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Senate

SENATORS
JOHN HUBER, CH.
JOE ORSINI
PAT RODEY

April 2, 1976

Attached for your perusal is a report on methanol provided to me by Senator Tillion. In my opinion, this is one of the best works on methanol to date, and I urge you to study it.

John Huber

John Huber

Draft of 10/75
uncorrected

THE INTRODUCTION OF METHANOL AS A NEW FUEL INTO THE U. S. ECONOMY

William J. Barr

Frank A. Parker

For

The Foundation for Ocean Research
La Jolla, California

Corrected, augmented version
will be out from printers by 4/76
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7655 Old Springhouse Road
Westgate Research Park
McLean, Virginia 22101

Supported and printed by Southern California First National Bank

AGO 513372

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Tillion

INTRODUCTION

No single problem will have a greater effect on the form and structure of America than the manner in which the nation copes with management of our energy resources.

The very existence of our free enterprise system, as we know it, will depend on prompt, strong, national decisions in the field of energy.

We firmly believe that there is a great danger in looking for simple and utopian solutions to problems of such complexity.

It is our strong feeling that solutions which appear to have a high probability of mitigating some of the economic and social consequences of this present dilemma in the field of energy should be supported both by government and the private sector.

Initially, we felt that arguments toward development of a methanol-based energy economy were quite fascinating. That's why we supported this report in order to present in one compendium arguments summarizing present knowledge in the field.

With the completion of this project, a review of this report has convinced us that methanol may in fact be the only fuel that can have any short-term impact in rearranging the economic and geopolitical forces in the energy field in the next decade.

We believe that methanol plants and distribution facilities can and should be started immediately through individual and governmental partnership and that a careful and thorough review of this report will lead unbiased and unprejudiced reviewers to the same conclusion.

We hope that in a small way Southern California First National Bank's support of this project may help to start national action.

Richard T. Silberman
President
Southern California First National Bank

FORWARD

This document and associated activity was stimulated in its preparation by earlier considerations developed by Jeffery Frautschy, a trustee of the Foundation for Ocean Research, and myself. Examination of the development of the National Research and Development energy program indicated to us certain curious anomalies. The principal one is the heavy emphasis by industry and government in money and previously expended research effort on far out technology and the low emphasis on largely established but currently unemployed technologies.

The hard fact seems to be that the problems of introduction of new energy sources on a large scale are more formidable than the technological problems. Therefore commitment to an energy solution, which requires large investment in research and development before facing the problems of introduction, is in effect a delaying action.

We must seek a fuel based on known domestic sources and on an existing acceptable level of technology. If R&D then can benefit efficiency of production and cost, it can proceed in parallel with solving the problems of introduction. Complete national dependence on new continuing R&D has no more place in a completely rational national energy program than does continued reliance on a diminishing finite world petroleum resource.

The starting point in our analysis of energy problems is the same as most other serious thinkers on the subject. It is based on:

1. The short time finite character of presently utilized sources of energy.

2. The desire to achieve independence from foreign sources of energy supplies.

3. The severe problems and mounting costs associated with the elimination of harmful local environmental effects.

4. The pervasive problem of maintaining global environmental stability: this is primarily the concern with the irreversible and continual injection of carbon dioxide into the environment by the use of fossil fuel.

There is an intense national debate on the energy problem with all its economic implications for many diverse interest groups and the environmental implications for many other groups. The two sets overlap to a considerable extent. The intensity of the debate obscures the four salient and fundamental points made above. This is most unfortunate and if it continues, it will be an effective block in meeting the national energy objectives.

Continuing delay in basing our essential energy requirements on sources other than petroleum will only exacerbate what already is a crisis situation.

In evaluating energy alternatives in the light of fundamental concerns expressed here, one and only one candidate fuel, methanol, qualifies for massive early introduction. Therefore this report is devoted primarily to consideration of methanol. It recognizes its historical values in energy applications, the technical feasibility of its production and use, and it proposes solutions to the infrastructure problem. This fuel is adequate for all power needs and can be used in automotive applications as well as for stationary sources. Other than a specific proposal for its massive introduction there is little that is original in this document. Because we believe that methanol has proved itself, our purpose is to bring together in one document what is known and to urge national direction and commitment to a priority program of methanol production and use.

