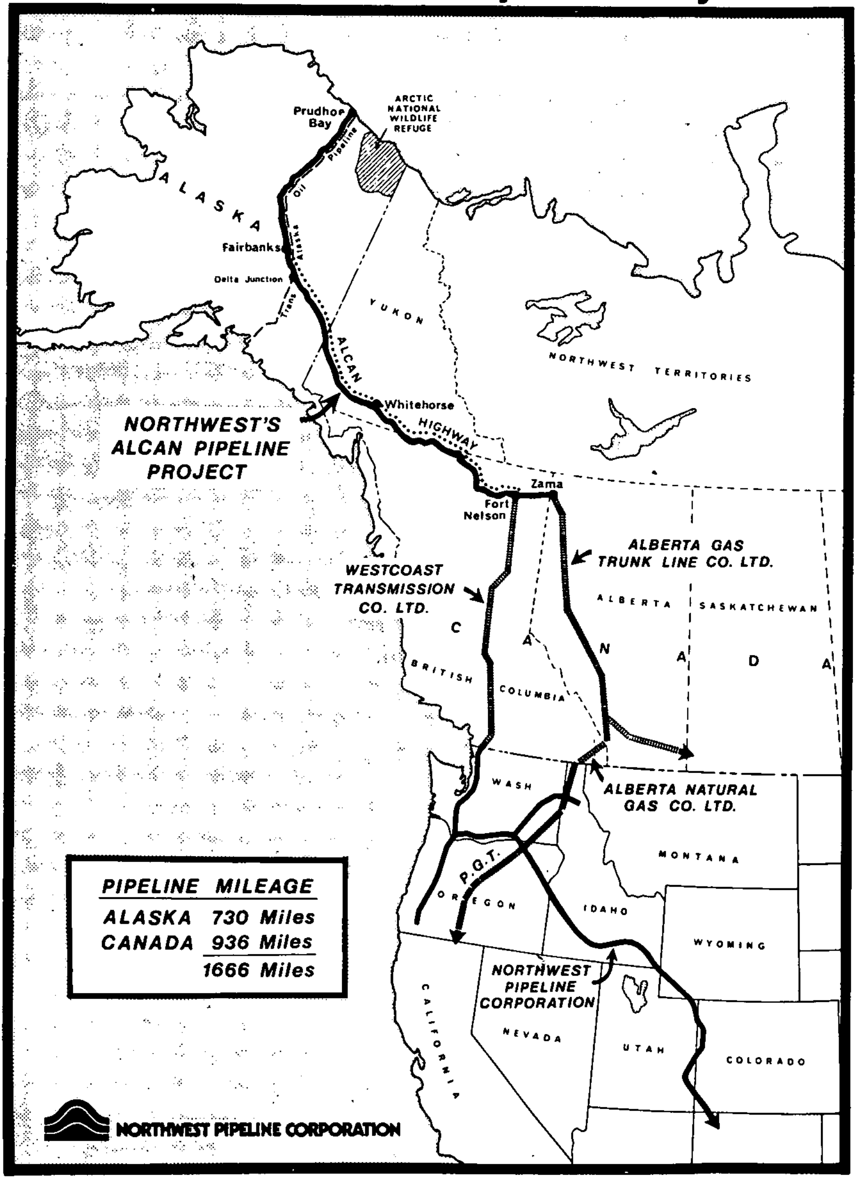
The Arctic Gas system will provide the nation an economical means for using the natural gas moved in both the near- and long-term. It also offers benefits for the future because it can be easily expanded to move greater volumes. Lastly, such a joint venture with Canada - a venture which serves the needs of both nations - is beneficial to long-term Canadian-American relations.

POTENTIAL PROBLEMS AREAS:

ENVIRONMENTAL CONCERNS are important. Several environmental groups have shown concern and opposition to the Arctic Gas system. The other two proposals have not provided supportive environmental data to indicate there are major differences. Strict environmental guidelines are established for the Arctic Gas route and have been considered by Arctic Gas and factored into its economic analysis.

DECISION MAKING: Costs for any of the three systems rise by about $1 million per day. It is important for resolution to be reached. At issue is consideration of the national interest as opposed to the interests of separate private sector organizations, state governments and individuals. Further delays will raise the cost of all three systems relatively the same. The American consumer, therefore, is hurt the most because delays do not provide a better decision; just a later decision.

# Northwest's Alcan Pipeline Project



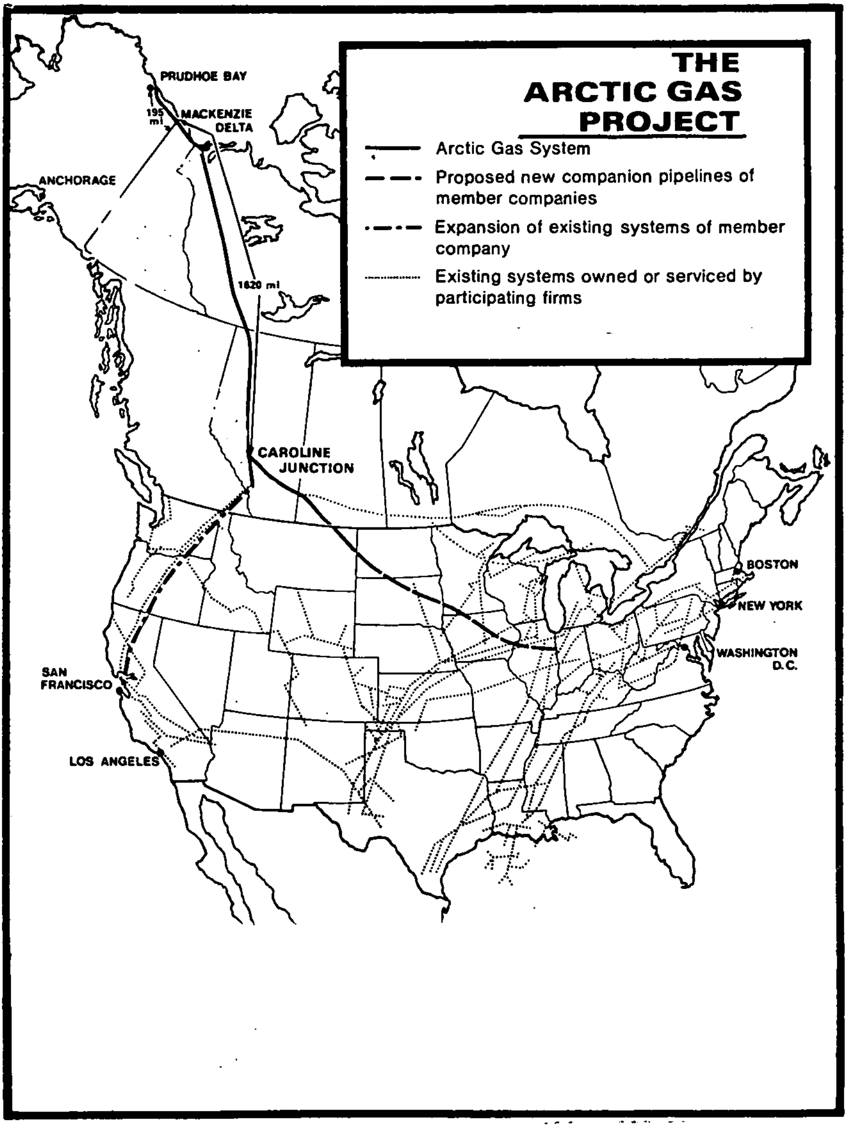
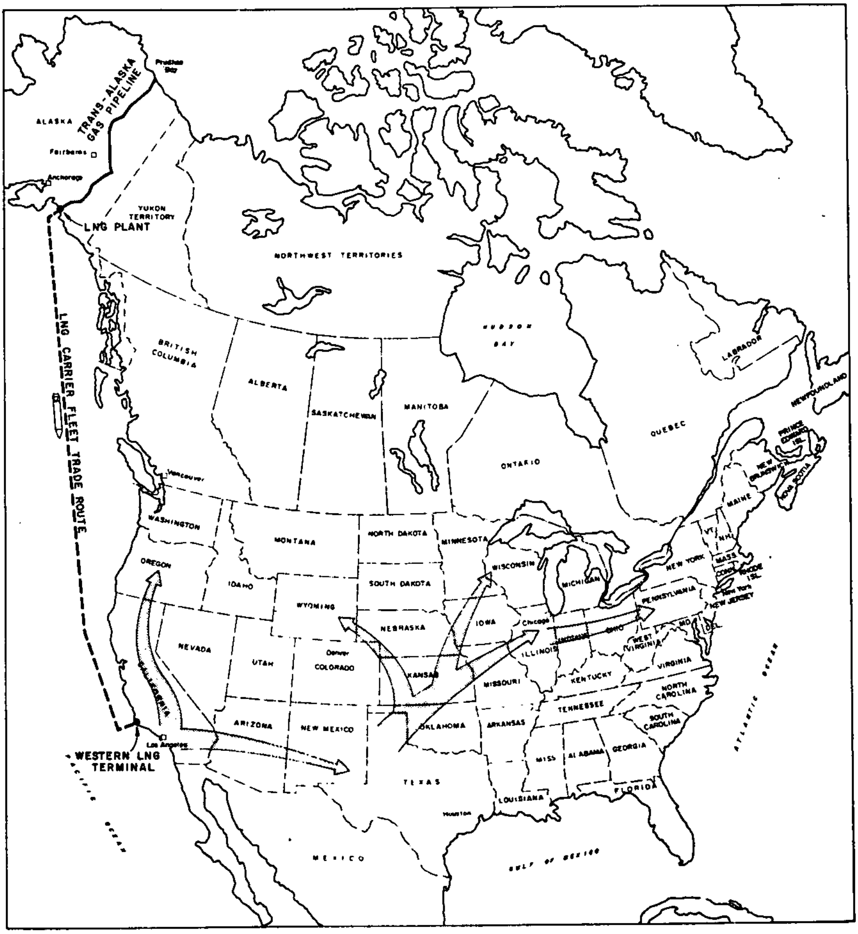

THE ARCTIC GAS PROJECT
Arctic Gas System
Proposed new companion pipelines of member companies
Expansion of existing systems of member company
Existing systems owned or serviced by participating firms
PRUDHOE BAY
195 mi
MACKENZIE DELTA
ANCHORAGE
1620 mi
CAROLINE JUNCTION
BOSTON
NEW YORK
WASHINGTON D.C.
SAN FRANCISCO
LOS ANGELES

ILLUSTRATION OF EL PASO SYSTEM




LEGEND
CONCEPTUAL GAS FLOW

## UPPER MIDWEST COUNCIL

The Upper Midwest Council was created in 1959 by a group of concerned leaders throughout the Ninth Federal Reserve District in response to needs for more information on regional socio-economic trends and options available to stimulate growth and improvement in the upper-midwest community.