William A. Nierenberg

President
Foundation for Ocean Research

ABSTRACT

The use of methanol as an alternative to distillate fuel oil for public utility combustion turbines provides an immediate opportunity to extend the U.S. supplies of petroleum. The existing requirements as well as the rapidly developing needs for increased peak and intermediate electric generating capacity by virtue of delays in conventional and nuclear power plant construction are accelerating the demand for clean liquid fuels. Available data and information indicate that relative to raw materials resources, operating performance, production technology, and economics the prospective use of methanol is also most encouraging to meet the future demands of the automotive fuel market in addition to the ready market of the electric utilities. Methanol can be produced by well-known technologies from natural gas, oil well flare gas, coal, or cellulose all of which are indigenous to the U.S. economy. In view of the major advantages to be had through introducing a much needed fuel obtained from abundant domestic materials, it is vital that means are explored for actively initiating and stimulating the necessary large scale field demonstration programs to accomplish this goal.

OVERVIEW

The current energy situation in the U.S. has focused attention on the diminishing availability of our petroleum and natural gas resources and the ultimate finite limitations of these materials as well as many others as sources of energy in this country. For years the continued successful discovery of major oil and gas deposits in the U. S. were principally responsible for a high rate of industrial development in the U.S. through the availability of low cost fuels. Coal was eventually displaced, except for public utility and coke production owing to cost as well as the fluid characteristics of oil and natural gas which are more favorable for commercial application. Towards the end of the 1930's when fewer giant oil fields were being discovered in the U.S. huge quantities of low cost petroleum became available from Canada, Venezuela and the Middle East. At the end of World War II the plentiful Middle East petroleum resulted in continued flow of low cost crude to the U.S. Industrial development both here and abroad expanded greatly through 25 years of productive post war economy.

More recently the attitude of the producing countries has changed to one of active control of the flow of crude from their wells to the consuming nations. This altered outlook coupled with a reduced rate of oil discovery and production in the U.S. and increasing costs of foreign oil has highlighted the nation's critical energy situation. By virtue of the continued rate of energy consumption, the country has re-examined the energy alternatives open and the options that can be realistically considered for the present, the foreseeable future, and the far-distant future.

The 1973 known U.S. recoverable reserves* of petroleum consist of 48 billion barrels (2 trillion gallons) and include the so-called proved reserves plus the reserve economically recoverable by established secondary-recovery methods. In addition there are the statistically projected undiscovered recoverable resources, known marginal and submarginal resources not economically recoverable at present, and undiscovered marginal and submarginal resources not economically recoverable at present.[58, 69, 70]

Supplementing the above, there are also natural gas liquids derived from natural gas the reserves of which are generally in proportion to those of natural gas. These natural gas liquids plus crude oil constitute the so-called petroleum liquids. Table I is a tabulation of both of these liquid energy resources in the U.S.[58, 69, 70]

Natural gas for many years has been an inexpensive fuel source owing to an artificially low well-head price maintained by the federal government through the 1938 Natural Gas Act for purposes of stimulating its use. Current demand approaching 25 trillion cubic feet annually is now approximately 10% of all known domestic reserves. As a consequence, curtailment is now a way of life with the natural gas distribution companies. Total proved reserves of U.S. natural gas in 1967 reached a high of 293 trillion cubic feet and reserves since then have declined each year except in 1970 when the Alaskan North Slope fields were brought into inventory. Proved reserves amounted to 250 trillion cubic feet at the end of 1973. In order to maintain the nation's current production level it would be necessary to add new reserves of approximately 22.5 trillion cubic feet annually. This is almost an impossible

* See Appendix I

TOTAL U.S. PETROLEUM RESOURCES

Known recoverable reserves 48 billion bbls.	Undiscovered recoverable resources 200 billion bbls.
Known marginal and sub marginal resources 40 billion bbls.	Undiscovered marginal and sub marginal resources 300 billion bbls.

TOTAL U.S. NATURAL GAS LIQUIDS RESOURCES

Known recoverable reserves 7 billion bbls.	Undiscovered recoverable resources 30 billion bbls.
Known marginal and sub marginal resources Not estimated	Undiscovered marginal and sub marginal resources 60 billion bbls.