The Council was established to meet a specific need for which no existing organization was responsible - to evaluate objectively significant emerging issues from a multi-state perspective. It is our belief the interest of the region will be served to the extent public and private decisions can be based on a more comprehensive and accurate understanding of the changing needs and opportunities in the Upper Midwest. Thus, the Council seeks to stimulate discussion of issues with interstate implications as well as local issues that are common throughout the region.

Our activities are designed to provide workable and useable information which will benefit planners and decision makers. We also strive to raise the level of general public understanding.

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### Recent Council Publications

Northern Great Plains Coal: Conflicts and Options in Decision Making, Michael J. Murphy, April, 1976, 284 pages, $5.00.

Northern Great Plains Coal: Issues and Options for Suppliers and Users, Michael J. Murphy, August, 1975, 128 pages, $2.50.

Land Use: Trends and Policies in the Upper Midwest, Ned Crosby, Neil Gustafson and Joe Stinchfield, February, 1976, 98 pages, $5.00.

Differing Perspectives, A Summary of the Proceedings of the Canadian-American Dialog held in the Twin Cities May 6-7, 1975, 19 pages, $1.00.

Population Mobility in the Upper Midwest: Trends, Prospects, Policies, Neil C. Gustafson and Mark Cohan, July, 1974, 40 pages, $2.00.

Recent Trends/Future Prospects: A Look at Upper Midwest Population Changes, Neil C. Gustafson, December, 1972, 69 pages, $2.00.

Chairman HUMPHREY. The escalating costs of energy are indeed alarming, no matter how optimistic you wish to be. It surely is a fact, Mr. Thiss, and I'm glad you brought that up.

Mr. THISS. Right.

Chairman HUMPHREY. I think that's one of the inevitables. Our people don't like to look ahead at that. For example, I know there's an article stating that there's a great deal of natural gas in Alberta, Canada. In fact, the Oil Daily says mounting volumes of surplus natural gas are being proved up, mostly within Alberta. According to estimates by the Alberta Gas Trunk Line, the sole transporter of fuel in the province, as much as 9 trillion cubic feet of gas might be supplied from western Canada. It goes on to say that the glut of gas is affecting the entire natural gas industry from wellheads to burner tips. So it is a very volatile industry in many ways.

The estimates change at times because of new discoveries and poor calculations, but the fact is that, while Canada continues to export its natural gas, it continues to raise the price. Furthermore, the price of domestic gas is going up as well and we have to face up to that.

How do you feel about what Mr. Millhone and Mr. Jones said about spot shortages of up to 50,000 barrels a day and the possibility of that occurring this winter?

Mr. THISS. We haven't done any direct work to tell us whether the figures are correct or incorrect, but as long as we hear of some of those figures, as Mr. Millhone presented them, it seems incumbent on us to take them under consideration and not just fall back on the fact that maybe there will not be a shortage; because we have to prepare for the worst.

Mr. HUMPHREY. In the natural gas field, our interest is not only for home heating, even though that takes a high priority. There is a conversion now by our utilities from gas to oil or coal, However, this also affects agribusiness in our processing of the products from our farms, particularly the drying and processing of our corn, soybeans, and others. What do you hear about the concerns over that?

Mr. THISS. They are very high concerns in terms of priorities and the priorities get established naturally within the State, as you well know. This is an agricultural region, this whole northern tier area. There are many parts of the agricultural process that absolutely have to have natural gas. Consequently, the priority has to be high.

Chairman HUMPHREY. We have emphasized that in the law. Has it been interpreted adequately?

Mr. THISS. The difficulty gets to be the interpretation. It is very difficult to interpret because there are enterprises and businesses that carry out agriculture or agribusiness as a part of their business, not a total part; and some parts of their business are exceedingly high in needs of natural gas. The ability of the State and the Federal Government to set priorities to meet these needs is very difficult.

It seems to us from our work that this needs continuous work, maybe high flexibility and maybe a higher relationship and more coordination between the Federal and the State Governments to achieve what you people want in terms of your priorities.

Chairman HUMPHREY. What about propane? Have you gone into that, Mr. Thiss—the availability of adequate supplies of propane gas, the possible mixture of propane with natural gas and the pricing structure?

Mr. THISS. Mr. Murphy.

Mr. MURPHY. We haven't looked at the propane question precisely, Senator. We tend to rely on what the State energy agency is doing. I don't have any comment on that.

Chairman HUMPHREY. Mr. Millhone, propane is terribly important in and around our State. Do you have any comment?

Mr. MILLHONE. Just walk on.

The propane availability is going to follow the availability of natural gas because some 70 percent of propane comes from natural gas. The need to continue, I think, the allocation program in the propane area occurs because, since propane can be used as a substitute for natural gas, larger purchasers and users may buy propane rather than paying the cost of converting to coal or petroleum products, and this buying pressure, then, would take propane away from the traditional users of propane which are home heating, crop drying, and some of these sorts of uses in rural Minnesota. So I think the propane area is one where the need to protect the present users appears to exist and the allocation program needs to be continued.

Chairman HUMPHREY. Are you keeping a close eye on that?

Mr. MILLHONE. We are.

Chairman HUMPHREY. You let us know because every time we get into any bind on this, we get a flood of calls and letters from around this State—but only when it looks as if there is a bind. Nobody ever looks ahead. They only pay attention when it hits you between the eyes.

Mr. MILLHONE. This is an area, because of the Canadian propane price being a good deal higher than the U.S. price, there is quite a price difference.

Chairman HUMPHREY. Flexibility.

Mr. MILLHONE. Price has been going up and it is something we are watching.

Chairman HUMPHREY. Thank you very much, Mr. Millhone.

On August 5, the Upper Midwest Council published an evaluation of the three competing proposals to transport Alaskan natural gas, which you commented on. The most expensive route was paralleling the Alaska Pipeline, including the use of tankers to California.

If the House passes a bill, and I think it will do so promptly and I believe the President has indicated he would sign it, it will be up to the FPC and the President to select the route. If one of the trans-Canada routes is selected, do you anticipate any problems from the Canadians in crossing their territory?

Mr. THISS. Our inclination tells us that that should be able to work itself out because it is our belief that it is in the best interest of both countries for that type of a route, especially the arctic gas one, contrary to the Alcan one, where they have the opportunity to move the natural gas into their markets. That is our belief. But it is very difficult to tell what will happen and how Governments will see things. It is hard enough in our Government, let alone what the Canadian Government visualizes. But it would make sense for the Canadian Government to move along with this decision.

Mr. MURPHY. I might point out that the Kitimat proposal for moving oil also lies in the best interest of Canada, too. It does sometime in the future, it seems to me, give opportunities for Canadian access through an expanded system for getting oil. It looks to me, if Kitimat were to become reality, it could tend to lay some groundwork for a more favorable decision on the part of Canada.

Mr. THISS. But the decisionmaking process by both countries is a very difficult one. It can't be coordinated in that sense because they are two separate, autonomous nations and the proposal we recommend does need decisions by the Canadian Government as well as by this Government. It is all the more important to make sure we get on with the decision so that they can clearly see that we are in the process of making that decision, that difficult decision.

Chairman HUMPHREY. What do you see as the earliest date we might be able to expect to have Alaskan gas available?

Mr. THISS. I think 1981, 1982.

Chairman HUMPHREY. Was that in your report?

Mr. THISS. Yes. I guess that gets back to your comment earlier, Mr. Chairman, where you mention the glut of natural gas and it is a problem that the glut will probably postpone decisions like this one and we still have to get on with this. As you mentioned in regard to propone, we don't see it until it hits us in the face. With the glut we have leadtime and then the problems get to be difficult again at a later time.

Chairman HUMPHREY. The glut may very well be what you might call regional as well. It may be a glut at the locality of the supply with inadequate means of distribution.

I think we have to be awfully careful about the terminology we use here, the sum and substance of what has been said here, starting with Mr. Zarb—that we continue to have a serious energy problem. It is a critically serious one here in the Upper Midwest and the Northern Tier area, unless we are able to move along systematically in the pipeline routes and work out our negotiations with the Canadians for whatever period of gap or transition we might have. That's what it really boils down to. We have to keep on the pressure, such as you have in the Upper Midwest Council, of pointing out what are the most desirable alternatives and what the time schedule is for meeting these alternatives.

My time schedule has run out, too, Mr. Thiss. I wish that Northwest Airlines had a plane leaving at 12:45 as it once did or 12:50, but it moved it up to 12:20, and since there are representatives here of the law enforcement agencies, I would like to stay within the speed limits.

I will have to leave, but if you have any concluding statement, we would welcome it.

Mr. THISS. Thank you very much.

Chairman HUMPHREY. Thank you.

I thank all of those who are here. You have all heard that we would welcome any further statements that any of you have. I do especially thank the witnesses for the extraordinarily well-documented prepared statements that are a part of this record.

As you know, we will analyze these statements and in due time make them available to the legislative committees of the Congress.

Thank you.

[Whereupon, at 11:50 a.m., the committee adjourned, subject to the call of the Chair.]

# APPENDIX

## Statement of Amoco Oil Co. on Northern Tier States Energy Situation

Amoco Oil Company is a major marketer of petroleum products in Minnesota and other Northern Tier states. As the owner of a 49,000 B/D landlocked refinery at Mandan, North Dakota which currently processes Canadian crude oil, Amoco is directly affected by the new Canadian crude oil export policy which calls for phase-out of all exports by 1981.

Amoco's Mandan, North Dakota refinery currently processes all available domestic North Dakota crude oil and 9,000 B/D of Canadian crude oil which is allocated to Amoco under the FEA Canadian Crude Oil Allocation Program. Mandan faces the loss of all its Canadian oil supply in 1977 because the FEA has classified it as a Priority II refinery. Yet, Mandan meets every criterion of a Priority I refinery and is uniquely dependent upon very special crude oil from Canada. But for an arbitrary restriction imposed by the FEA which states that Priority I refineries must have processed at least 25 percent Canadian crude oil in the base period, Mandan would have been classified as a Priority I refinery. During the base period Mandan processed 20.5 percent Canadian oil. It would have processed more but was unable to obtain greater Canadian supply. Mandan is a landlocked Northern Tier refinery and has no access to outside crude oil sources. Therefore, Amoco believes it is a gross inequity to treat Mandan on a different basis than all other landlocked Northern Tier refineries. In the initial Canadian allocation proposal published on November 25, 1975, the FEA classified Mandan as a Priority I refinery based on its landlocked location and inability to obtain replacement crude from alternative sources.

Unless the FEA changes the basis of its priority classifications under the Canadian Allocation Program the Mandan refinery will be forced to operate at reduced levels. This will idle some of the nation's most efficient refining capacity and will reduce the amount of Mandan products available to citizens of North Dakota and Minnesota. Minnesota currently receives over 50 percent of the output of this refinery. These products must be replaced from other sources. Since U.S. refining capacity may be limited, the loss of Mandan capacity would result in greater U.S. reliance on foreign refineries.

Until crude oil pipelines are built to supply replacement crude oil to these landlocked Northern Tier refineries they will all face crude oil shortages. Amoco has fully supported efforts of the U.S. Government and the FEA to work with the Canadian Government and NEB towards modifying the Canadian export and exchange policies in such a manner as to minimize the hardship to these Canadian-dependent landlocked refineries during the next few years. However, until something can be accomplished in this area, shortages during an interim period seem inevitable. It is appropriate that all landlocked refineries, including Amoco's Mandan refinery which have no realistic alternatives for crude oil replacement, be given equal first priority in obtaining available Canadian crude supplies. This priority would apply not only to FEA allocation of allowable exports but also to Canadian crude obtained on FEA-approved exchanges for U.S. domestic or offshore crude oils.

## Statement of Interprovincial Pipe Line, Ltd.-Lakehead Pipe Line Co., Inc.

Interprovincial Pipe Line Limited and its wholly owned U.S. subsidiary, Lakehead Pipe Line Company, Inc., own and operate a pipeline system for the transportation of crude oil and other liquid hydrocarbons. The Interprovincial/Lakehead system extends some 2,300 miles from Edmonton, Alberta, across the Canadian Prairies, through the Great Lakes region of United States to Toronto, Ontario, and Montreal, Quebec, with a lateral line to Buffalo, New York. The general location of the system is shown on the attached map.

Interprovincial is a publicly owned company with shares traded on the Toronto and Montreal stock exchanges. About 42 percent of the outstanding common stock is held by three major oil companies and the balance by some 22,000 shareholders.

The company operates as a common carrier and is engaged in the transportation of crude oil and other liquid hydrocarbons at established tariffs. Currently 37 different shippers tender crude over the system.

Since the initial pipeline was constructed in 1950 from Edmonton to Superior, Wisconsin, the system has been extended and expanded over the years. The present system is comprised of a number of separate pipelines. There are three parallel lines between Edmonton and Superior—the first is a 16-inch/18 inch/20 inch line; the second line consists of 24-inch and 26-inch pipe; the third line consists of 34-inch pipe; and a fourth line has been commenced by the installation of 330 miles of 48-inch diameter pipe in the form of 28 loops on the 34-inch line. (See map at end of statement.)

Between Superior and Sarnia, Ontario, there is a 30-inch pipeline via the Straits of Mackinac and a second line via Chicago consisting of 34-inch pipe to Chicago and 30-inch pipe from Chicago to Sarnia. In Eastern Canada there are two 20-inch lines to Toronto with a lateral line to Buffalo and the most recent addition is a 520-mile extension of 30-inch pipe from Sarnia to Montreal, just placed in service in June.

The present system has a capacity of approximately 1.5 million b/d from Western Canada with capacities of the various sections of the system noted in table form alongside the system map.

In the United States, the pipeline system has served 25 refineries in Minnesota, Wisconsin, Michigan, Illinois, Indiana and up-state New York through either direct connections or by connecting pipelines.

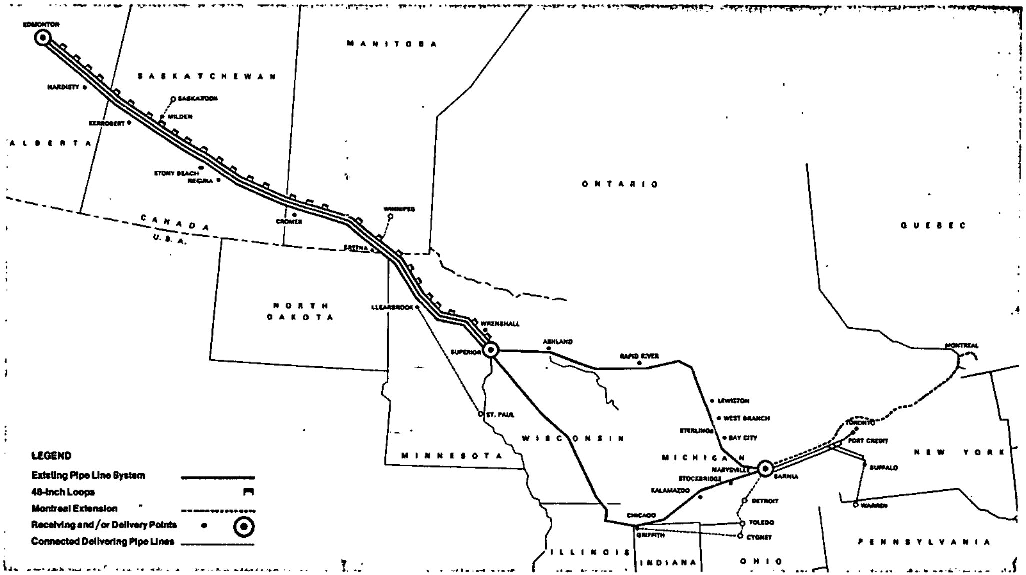
For several years the pipeline system has been transporting U.S. domestic crudes as well as Canadian. Total deliveries of Canadian crude through the systems to U.S. refineries peaked at 750,000 d/b in 1973 and with the curtailment of Canadian reports, has declined to a current level of about 290,000 d/b. The system transports a growing volume of U.S. as well as some off-shore crudes received into the system in Michigan and the Chicago area for refineries in the Detroit/Toledo and Buffalo areas. The current volume of 175,000 b/d U.S. and off-shore is expected to increase as the allowable level of Canadian exports continues to decline.

The Interprovincial/Lakehead system is in a unique position to be able to handle substantial volumes of Alaskan crude for delivery to refineries in the Upper Mid-West via either the proposed Kitimat pipeline project from Kitimat, British Columbia to Edmonton, Alberta or the proposed Northern Tier pipeline project from the State of Washington to Clearbrook, Minnesota. Use of the Interprovincial/Lakehead system with either of these proposed pipelines would provide direct access with in-place pipeline facilities to the refineries in Minnesota, Wisconsin, Michigan, the Chicago area and the Detroit/Toledo and Buffalo areas.

The existing pipeline system presently has a reserve capacity of between 300,000 and 400,000 between Edmonton, Superior and Chicago which space could be used for movement of Alaskan crude. The system can be readily expanded to accommodate additional volumes of Alaskan oil received at either Edmonton, Alberta or Clearbrook, Minnesota. Thus Interprovincial/Lakehead is in a position where receipts can be accommodated from either of the proposed new pipelines from the West Coast.

While Interprovincial is a participant in the Kitimat project group, we have also worked closely with those promoting the Northern Tier project, providing both technical advice and engineering data relative to movement in the Interprovincial system beyond Clearbrook. Our greater interest in the Kitimat proposal should be apparent, as Interprovincial obviously would benefit by the longer haul from Edmonton. However, we have indicated to both the Kitimat and Northern Tier groups that we are prepared to expand our system to handle larger volumes of Alaskan oil—assuming there is a reasonable long term supply commitment.

**INTERPROVINCIAL PIPE LINE LIMITED**
**and its United States Subsidiary**
**LAKEHEAD PIPE LINE COMPANY, INC.**




## Annual Average Physical Capacity

| Line Section | | Thousands of Barrels per Day 1976 | 1977 |
|---|---|---|---|
| Edmonton-Regina | - - | 1,513 | 1,533 |
| Regina-Cromer | - - - | 1,466 | 1,466 |
| Cromer-Superior | - - - | 1,555 | 1,555 |
| Superior-Sarnia via Straits of Mackinac | - | 450 | 450 |
| Superior-Chicago | - - | 855 | 855 |
| Chicago-Sarnia | - - - | 615 | 740 |
| Sarnia-Port Credit | - - | 470 | 470 |
| Westover-Buffalo | - - | 160 | 160 |
| Sarnia-Montreal | - - | | 350 |
| during 2nd quarter | - | 200 | |
| during 3rd quarter | - - | 350 | |

## The Pipe Line Transportation System

as at December 31, 1975
(excluding Montreal extension)

| | Canada | United States | Total |
|---|---|---|---|
| Miles of Right-of-Way | 1,004 | 1,739 | 2,743 |
| Number of Pumping Stations | 29 | 42 | 71 |
| Installed Horsepower—diesel | 37,920 | 96,335 | 134,255 |
| —electric | 485,630 | 390,500 | 876,130 |
| —total | 523,550 | 486,835 | 1,010,385 |
| Line Fill in Barrels (provided by shippers) | 11,414,000 | 11,611,000 | 23,025,000 |
| Separate Streams Transported | | | |

## Miles of Main Line Pipe

| Size | Canada | United States | Total |
|---|---|---|---|
| 12 inch | 66 | 26 | 92 |
| 16 | 397 | — | 397 |
| 18 | 39 | 325 | 364 |
| 20 | 800 | 12 | 812 |
| 24 | 772 | — | 772 |
| 26 | 2 | 325 | 327 |
| 30 | 14 | 920 | 934 |
| 34 | 774 | 789 | 1,563 |
| 48 | 224 | 106 | 330 |
| Total Miles of Main Line Pipe | 3,088 | 2,503 | 5,591 |

## Tankage: (thousands of barrels)

| | Number of tanks | Capacity |
|---|---|---|
| Edmonton | 27 | 4,645 |
| Stony Beach | 3 | 66 |
| Regina | 8 | 580 |
| Cromer | 14 | 1,006 |
| Gretna | 5 | 280 |
| Clearbrook | 7 | 474 |
| Superior | 22 | 4,584 |
| Griffith | 8 | 1,985 |
| Sarnia | 12 | 1,650 |
| Westover | 4 | 376 |
| | 110 | 15,646 |

As previously mentioned, the system could be easily expanded to handle larger volumes. For example, between Edmonton and Superior a fourth line of 48-in in diameter was started in 1972. At present, 330 miles of the approximately 1,100 miles required for a complete line have been installed with the 48-in pipe operated as loops on the present system. This system can be readily expanded by the construction of additional 48-in pipe and necessary pumping equipment. Extension of the present 48-in loops can be tailored to a specific requirement for any single year. Similarly the Superior to Chicago section could be expanded by looping this line—likely 34-in size, but a larger diameter could be considered. The easements for the existing pipeline right-of-way generally provide the right to lay an additional line.

The prime advantage of using an existing large diameter pipeline is that it can be expanded in a step-wise fashion to meet the growing demands in the markets served. Construction could be spread over several years with each annual construction program modified to meet short-term forecast requirements.

The most economic transportation system for movement of Alaskan oil surplus to West Coast requirements should make maximum use of low cost in-place facilities. We believe the Interprovincial/Lakehead pipeline system is in a key position to provide this type of transportation service.