TABLE I

task since during the past 29 years the average annual additions to our reserves have only been 16 trillion cubic feet. (see Table II)

Coal, although abundant in the U.S., suffers from neglect as well as high cost in underground operations. Further, the current technology of mining does not lend itself to rapid expansion of production. Although reserves are huge and estimated by various activities to be sufficient for the far distant future at current consumption levels, because of a severe loss of market in recent years the industry has been unable to generate or attract sufficient capital to develop additional production capacity. In addition, approximately 80% of all coal deposits are too high in sulphur to meet today's environmental standards which necessitate either cleaning the coal or cleaning the products of combustion. Production today of approximately 600 million tons annually is about equally divided between underground and strip mining. The former employs approximately 110,000 miners each producing approximately 11 tons per day, with slight prospect of increasing production without adding to the work force.[70] This daily rate is down from 15 tons per day achieved in earlier years due to more stringent safety requirements.[70] Unfortunately the several years of planning, engineering and construction preparatory to opening a coal mine preclude any immediate rapid addition to the nation's supply above ground. Strip mining on the other hand with its 35,000 employees[70] provides the nation with a means of accelerating coal production without resorting to large increases in personnel. The average production per man per day averages 35 tons.[70] The technology is not without problems owing to the present limited production of the manufacturers of large drag lines and earth moving equipment.

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TOTAL U.S. NATURAL GAS RESOURCES[70]

Known recoverable reserves 250 trillion cu. ft.	Undiscovered recoverable resources 1100-2200 trillion cu. ft.
Known marginal and submarginal resources Not estimated	Undiscovered marginal and submarginal resources 850 trillion cu. ft.

TABLE II

TOTAL U.S. COAL RESOURCES

Known recoverable reserves 220 billion tons	Undiscovered recoverable resources Not estimated
Known marginal and submarginal resources 1,400 billion tons	Undiscovered marginal and submarginal resources 1,600 billion tons

TABLE III

TOTAL U.S. OIL SHALE RESOURCES

Known recoverable reserves 50 billion bbl.	Undiscovered recoverable resources Not estimated
Known marginal and submarginal resources 2,000 billion bbl.	Undiscovered marginal and submarginal resources 4,000 billion bbl.

TABLE IV

only a small fraction of these deposits are in the U.S. There has been renewed interest in Canadian deposits of these sands and recent exploitation has resulted in the successful development of a 50,000 barrel per day commercial oil plant in that country. The process economics are again a major deterrent to further expansion.[61, 124]

A number of other well-known large scale energy sources such as nuclear and solar will ultimately contribute importantly to our energy supply. Although fission will play a more and more significant role in generating electricity, environmental restrictions in siting and safety as well as waste disposal will continue to stretch out lead times until solved. Hopefully, on a far longer time scale, the nuclear breeder reactor will one day make nonfissionable material fissionable thus expanding the supply of nuclear fuels.

On an even greater time scale, beyond the year 2000, fusion with the aid of considerable long term research plus several major scientific "breakthroughs" could eventually begin to play a role.

A long range goal should be the utilization of solar energy on a very large scale. Other than for agricultural purposes and for lumber and paper, utilization of this vast source awaits a technological development that will make it an economic source of energy. The quantity of solar energy annually striking on the earth is greatly in excess of our requirements. Fortunately there are at hand means to capture the solar energy associated with the earth's vegetation. This body of material constitutes a vast reservoir of energy which is continually replenished. The carbon and hydrogen constituents provide the basis for an unlimited variety of chemical compounds whose energy is available to man.

Considerable quantities of heat are potentially available from the elevated temperatures of the earth's core.[70] At depths of from 10 to 20 miles the temperatures range from 200°C to 1000°C. Investigators calculate that the amount of this so-called geothermal energy is as much as 2000 times the heat available from the coal resources of the world. Unfortunately this energy is only of interest commercially where it has been localized near the earth's surface. The engineering problems in utilizing high temperature sources at 10 to 20 miles below the surface are extremely difficult. Notwithstanding, there have been commercially successful undertakings in California, in particular, to use geothermal energy for electric power generation.

Paramount among the present and foreseeable options available to the nation is that of increased exploration and production of the energy source materials as well as conservation in the application. The latter is well known to consumers in the form of curtailment of energy-using activities. The former primarily revolves around seeking oil and gas under the oceans adjacent to our coasts by offshore drilling techniques, undertaking secondary and tertiary extraction of petroleum from existing fields, improving underground coal mining techniques to eliminate the approximately 50% of the deposit left behind after mining, and capturing the large quantity of gas presently being vented or flared from our petroleum fields, both onshore and offshore.