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## Statement of Northern Tier Pipeline Co.

Mr. Chairman and members of the committee:

My name is D. Michael Curran, and I am President of Northern Tier Pipeline Company, a Montana corporation with its principal office in Billings, Montana.

Northern Tier is pleased to have the opportunity to present this testimony regarding the transportation and distribution of Alaskan crude oil to the United States.

Mr. Chairman, the problem under consideration today arises out of two situations.

One is the need for new sources of crude oil in the northern tier and central regions of the United States to replace Canadian crude oil exports which the government of Canada has announced will be totally discontinued after 1981. The refineries in these regions are partially or wholly dependent on Canadian crude oil as feedstock to run their refineries—new sources of crude must be made available so that the refineries will not be forced to shut down.

The other situation is that by late 1977 the Trans-Alaskan Pipeline should be in operation making available large quantities of crude oil from the Prudhoe Bay Fields on Alaska's North Slope. The refineries located along the Pacific Coast cannot process all of this available crude. A surplus will exist.

Therefore, the basic problem is how to get this surplus oil, as well as other required crude oils, to the deficit areas in the most effective and economic manner consistent with the interests of national security.

Northern Tier Pipeline Company offers the most feasible, economic, and embargo-proof direct mechanism to accomplish this goal.

We are preparing to build and operate a crude oil pipeline originating at a deepwater tanker terminal at Port Angeles, Washington, and extending approximately 1,500 miles across the states of Washington, Idaho Montana North Dakota and Minnesota.

At the pipeline terminus near Clearbrook, Minnesota, and at other points along the route, Northern Tier Pipeline will have the flexibility to deliver crude oil into existing pipelines which have available capacity and which are now supplying refineries in states as far south as the Kansas/Oklahoma area and as far east as New York and Pennsylvania. Most importantly, however, Northern Tier will supply those refineries that are now dependent on Canadian crude, and which will be forced to shut down unless an alternative source of crude oil is available soon. As you know, the refineries located here in the Minneapolis area are among those that will be affected.

Before Canadian supplies are eliminated, Northern Tier Pipeline Company plans to be in position to deliver new supplies of oil to every refinery needing raw material in our Northern Tier, Rocky Mountain, Mid-Continent, Mid-Western and Eastern States which heretofore have been using Canadian oil and will require an alternative and supplemental source of supply. Northern Tier Pipeline Company plans to provide a transportation facility which can assure supplies of crude oil to the affected areas thus averting potential economic hardships to the consumers, taxpayers, workers and businesses located in these regions.

Our line will have an initial capacity of 600,000 barrels per day to Clearbrook, Minnesota, with provisions for expansion to 800,000 barrels daily as demand increases. Northern Tier will have a tanker terminal located in the protected deepwater harbor at Port Angeles, Washington. This tanker terminal will have the capability to handle very large crude carriers thereby permitting maximum flexibility in economically receiving crude oil from off-shore.

I have attached as an exhibit a map of the United States showing the route of the Northern Tier Pipeline, the existing crude oil pipelines with which we will connect, and the principal refining centers which these existing lines serve. In addition, the map generally illustrates the consuming areas which are directly and indirectly affected by the Canadian cut-off of crude oil.

The dark shading shows consuming areas which have been primarily dependent on Canadian oil. The light shading indicates areas which have been using various quantities of Canadian oil and which will need alternative sources of crude oil as the cut-off takes effect.

Consumption of petroleum products in these areas is forecasted by industry economists to increase an average of about three percent per year for the next decade. As is well known, production of crude oil in the Lower 48 states is steadily declining. There is no economically comparable way other than Northern Tier Pipeline by which oil from Alaska, or other existing sources, such as the Middle East, Far East and West Africa can effectively reach the large consuming areas which are losing their Canadian supply.

A very serious situation confronts these areas, most particularly the Northern Tier and Great Lakes states. Some indication of the magnitude of the problem can be gained by examining the on-farm consumption of petroleum products used in the physical production of individual crops in only six states. For example, it has been estimated that corn and silage production alone in the states of Washington, North Dakota, Montana, Minnesota, Wisconsin and Michigan requires some 6.1 million barrels of petroleum products per year. Similarly, wheat production in the same states requires some 5 million barrels per year. Imagine the quantities involved if these two agricultural usages are extrapolated to other agricultural and industrial energy consuming sectors of the six-state area. As you are aware, the Senate is very cognizant of this problem and on June 9, 1976 passed resolution S–460 requesting the President to allocate North Slope Alaskan crude oil to the Northern Tier region of the United States. Certainly the States themselves are extremely concerned. Some indication of the depth of their concern can be obtained from the testimony of Montana Governor Tom Judge at a recent Congressional hearing. A copy of Governor Judge's testimony is attached.

More than two years ago, Mr. Chairman, following the Arab embargo of oil shipments to this country, we foresaw a worsening crude oil deficit in the Northern Tier and Great Lakes states. We began making plans to fill an economic need and gathered a team of partners within the transportation industry whose experience, industry stature and financial standing would sustain this vital project.

Thus, Northern Tier Pipeline Company was formed by seven participants; they are:

Burlington Northern Inc., St. Paul, Minnesota through its Glacier Park Company subsidiary.

Chicago, Milwaukee, St. Paul & Pacific Railroad Company, Chicago, Illinois, through its Milwaukee Land Company subsidiary.

MAPCO Inc., Tulsa, Oklahoma, a petroleum and energy company which, among other activities, owns and operates a 5500 mile products pipeline system in the southwest and north central United States.

Western Crude Oil Company, Denver, Colorado, a worldwide purchaser, marketer, and transporter of crude petroleum and petroleum products and which owns over 3500 miles of domestic U.S. pipeline facilities.

Butler Associates, Inc., Tulsa, Oklahoma, an international engineering consulting firm long experienced in designing pipelines and related facilities.

Curran Oil Company, Great Falls, Montana, which has a long background in pipeline construction.

Patrick J. McDonough, Billings, Montana, a prominent independent oil producer and investor.

One of the greatest assets of Northern Tier Pipeline Company is the knowledge, expertise, and background of its owners. The subsidiaries of the two railroads, which traverse the entire Northern Tier states from Washington to Minnesota, have knowledge of transportation matters and—very importantly—own right-of-way which may be utilized in laying our pipeline. We also anticipate utilizing existing utility power corridors wherever possible.

MAPCO, Butler Associates and Western Crude Oil all have vast experience in the design and operation of petroleum pipelines. I personally have been in the pipeline construction business for nearly 30 years. No major oil company is involved in our project.

Northern Tier Pipeline Company was incorporated in the fall of 1975, at which time we publicly announced our intentions and began preliminary engineering and route evaluations. As of today, the Northern Tier Pipeline project is well along. We have completed the preliminary engineering and design study and tentatively settled on the pipeline route.

Northern Tier has completed an economic analysis which indicates that the project is economically feasible and very competitive. The New York firm of Kidder, Peabody & Company, Inc. has been retained as Northern Tier's investment banker. Preliminary conversations with potential equity investors and debt sources have been encouraging.

Northern Tier Pipeline Company made application to the Energy Facility Siting Council of the State of Washington for authority to construct an oil port and terminal in the vicinity of Port Angeles, Clallam County, on the Olympic Peninsula, and to build a pipeline across the state. The council accepted the application and gave Northern Tier a list of questions to be answered by August 20, 1976. Replies to the questions were completed and delivered to the council on that date. Having received all of the information requested, the council has prepared a schedule of public hearings to be held in each county affected or traversed.

These hearings are currently underway. Preliminary contacts have been made with the Bureau of Land Management and the Forestry Service regarding the appropriate procedures and agency contacts necessary to facilitate any Federal permits which may be required. Future discussions with these and other Federal agencies are planned in the very near future. Work is also underway with respect to the permits and other authorizations which will be required from the various States the pipeline will traverse.

Dames & Moore, our environmental consultant, has completed a preliminary environmental assessment of the marine terminal and pipeline facilities and are in the process of performing the final in-depth study. The final E.I.S. for the State of Washington will be completed by November 1 and work is continuing on the environmental statement for the remainder of the route.

Northern Tier has obtained options to purchase some 212 acres of industrially zoned land for the storage facilities and other pertinent installations in the vicinity of Port Angeles.

In August, 1976 Western Air Maps of Lenexa, Kansas was awarded a contract to do the aerial photography of the route and to prepare a set of strip maps to be used in making the final location of the pipeline. Work is to commence immediately and is scheduled for completion within sixty days.

During the next three months we expect to complete our financing program, refine our engineering design, make a final determination of our proposed route on the basis of aerial and surface mapping which is now underway, complete Environmental Impact Statements, and initiate final filing of permit applications.

We chose initially not to seek definitive agreements with shippers, producers or refiners until we were in the position to propose something definite and entirely viable. Over the last 45 days, we have had numerous meetings with potential shippers and are encouraged by the reception which they have afforded the Northern Tier Pipeline project. We anticipate that we will be in a position to enter into formal and definitive discussions with them within 30 to 45 days.

It will take two construction seasons to complete the pipeline in the mountainous areas where work most likely will need to be suspended during the severest winter months. By obtaining permits no later than early 1977, Northern Tier Pipeline could start delivering crude oil to consumers by the spring of 1979, or approximately 24 months after start of actual construction. This schedule anticipates that once satisfactory Environmental Impact Statements have been filed and the appropriate permits issued, there will be no delays due to frivolous lawsuits, no matter how well intentioned. It should be noted that serious concerns in this regard have also been expressed by potential shippers and refiners who will use Northern Tier Pipeline. Needless to say, any unnecessary time spent in obtaining permits will cause a corresponding delay in delivering much needed crude oil to consumers.

Northern Tier Pipeline will require some 635,000 tons of pipe and the project's total capital cost is estimated to approximate 1.1 billion dollars. During construction, we estimate that approximately 3,500 to 4,000 workers will be employed at the port facility and along the pipeline route with an annual payroll of some 75 to 90 million dollars. Once in operation, it has been estimated that Northern Tier will, directly and indirectly, create some 500 permanent jobs with an annual payroll of 11 million dollars. In addition, Alaskan crude oil coming to the United States will, we presume, be carried in American bottoms using American crews in compliance with the Jones Act.

Northern Tier Pipeline will be a common carrier, available to any and all shippers. Appropriate tariffs will be duly published and timely filed with the Interstate Commerce Commission. At present, we anticipate that these tariffs from Port Angeles eastward (and including terminalling) will approximate 51 cents per barrel to the Glacier Pipeline, just north of Billings; 64 cents per barrel to Butte Pipeline; 75 cents to Mandan, North Dakota; 90 cents to Clearbrook, Minnesota; $1.07 to Minneapolis, Minnesota and $1.18 to Chicago, Illinois.

During the past few months, interest in the Northern Tier Project has intensified. This is due in large part to the fact that the actual existence of a surplus of Alaskan crude on the West Coast becomes closer every day. The Alaskan Pipeline should be completed and in operation sometime in 1977. Two other groups are investigating pipelines to move this Alaskan surplus.

One project is called the Sohio Project and involves the building of a port facility in the Los Angeles area and moving the oil by a pipeline to Midland, Texas and then to the Texas Gulf Coast for refining. This project does nothing to alleviate the crude oil shortage projected for the Northern Tier States. The cost of delivering Alaskan oil through this system to Chicago would be prohibitive.

The other project is called the Trans-Provincial Project which calls for construction of a pipeline from Kitimat, British Columbia to Edmonton, Alberta. Through existing systems, oil could be moved form there into a portion of the Northern Tier States, but not all. This project is in the nature of a stop-gap or temporary solution in that a through-put of only 300,000 barrels per day is planned. The project, by its very nature, would be under the absolute control of the Canadian Provincial Governments, as well as the Canadian National Government. Recently, the Canadians have abrogated and refused to honor their long-term contractual commitments for natural gas supply to many of the Northern Tier States. Based upon this performance, or lack thereof, we believe it is dangerous to assume that any long-term agreements for the transport of Alaskan oil would be honored. Furthermore, we do not believe that Alaskan or domestic crude oil supply for eight million Americans in the Lower 48 States should be under the jurisdiction of a foreign power if it can be avoided.

The Science Council of Canada offered just this past week this dispassionate review and report. I quote, "A critical energy supply situation is now developing despite reduced oil and gas exports * * * by 1990 there will be a dramatic change in the net oil situation of today. There will be an enormous gap between supply and demand." This report, in our opinion, has dangerous implications with regard to dependence upon Canadian pipelines to move crude oil to United States refining centers. The Canadians will require these systems to move crude oil to their own interior refining centers. I would also like to make part of the record an article from the August, 1976 issue of Fortune Magazine entitled: "Canada's Nationalism Exacts a High Price" by Herbert E. Mayer. It requires no editorial comment from us.

I would now like to return, for the moment, to the subject of tariffs. As mentioned, the Sohio Project really does not solve the northern tier problem so their tariffs are not germane to this discussion. In recent testimony, the Trans-Provincial group stated that their *average* tariff from Kitimat to Edmonton would be 66¢ but that their early years tariff would range between 77¢ and 80¢ per barrel. However, even if we assume that Trans-Provincial's start-up tariff from Kitimat to Edmonton were 66¢, a comparison of that project's tariffs to those of Northern Tier Pipeline is as follows:

[In dollars per barrel]

| To— | From Port Angeles, Wash. | From Kitimat, British Columbia |
|---|---|---|
| North Bend | 0.11 | |
| Glacier pipeline | .51 | |
| Butte pipeline | .64 | |
| Mandan | .75 | |
| Clearbrook | .90 | 1.01 |
| Superior/Wrenshall | 1.02 | 1.08 |
| Twin Cities | 1.07 | 1.18 |
| Chicago | 1.18 | 1.21 |
| Marysville | 1.22 | 1.24 |
| Buffalo | 1.[illegible] | 1.37 |

It should be noted that no tariffs are provided by Trans-Provincial to either Billings or Mandan; the areas which will be most severely affected by the Canadian oil cut-off. Had there been, they would be significantly higher than the Northern Tier tariffs to those points; perhaps twice as high. In effect, Trans-Provincial is proposing a Canadian system which will result in higher energy costs to parts of the U.S. Northern Tier States than might otherwise be achieved.

The recently published F.E.A. report to the Senate entitled Crude Supply Alternatives for the Northern Tier States sets out some tariff data which differs from that presented above. It should be noted that many of the tariffs presented in the F.E.A. report are theoretical tariffs based upon hypothetical pipeline systems, none of which represent the pipelines actually proposed to be built. This report is very misleading in this respect.

In conclusion, Mr. Chairman, let me say that Northern Tier Pipeline Company studied several sites for a port facility on the Pacific Coast, and several alternate pipeline routes and engineering designs. We are convinced that we have settled on a project with the optimum economic, technical, and environmental considerations.

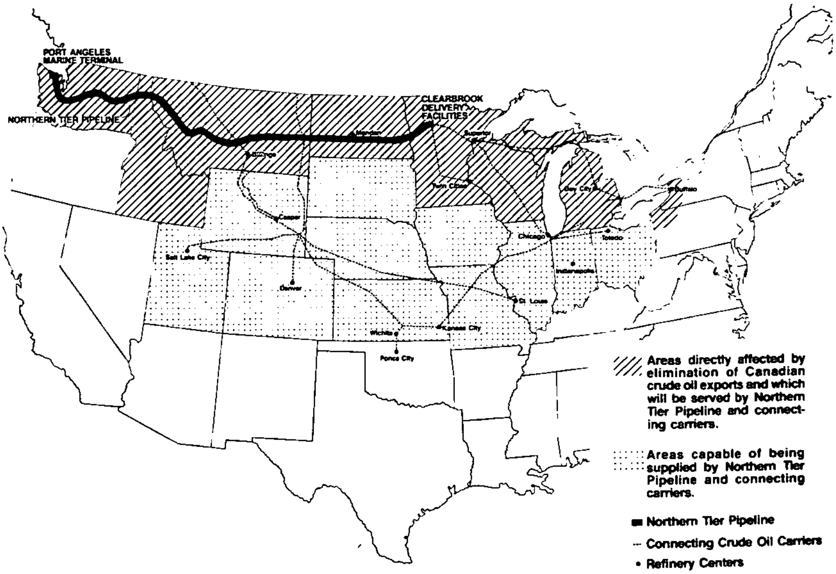
Northern Tier will be a direct route, able to serve every one of the states now using Canadian oil. In addition, Northern Tier will have the capacity to supply refiners as far south as Kansas and Oklahoma, as far southwest as Salt Lake City, and as far east as New York and Pennsylvania through interconnecting pipelines. In effect, Northern Tier Pipeline will have the capability to directly or indirectly reach refiners having a rated daily capacity of some 4.5 million barrels—approximately one-fourth of U.S. domestic refining capacity. Our contacts with refiners indicate that a substantial number of these can use Alaskan crude oil without significant modification.

Northern Tier will be an all-new line. Ours is the most efficient route between the source of oil and the place where it is needed the most with the lowest net energy consumption.

If all goes well, Mr. Chairman, by the time Canadian oil is entirely cut off, Northern Tier Pipeline Company will be supplying the vast consuming area within the center of our nation with domestic American crude oil from Alaska via an all-new, all-American, direct pipeline built with American capital, by American enterprise, and employing American workers paying American taxes.

I thank the committee for permitting me to make this presentation.

Attachments.




Testimony by Hon. Thomas L. Judge, Governor, State of Montana, Presented to the Subcommittee on Public Lands, House Interior Committee, Congressman John Melcher, Chairman, Billings, Mont., September 8, 1976

### MONTANA REFINERY FEEDSTOCKS: CANADIAN CURTAILMENTS AND SUPPLY ALTERNATIVES

Good afternoon. It is a pleasure to be here in Billings testifying before a Congressional committee, rather than in Washington, D.C. The problem of the Canadian curtailment of our refinery feedstocks is a very important one to Montana, and I appreciate being given the opportunity to make our situation and position clear. In my testimony I will briefly outline the situation we face in Montana, discuss several pertinent aspects of the alternatives available to us, and present some conclusions and recommendations. I would like to enter into the record two Montana Energy Advisory Council staff papers which supplement my testimony. They are "Montana Petroleum Situation," Montana Energy Advisory Council Staff Paper 76–1, and "The Economic Importance of Montana Refineries and Projected Impacts of Curtailments in Canadian Petroleum Imports," prepared for the Montana Energy Advisory Council by the Montana Bureau of Business and Economic Research.[1] At the time these reports were prepared, it was the objective of the participants to accumulate a data base without prejudice which would in turn assist the State of Montana in arriving at policy decisions.

*Montana petroleum situation*

In the last five years, Montana crude oil production has been relatively stable at about 34 million barrels per year. Montana proven reserves of crude petroleum as of December 31, 1975, are estimated at from 164 million barrels to 255 million barrels. At 1975 production levels, this would leave the state with from five to seven years of production before presently-known recoverable reserves are depleted. Due to transportation limitations, only about 36 per cent of these known serves are available to the major Montana refineries. If all of this faction of total reserves were immediately available and used by Montana refineries, it would represent less than two years supply at current rates of crude oil throughput.

Montana both imports and exports large volumes of crude oil. In 1975 the source of total crude refined in Montana was 17 per cent from Montana production, 40 per cent from Wyoming and 43 per cent from Canada.

[1] See hearing record of Sept. 8, 1976, for staff papers presented for the record before the Subcommittee on Public Lands, House Interior Committee, 94th Congress, second session.

Production of crude oil from Northern, Central and Southcentral Montana, the areas that supply Montana refineries, has been relatively stable over the past three decades, accounting for only about 30 percent of total Montana production in recent years. Major discoveries of crude reserves in the Williston Basin in 1951 and the Powder River Basin in 1967 imposed substantial changes on the state's crude production picture. However, crude produced from these two areas is almost totally dedicated to export, since no pipelines exist to transport it to the major refineries in the Billings area.

The three Billings area refineries have accounted for nearly 90 percent of total Montana refinery output in recent years. All these refineries are heavily dependent on imported Canadian crude oil. The Continental Oil refinery in Billings, in addition to receiving Canadian crude oil, relies for almost one-third of its total inputs on imported Canadian natural gas condensates. Import of Canadian feedstocks to Montana began in 1962 with the completion of the Glacier pipeline system. Reliance on Canadian inputs has steadily increased, as the refineries expanded and adjusted to the lighter and sweeter (lower sulfur content) Canadian crude oil and condensates. Annual importation of Canadian crude oil and condensates reached a peak of 24.3 million barrels in 1973 and declined slightly to 20.7 million barrels in 1975.

As we know, the Canadian feedstock is a very uncertain source for the future, since the National Energy Board of Canada has announced plans to completely curtail exports of crude oil to United States refineries. This curtailment has already begun. From a peak export level of over a million barrels a day in 1973, the Canadian exports are now scheduled to reach ten per cent of that level by the end of 1978, and zero by 1982.

*Longer term supply alternatives for Montana*

Looking only at the effects of refinery closings, Montana would suffer a loss of between 2,115 and 2,755 workers (primary plus derivative) if the Canadian crude oil is curtailed and no replacement made. We have not estimated the economic and social costs of cutting off our petroleum products. Here in Yellowstone County alone, total employment could decline between 3.7 and 4.8 per cent just due to the loss of Canadian feedstocks. The loss of these important jobs is simply not acceptable. We must have a replacement for the Canadian crude oil and condensates.

In our assessment of the options, only the Northern Tier Pipeline appears to offer a viable alternative to the Canadian supply situation. The Northern Tier Pipeline and Trans-provincial pipeline (and some other alternatives which would only serve the Central Northern Tier states) have been examined in a Federal Energy Administration study which was submitted to the United States Senate last month. We worked with the Federal Energy Administration and their consultant as the study was carried out, and we have some familiarity with it. We believe that the Federal Energy Administration effort has assembled some useful information; however, it has severe limitations if it is to be used as the primary basis for the setting of federal policy. The Federal Energy Administration study is particularly weak in its considertion of interactive and timing factors of the alternatives, and in the cost comparisons.

A question of major concern involves the international dimensions of placing our petroleum supply under the control of a foreign nation. Construction of the Trans-provincial pipeline would occur completely on Canadian soil. The initialed, but not yet signed, United States/Canadian Pipeline Treaty would appear to provide some assurances that our hydrocarbons in transit would not be arbitrarily cut off. Hydrocarbons from international sources bound for eastern Canada now transit the state of Maine, and they thus have a similar dependence on us; however, there will of necessity be major supply uncertainty tied to international politics if this line is built.

Exchanges of crude oil have been frequently suggested as both short and long-term solutions to our problem. Such exchanges would obviate the need for a massive capital investment and the associated costs, however, it appears that this is inconsistent with Canadian national energy policy.

From Montanas' point of view, new jobs and tax revenues accruing from Northern Tier Pipeline construction and operation cannot be overlooked. The combined primary and derivative effects of construction of the Northern Tier Pipeline would amount to an estimated 1,950 to 2,660 jobs for each of two years of construction, and would produce an estimated $29,600,000 per year new (total) earnings for each year as well (expressed in 1973 dollars). The annual effects in the operational phase will amount to an estimated 48 to 63 total workers and total earnings of $427,700. We have not estimated tax revenues produced by the pipeline, but they certainly could be important to those counties whose property tax base would be enlarged.

*Conclusions and recommendations*

Gentlemen, I feel that it would be a criminal act for SOHIO to be allowed to move Alaskan crude oil to refineries on the Texas Gulf—that would be like hauling coals to Newcastle. We in Montana and the Northern Tier states are experiencing a crude oil supply crisis. We feel this crisis can only be eliminated by a supply of Alaskan crude oil which cannot be cut off by an OPEC embargo. I believe that the intent of the law that was passed by Congress when the Alyeska Pipeline was given its permit was to the effect that Alaskan crude oil should be equitably distributed in the lower 48 states. I do not believe that Alaskan crude is really needed or required in Texas. It is needed in Montana and the Northern Tier states—and badly needed. Should the SOHIO pipeline be given a permit by the Department of Interior, the State of Montana will call on all of our legal resources to see to it that this permit be rejected. Alaska will be our only firm source of crude supply, and the Alaskan West Coast surplus should be allocated to Montana and the Northern Tier states.

In regard ot the Trans-provincial pipeline, which would be built in Canada, our recent experience with the Canadian federal and provincial government in honoring long-term natural gas contracts has been devastating. The Canadians have arbitrarily increased the price from 32¢ per thousand cubic feet in 1972 to $1.94 per thousand cubic feet this coming January at the border—a 600 percent increase in four years! This increase will have a serious impact on Montana business, industry, and the home-owners in the Montana Power Company service area. Alberta natural gas at the well-head will sell for approximately 72¢ per thousand cubic feet in January. Transported all across Canda to Toronto, it will sell at city gate on January 1 for $1.50½. Every state in the United States will be paying over $2.00 per thousand cubic feet. That is an incredible situation when you consider that the natural gas fields in Alberta lie close to the Montana border.

Another disastrous situation is the curtailment by the Canadian National Energy Board of long-existing contracts between the Montana Power Company and their supplier in Canada. In 1975, the National Energy Board curtailed 10 billion cubic feet of natural gas per year to Montana. Last year, they curtailed another 5 billion cubic feet, and they are proposing to cut back another 5 billion cubic feet next May. If the Canadian federal government continues to curtail our supply of natural gas, it will mean the cancellation of industrial contracts and no new residential hookups. These industries in western Montana employ 10,000 workers who could be out of a job because of arbitrary, capricious actions of the Canadian federal government. The curtailment of Canadian crude oil to the United States was a greater percentage than the Arab Oil Embargo. For years we have enjoyed close and friendly ties with our good neighbors in Canada, but that is changing with irresponsible actions and policies of the Canadian national government. In view of our experience, how can the U.S. government seriously give any consideration to a proposal to bring American crude oil through Canada?

I strongly oppose both the proposed SOHIO and Trans-provincial pipelines. I enthusiastically endorse the construction of the Northern Tier Pipeline, and I urge Congress to act in any way possible to immediately expedite its construction.

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[From Fortune magazine, August 1976]

CANADA'S NATIONALISM EXACTS A HIGH PRICE

(By Herbert E. Mayer)

For four years now, the Canadian government has been trying to loosen Canada's economic ties to the U.S. The effort has met with only modest success; some of the ties between the two countries seem tighter today than they were in 1972. But it is increasingly clear that attempts to loosen the U.S. connection have vastly expanded the role of government in the Canadian economy. In fact, Canadian businessmen are now worried that the price of economic nationalism may be their own freedom of operation.

The concentration of economic control and policy in the hands of a highly centralized government has come at a time when the economy is dangerously weak. Rising wage rates, high inflation, and low productivity gains are all eating away at Canada's export position, especially in the U.S. market. That's bad news indeed for a country whose economic health rests so completely upon its ability to sell products abroad.

Economic trouble is especially dangerous for Canada because any sustained decline in the general standard of living must inevitably aggravate the internal political struggles—among the ten provinces, and between the provinces and Ottawa—that have always kept this vast, resource-wealthy land from realizing its extraordinary potential. The provinces are so different, so independent, so much at odds with each other and with Ottawa, that it is hardly an exaggeration to describe Canada not as a country, but rather as an idea for a country that has not yet come into being.

### THE MIDDLE OF THE ROAD IS EMPTY

The divisions among the provinces are of several kinds—cultural and economical, as well as political. In the French-speaking province of Quebec, for example, a separatist movement is dormant but by no means dead. A lot of people in Quebec, and elsewhere in Canada, want to see this troubled, sometimes violent province leave the confederation. Out in the western provinces, dislike for Quebec is exceeded only by distrust and even loathing felt for Ontario, the richest and most powerful province. With 42 percent of Canada's manufacturing and 28 percent of its farm income, Ontario is regarded elsewhere in the country with the mixture of jealousy and contempt some Americans have for New York, only more so.

Politically, the middle of the road is a fairly empty place in Canada's provinces. Voters in British Columbia elected a socialist government in 1972 (and voted it out in 1975), and a socialist government in Saskatchewan is taking over the province's potash mines. But Alberta, in the Rocky Mountain region, has vast oil reserves, and a government that is as capitalistic and growth-oriented as they come. To a degree that often surprises Americans who mistakenly equate Canadian provinces with U.S. states, the provinces have the political power to set their own courses. They often do it with little regard for each other, and less for Ottawa. Think of Canada as a collection of notes; do not think of it as music.

THE U.S. STAKE IN CANADA'S LARGEST INDUSTRIAL COMPANIES

[Dollars in thousands]

| Rank in Canada | 500 rank | Company | 1975 sales | U.S. share (percent) |
|---|---|---|---|---|
| 1 | 35 | Ford Motor of Canada | $4,363,331 | 88.0 |
| 2 | 38 | General Motors of Canada | 4,262,365 | 100.0 |
| 3 | 46 | Imperial Oil | 3,978,999 | 69.5 |
| 4 | 85 | Massey-Ferguson | 2,513,302 | 35.4 |
| 5 | 88 | Chrysler Canada | 2,431,985 | 100.0 |
| 6 | 92 | Alcan Aluminium | 2,301,453 | 38.4 |
| 7 | 126 | Gulf Oil Canada | 1,700,833 | 68.2 |
| 8 | 127 | Inco | 1,694,768 | 37.0 |
| 9 | 147 | Canada Packers | 1,479,492 | 2.0 |
| 10 | 168 | MacMillan Bloedel | 1,274,901 | 12.9 |
| 11 | 180 | Steel Co. of Canada | 1,181,563 | 2.2 |
| 12 | 188 | Noranda Mines | 1,136,992 | 4.0 |
| 13 | 214 | Moore | 1,005,610 | 36.2 |
| 14 | 216 | Northern Telecom | 1,001,270 | 8.7 |
| 15 | 220 | Seagram | 977,430 | 13.2 |
| 16 | 247 | Texaco Canada | 850,016 | 68.2 |
| 17 | 258 | Canadian General Electric | 808,320 | 91.9 |
| 18 | 261 | Domtar | 801,523 | 2.5 |
| 19 | 284 | Abitibi Paper | 751,540 | 8.0 |
| 20 | 291 | Cominco | 733,645 | 2.1 |
| 21 | 294 | Dominion Foundries & Steel | 725,681 | 2.4 |
| 22 | 299 | Genstar | 708,000 | 10.0 |
| 23 | 319 | Consolidated-Bathurst | 632,903 | .1 |
| 24 | 326 | Molson | 624,503 | .4 |
| 25 | 332 | Burns Foods | 611,630 | .3 |

Note.—This list of the 25 largest industrial corporations in Canada is drawn from the Fortune Directory of the 500 Largest Industrials Outside the United States (p. 232). Canadians control even less of these companies than the numbers indicate. That's because some shares are owned by investors who are neither Canadian nor American. Moreover, the American ownership figures represent shares owned by the U.S. parent, and do not include stock in the hands of other private investors. Sales are in U.S. dollars.

As so often happens when a country is divided internally, an overpowering urge develops to unite against a common enemy or what is perceived as one. For Canadians, the large, powerful, and dynamic U.S. has always been a most appealing villain. It is close enough to put the smaller country in a permanent shadow, big enough to hit at will, and too big to really feel the blows or become angry enough to hit back.

Canadians have been tweaking the eagle's tail feathers for a century, but it was not until 1972 that the government made nationalism an official policy. Since this policy is utterly devoted to permanently changing the U.S.-Canadian relationship, it is especially important to understand the Canadian perception of this relationship as it now stands. Prime Minister Pierre Trudeau is fond of describing Canada as a mouse in bed with an elephant, and the analogy is not without merit. U.S. companies control 36 percent of Canada's paper and pulp industry, 43 percent of its mining and smelting industry, 45 percent of its manufacturing industry, and 58 percent of its oil and natural-gas industry. Of the 100 largest companies in Canada, forty are American-owned.

It is a cliché in Canada that extensive U S. investment, which totals about $30 billion, has turned the country into a branch-plant economy. Sixty-six percent of Canada's $32 billion worth of exports in 1975 went to the U.S. And of the $34.6 billion of goods and services that Canada imported last year, 68 percent came from the U.S. This makes Canada by far the United States' best trading partner. So tight is this partnership that the two economies have historically performed in tandem, the smaller one trailing the larger by several months. Canadian economists say they look at the U.S. to see where they are going, and U.S. economists can look north to see where they've just been.

America's cultural influence in Canada is as pervasive as its economic influence. An overwhelming majority of books and magazines sold at Canadian newsstands are of U.S. origin.[1] Since 90 percent of all Canadians live within 200 miles of the U.S. border, American television shows are readily available and extremely popular. American films and hit records fairly dominate the Canadian market, and virtually every brand-name American product is available to Canadian shoppers.

### THE TALENT MOVED SOUTH

Canadian nationalists argue that America's overwhelming influence and wealth often work to Canada's disadvantage. They point out, accurately, that U.S. companies with plants in Canada have a tendency to layoff workers at those plants before cutting back production at plants in the States. And they complain that the higher salaries and vastly greater opportunities for advancement available in the U.S., especially in the worlds of business and art, have drained Canada of some top-quality talent that might otherwise have stayed at home and contributed to Canada's development and glory.

John Kenneth Jamieson, the former chairman of Exxon, was born and raised in Medicine Hat. Cyrus Eaton was a Canadian, too: So were James L. Kraft, who came to Chicago in 1903 and founded a cheese company. Alfred C. Fuller, who arrived the same year and got into brushes and Elizabeth Arden, who was born in Ontario. The list of Canadian-Americans includes John Kenneth Galbraith, the economist; S. J. Hayakawa, formerly president of San Francisco State College and now a Republican candidate for the U.S. Senate, and novelist Saul Bellow. Raymond Massey, the actor, comes from the Toronto family that founded Massey-Ferguson, the farm-machinery company. Mary Pickford was born in Canada, and so was Jay Silverheels, better known to a generation of Americans as the Lone Ranger's Tonto.

The tendency of U.S. companies to shut down their Canadian plants first is irritating and obviously unpleasant for Canadian workers, but thoughtful Canadians understand that if it had not been for U.S. investment, those jobs would probably not have been there in the first place. And they readily admit that Messrs. Kraft and Fuller could not have built their empires in a market as small as Canada's; that nothing could have kept an actor destined to portray *Abe Lincoln in Illinois* away from Broadway and Hollywood. In fact, all but the most fanatical Canadian nationalists concede that their country's close relationship with the U.S. has, on balance, been a very profitable one for Canada. They know full well

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[1] The magazine with the largest paid circulation in Canada is American-owned Reader' Digest. Time, the fourth-largest magazine in Canada, is published by Time Inc., which also publishes Fortune. Changes in Canadian law forced the suspension of Time's special Canadian edition earlier this year.

that only by riding the back of the powerful U.S. economy has their country of just 22 million people—roughly the population of California—been able to achieve a standard of living that equals the U.S. standard.

The problem with the U.S.-Canadian relationship is not so much what it is today, Canadians emphasize, but rather with what it might become. They argue that no intelligent mouse, however warm and comfortable, can be blind to the awful possibility of being injured or even crushed should the elephant beside it get angry, or simply forget the mouse is there and roll over on it. Fair enough. But how best can the mouse assure its safety?

### GRAVITY AT THE EDGE OF THE BED

In the fall of 1972, Mitchell Sharp, then Canada's secretary of state for external affairs, outlined three options for Canada. The first was to maintain the country's existing relationship with the U.S. and (so to speak, hope for the best. The second was to move deliberately toward even closer integration with the U.S., which would increase the risk but also increase the benefits. And the third option—the one Sharp told Canadians their government was adopting as the cornerstone of its policy—was "to pursue a comprehensive long-term strategy to develop and strengthen the Canadian economy and other aspects of its natural life and in the process to reduce the present Canadian vulnerability." In language less diplomatic, Canada was going to move its pillow further toward the edge of the bed.

Now, one need not actually have had the experience of sleeping with an elephant to recognize that any attempt to move toward the bed's edge would be an uphill struggle. Gravity pulls you back toward the center. Likewise for any Canadian effort to put some distance between Canada and the U.S., for the American economy and culture have an almost gravitational attraction to many Canadians and Canadian organizations.

Moreover, nationalism was by no means the only force at work in Canada. The provinces were pulling in assorted directions, and the country's business community actively opposed the third option. Most businessmen favored letting market forces determine the U.S.-Canadian relationship, and those forces were likely to make the links even tighter. In any case, Canadian businessmen had neither the capital nor the inclination to buy out U.S.-owned companies; only the government could afford to do it. But the federal government would need much more power than it had to make the third-option policy work—enough power to overcome any opposition and attain sufficient thrust to blast Canada beyond the gravitational reach of the U.S.

### "THE SYSTEM IS OUT OF JOINT"

The man at the vortex of all the forces in Canada—rather like the sun around which all the planets in a galaxy revolve—is Pierre Elliott Trudeau, the controversial, contradictory, undeniably charismatic prime minister whose policies and personality have dominated Canadian political life since 1968. Today, because of Canada's economic troubles, even more attention than usual is focused on the prime minister. After winning the 1974 elections largely on his opposition to the idea of controls on wages and profits, he stunned the country last October 13 by imposing them.

When the controls program was announced, most Canadians assumed that Trudeau's only purpose was to provide a shock that would somehow jolt the economy off its downward course. He put a 12 percent ceiling on wage increases, and companies were ordered to reduce their profit margins to a ceiling equal to 95 percent of those margins during the last five years. This percentage has since been lowered further, to 85 percent.

It was not until the closing days of 1975 that Canadians learned how their prime minister viewed the controls program—not as a temporary evil, but rather as a prelude to permanent changes in the role of government in Canada. The occasion was a year-end television interview. A comment by Trudeau that the need for controls proved "the system is out of joint" prompted an interviewer to ask whether the prime minister thought "bigness" was the source of Canada's economic problems.

Trudeau agreed that it was, and then went on to explain precisely what he had in mind to do about it. "We can't destroy the big unions and we can't destroy the multinationals," he said. "We can control them—but who can control them? The government. This means that government is going to take a larger role in running institutions . . . even after the controls are ended . . . It means there's going to be not less authority in our lives but perhaps more."

In a recent interview with Fortune, Trudeau talked about his philosophy and about his plans to expand the role of government in the Canadian economy. The conversation took place in the prime minister's small, elegant office on Parliament Hill, just off the House of Commons visitors' gallery. Trudeau, a slightly built, athletic man who looks much younger than his age (fifty-six), sat in a beige suede chair behind a hand-carved wood desk that sported a matching suede surface. A former law professor and the son of a millionaire businessman—his father, a lawyer, owned an auto-service business, said to be worth $1.4 million, that he sold to Imperial Oil in 1931—Trudeau is obviously comfortable in the job he has held for eight tumultuous years. He leaves no doubt that he intends to pursue his policies despite opposition from businessmen—especially bankers.

THE SOUND OF GALBRAITH

"When they put me in the bag as a socialist, I begin to wonder if they're kidding or if their vision of socialism isn't so wide that they'd accept only an Adam Smith liberal," the prime minister said heatedly. "Do they honestly think our economy can work in an absolutely free market? It's obvious that we don't have a pure free market in Canada and probably never did."

Although Trudeau denies he has been much influenced by the works of John Kenneth Galbraith, his analysis of how large corporations and big unions connive to circumvent market forces matches the Galbraith analysis almost to the word. "If the free-market system worked well," argues Trudeau, "in areas of overproduction or economic slowdowns, companies would be cutting prices and cutting their salaries—which they're not. The corporations themselves are not obeying the rules of the market. The consumer is not, in a period of slowdown, buying cheaper goods. He's buying at the same price. And there are fewer layoffs, and certainly you don't see wages going down any more in a period of recession. Presumably there's a sweetheart deal between some unions and some corporations to pass the costs on to the consumers and keep the prices up."

In Trudeau's view, businessmen object to government intervention only when the government's actions are not the ones that businessmen want. "In the same week that the bankers were complaining that I was interfering in the market system, there was a group of bankers enjoining us to change the Bank Act to give them much greater protection [from competition] . . . So how can you expect me to take them seriously when they say the government shouldn't be regulating the economy?"

Trudeau believes that it is the responsibility of government to step in where free enterprise fails—in the area of matching people with jobs. "We've got high inflation and high unemployment in our industrialized societies. In Canada's case we've got unemployment at 6.9 percent now and we've got inflation down to 8.9 percent. Both we consider too high. How do you put the unemployed to work? Is the market putting these unemployed together with the work that needs to be done?

"And what do the bankers say about that? I'll tell you what they say. They say the government should step back. It's too much meddling that is causing these problems. My hands fall at that point. If they think the coexistence of high inflation and high unemployment is Pierre Trudeau's fault, well, it's happening in other countries, some of which are socialist, some of which are Tory, some of which are republican, some of which are liberal. It's a problem not solved by ideological accusations." But the prime minister lets loose one scathing accusation of his own: "The worst bitchers of all are the bankers. They've never had it so good as under my government. I'm ashamed they've been making profits way ahead of the secondary manufacturing and service sector, the industrial sector, and the natural-resource sector."

Trudeau's reasoning has led him to the belief that "structural changes" need to be made in Canada's economic system. "The public interest requires government to play a coordinating role in economic planning," he says. "The changes we will make are designed to enable government to play this role." The prime minister says he'll announce some of these changes this fall.

OTTAWA CONSTRUCTS A FORUM

A few deails about those impending changes have been revealed by other government officials. Donald S. MacDonald, Trudeau's powerful and ebullient finance minister, says Ottawa plans to increase its powers to regulate a wide range of business activities—especially the activities of banks, including foreign banks operating in Canada. In addition, says MacDonald, the federal govenment will vote itself increased powers to "coordinate" access by private corporations and provincial governments to the capital markets.

One of MacDonald's colleagues in the Cabinet, Donald Jamieson, minister of industry, trade, and commerce, says that the planned structural changes will give Ottawa a big role in "priority setting" for the entire process of economic development. Jamieson is certainly not about to leave something as important as economic development to Canada's business community. The minister recently told a group of Dallas executives that most Canadian companies "are small and have limited management talent and financial influence, which calls for substantial government involvement in their affairs."

The groundwork for all these structural changes is being done by a committee of ten deputy ministers. One member of this powerful group, called the DM-10 committee, is Thomas Eberlee, deputy minister of labor. Eberlee says the new structure will essentially be a "tripartite" forum comprised of government, organized labor, and business. "We will soon see new relationships emerging among these groups," Eberlee predicts. Among Canadian bureaucrats, the word "tripartite" is heard almost as often as "third option" these days.

### HERE COMES CANADA INC.

While the organizational details of tripartitism still remain to be completed and announced—at first blush, the idea sounds like a cross between West Germany's *Mitbestimmung* and the Soviet Union's GOSPLAN—it is easy to see how such a system would vastly expand the federal government's powers to plan and coordinate Canada's economic growth. Neither private companies nor provincial governments would be able to run their affairs without Ottawa's approval. By controlling access to the capital markets, for example, the federal government could reward some companies, punish others, and force construction of new plants wherever the authorities want them built. And so long as the controls program remains in effect (it expires December 31, 1978, and Trudeau says that only a "miracle" would induce him to end it sooner) the government can force adjustments in wages and profits whenever it likes.

Tripartitism is the culmination of Trudeau's drive to increase the power of the Federal Government. That dovetails neatly with his effort to loosen ties to the United States, because the third option's objectives cannot be accomplished until Ottawa gets the authority to guide and direct the country's economy. Tripartitism is a way to knit a weak, loosely connected group of provinces and private enterprises into a coherent, rational, manageable organization—a sort of Canada Inc., with the prime minister as chairman of the board.

The third option has been opposed from the start by some provincial goverments. Quebec, for example, wants tighter economic links to the United States in hopes of attracting investment that would create jobs. "We are among the poorest provinces in Canada," explains Robert Bourassa, Quebec's intense, French-speaking premier. "We want foreign investment here. We need the jobs such investments will bring." Bourassa regularly visits the United States. "You are welcome here," he says, over and over again. "Please, come and build plants in Quebec."

Alberta, which produces 85 percent of Canada's oil, also wants closer ties with the United States. The province currently produces 1.2 million barrels a day, and its ultimately recoverable reserves have been estimated at 262 billion barrels (including vast quantities in expensive-to-process tar sands). That's more than the proven reserves of Saudi Arabia, and the province seeks American investment so that it can get its oil out of the ground while prices are high. In the booming oil towns of Calgary and Edmonton, Pierre Trudeau's third option is viewed as a dirty trick to keep Albertans from getting rich.

The opposition of provincial governments to the third option has been a serious problem for Trudeau, because the provinces have been able to set their own courses independently of Ottawa's direction. The source of their power is a document written in another country, in another century. The British North America Act of 1867 established the federal-provincial relationship in Canada. In composing the document, the British parliament gave most powers to the provincial governments, leaving Ottawa in a relatively weak position.

### THE PROVINCES ARE TIGHTFISTED

The 1867 act, which stands today as Canada's constitution, contained a time bomb that exploded at precisely that moment when Trudeau launched his third option. All mineral resources are owned by the provincial governments. That ownership was not a great source of power before 1972. But when the age of shortages arrived, and with it skyrocketing prices for virtually anything that came from the ground, some of Canada's provinces found themselves on the threshold of extraordinary wealth. They were not inclined to be generous about sharing the wealth with Ottawa or the other provinces.

In setting out to take over the eleven potash mines that are operating within its borders, the government of Saskatchewan, a midwest farming procince, aims to get control over deposits representing 40 percent of the world's potash reserves. Last year the mines, mostly American owned, poured $100 million of royalties and taxes into Saskatchewan's coffers. But the Trudeau government opposed the takeover, though the result would be a broken link with the U.S. Ottawa argued that the profits should go to the federal government to redistribute as it saw fit. Saskatchewan, in effect, told Ottawa to buzz off, and is going ahead with the takeover.

A similar battle for mineral-ersource wealth developed between the Trudeau government and the Pacific northwest province of British Columbia. As prices zoomed for British Columbia's copper and zinc, the provincial government in Victoria boosted mining taxes and royalties to the point where Ottawa, once again, felt it was being cut out of the money. Trudeau responded by raising the federal mining tax rates and by declaring that provincial taxes and royalties would no longer be deductible. As a result of this particular struggle for revenue, the effective tax rate for some mining companies in Briitish Columbia exceeded 100 percent. In 1975, Gibraltar Mines Ltd., a Vancouver-based affiliate of Noranda Mines, earned $1,633,000; its taxes that year totaled $2,009,000.

Ottawa's most potent weapon in its struggle with the provinces for control over mineral resources is the Canada Development Corporation. This government company was established in 1971 to invest in Canadian-controlled corporations and give them a chance to grow. But C.D.C.'s mission soon widened. In July, 1973, it made a tender offer for 30 percent of the shares of Texasgulf Inc., the giant U.S. mining company with extensive Canadian properties. The buy-back stunned the U.S. and Canadian business communities, and cost Canadian taxpayers $271 million. It effectively transferred control of the American company to the Canadian government.

Last year came the formation of Petro-Canada, a government-owned oil company whose purpose, the prime minister said, was to provide Ottawa with a "window" into the country's foreign-controlled energy industry. But Petro-Can soon abandoned that modest pretense and began to expand rapidly into a major oil company with multinational connections. Its chairman, Maurice F. Strong, a highly successful oilman, has already held preliminary discussions on deals with Venezuela and North Vietnam. "We now have an international mandate," Strong insists.

Petro-Can started off with $500 million in equity and the right to borrow $1 billion more over the next five years with government backing. Regulations announced in May by the ministry of energy, mines, and resources give the company some roaring advantages over private companies. For example, it now has the right to explore any open federal acreage, and also has first choice of any allocated federal acreage that isn't developed by private companies during the next seven years.

Another new rule requires that all new exploration ventures on federal acreage be at least 25 percent Canadian-owned. Since Petro-Can is the only big Canadian-owned oil company in the country, the rule will force private companies to take on the government as a partner. And in a further extension of its power, Petro-Can announced plans in June to buy the Canadian subsidiary of Atlantic Richfield for $335 million.

### IT'S NOT THE PRINCIPLE

Like the provincial governments, the Canadian business community has consistently opposed Trudeau's third-option policy. Most Canadian businessmen have been more concerned with the health of their country's economy than with the nationality of its owners. And at just about the same time that Trudeau launched the third option, the Canadian economy was beginning to weaken. As Paul H. Leman, the president of Alcar Aluminium, puts it: "We caught a bad case of the English sickness." Wage rates, for example went up so high, so fast, that by 1975, Northern Telecom Ltd., a subsidiary of Bell Canada, was paying $1.85 per hour more to its Canadian workers than to its U.S. employees. In the paper and pulp industry, wages in Canada rose to nearly $1 per hour more than in the U.S.

Canadian businessmen are reacting by doing exactly the reverse of what the Trudeau government wants them to do. They are allowing market forces rather than political considerations to guide them, and those forces lead them to tighten the U.S.-Canadian connection Ottawa is so anxious to break. "We've done a magnificent job of making ourselves uncompetitive internationally" is the very bitter conclusion of Robert C. Scrivener, chairman of Northern Telecom. "Canadians are now being paid more to work less efficiently than their counterparts in the U.S. Our competitive position has eroded to the point where we're seeing the ultimate irony: Canadian companies starting up plants in the U.S. so they may compete in the Canadian market."

Last year Dominion Textile Ltd., a Montreal-based company with annual sales of $273 million, bought a U.S. textile company called DHJ Industries Inc. that operates ten plants in the States. Domtex says its operating costs for these plants are 15 to 20 percent lower than for its similar plants in Canada. The company has warned shareholders that "as our plants reach obsolescence they are not being replaced here in Canada."

Some Noranda Mines affiliates have slashed their budgets for mineral exploration in Canada by as much as 50 percent, and put the money into U.S. exploration projects. Dominion Bridge Co., a Montreal structural-steel manufacturer, is also weakening its ties to Canada—its principal officers are now based in New Hampshire, and the company is expanding in the U.S. "Canada was pricing itself out of the world markets and we weren't prepared to sit there and see this happen," explains Kenneth S. Barclay, the company's president.

### FIRA SHOWS ITS COLORS

Today, in a reversal that could mean big trouble for Canada's future development, the flow of investment capital from Canada to the U.S. exceeds the northward flow. This outflow of badly needed capital is likely to increase still further as a result of some recent decisions by the Foreign Investment Review Agency, which was established by Trudeau back in 1974 and which is now beginning to show its colors.

The enabling legislation requires foreign-owned companies to obtain FIRA's approval before starting a new company in Canada, buying a Canadian company, or expanding into a new line of business. Only if FIRA deems the project to be "of significant benefit to Canada" is the application approved. But now FIRA is using this vague, very broad authority to force U.S. companies into selling their Canadian subsidiaries back to Canadians.

When Gulf & Western Industries acquired the U.S. publishing firm of Simon & Schuster in June, 1975, FIRA ruled that the publishing firm's Canadian subsidiary, Simon & Schuster of Canada Ltd., could not be transferred to the new owners. Gulf & Western had to sell off the subsidiary to a Canadian buyer.

FIRA's actions, combined with Ottawa's other policies and the Saskatchewan potash takeover, have led American businessmen with interests in Canada to start asking, "What's the political risk factor up there?" Some have already decided that it's too high. Robert E. Naegele, president of Dow Chemical of Canada, says his company is seriously thinking of abandoning plans to build a petrochemical plant in Alberta.

### LABOR'S ROUTE TO POWER

Trudeau's term of office ends in 1978, and he must call an election sometime before then. But even if he were thrown out of office, his successor would find it difficult to reverse the present policies. Both government control of the economy and nationalism remain extremely popular with Canadian voters. A public-opinion survey published in May showed that a majority considers U.S. economic and cultural influence to be a "major source of concern." The new leader of the opposition Conservative party, thirty-seven-year-old Joe Clark, concedes that even if he came to power, "we'd be more inclined to slow things down, rather than reverse them."

As Trudeau pushes ahead with his plans to reshape the Canadian economy, he is welcoming a new, potentially very powerful ally: Canada's labor movement. Its guiding organization is the Canadian Labor Congress, a fast-growing coalition of militant unions that now represents 36 percent of the country's work force.

Previously no friend of Trudeau, the C.L.C. believes that the policy of tripartitism will give labor a much larger role than it now has in planning and managing the country's economy. Ronald Lang, forty-three, C.L.C.'s director of legislation, says the organization views tripartitism as its route to power in "all economic affairs" of Canada. "Quite frankly," says Laug, who quit high school at sixteen, started again at thirty-one, and kept on going until he earned a Ph.D. from the London School of Economics, "what we're doing now is organizing ourselves so that when tripartitism comes, labor has got the strongest voice at the table."

Events are moving swiftly now, and deep and lasting change in Canada is inevitable as Trudeau pursues his policies. In June, he held the first of a series of meetings with C.L.C. leaders to discuss tripartitism. In July, he announced the establishment of a "contractual link" between Canada and the Common Market that he says will pave the way for Canadian businesses to get additional non-American trading partners. The prime minister has been so deeply immersed in projects to push Canada away from the U.S. and to centralize economic power, in fact, that he seems to give scant thought these days to what Canada will be like if his efforts prove successful.

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