The geologically favorable areas in the U.S. for the occurrence of petroleum are as yet little explored. In continental U.S. and Alaska plus adjacent continental shelves there is about 1,860,000 square miles of such land. It has been estimated by the U.S. Geological Survey that less than

20% of this land has been explored for petroleum. The recent 1974 U.S.G.S. study estimates that offshore in the Atlantic, Pacific, Gulf of Mexico and Alaskan waters there remain 130 billion barrels of undiscovered recoverable resources.[70] For natural gas offshore, similar estimates by U.S.G.S. in 1974 are as high as 450 trillion cubic feet.[70]

As recently as 1973 we have vented and flared onshore 250 billion[116] cubic feet of gas annually which is equivalent to 50 million barrels of oil. On the outer continental shelf in the Gulf of Mexico estimates indicate we may be venting and flaring an additional 50 billion cubic feet annually.[44]

Additional programs are addressing the problem of utilizing agriculture and animal waste, municipal trash,[68] refuse and sludge, and forest products waste. All essentially are concerned with converting organic materials by heat to a synthetic gaseous, liquid, or solid fuel.[18, 19, 21, 29]

There is not a shortage of energy in the U.S. but rather a shortage of technical capability and engineering technology to promptly and economically convert on a commercial scale the existing energy to a form useful in our society. The aforementioned cheap crude and natural gas provided little in the way of incentive to carry out the engineering and construction of large scale plants to convert coal to gaseous or liquid fuels or the design and development of chemical systems and plants for sourcing fuels from municipal waste. Most processes[19] in these areas have been well demonstrated in the laboratory; essentially none have even been scaled to a size capable of daily production of thousands of tons of products.

Following World War II owing to the existence of plentiful quantities of all solid, liquid, and gaseous fuels in the form of coal, petroleum, and natural gas, the business decision to exploit energy in the form of liquids and gases was quite clear. The post-war construction of addition networks of gas pipelines stimulated the transmission and utilization of natural gas in all parts of the country as contrasted to earlier years when the principal consumers were located near producing fields.

With the reduction of interest in coal for other than electric power, metallurgical purposes, and heat, little commercial effort was expended on applications other than at a few isolated institutions. Investigators had in earlier years examined the characteristics of the coal and had recognized it as a source of organic chemicals of almost unlimited variety. Many of these chemicals could be used as fuels as they were primarily carbon and hydrogen compounds. Among the early fuels produced was methanol (methyl alcohol) which in the 19th century had been derived primarily from wood. This material, which became one of the basic chemicals of the industry, was also recognized as an efficient clean burning liquid fuel. However its use as a fuel did not become widespread in modern times as coal was less expensive as was also manufactured gas from coal. With the advent of petroleum in the last century, there came into being a high energy liquid fuel which was less expensive than methanol and relatively clean burning. With competition from oil as well as from the growing natural gas business which soon displaced manufactured gas, methanol's acceptance as a fuel was limited. However, as a basic chemical for the chemical industry its growth continued rapidly. After it was demonstrated in the middle of the last century that it could be produced from methane, or synthesized from carbon monoxide and hydrogen, selecting inexpensive natural gas as feedstock for the process was the logical choice. The technology of producing methanol from coal although technically satisfactory was not competitive with low cost natural gas.

Present conditions reflecting the shortage of natural gas as a feedstock for methanol are leading to coal again as a source raw material. Concurrently shortages of petroleum point to an immediate need for synthetic fuels to replace or supplement distillate and gasoline. Methanol is again the leading candidate to serve as an alternative fuel to distillate and gasoline. This high energy, clean burning fuel which is now produced by the U.S. chemical industry in quantities exceeding a billion gallons[11] annually is available today to meet limited demands of the automotive market to demonstrate its application as an additive to gasoline, and, also to show its practical application to the public utility combustion turbine as a substitute fuel to distillate for peak electric power generation.

ENERGY POLICY

Although scientists and engineers have been predicting a major shortage of petroleum products before the end of the century and although there have been groups of experts, Presidential panels, and high-level committees that have studied all aspects of the energy problem little has been done but talk. All have concluded that the increased demand coupled with the reduced supply of U.S. oil have made it necessary to rely more heavily on increased imports. For a number of years the foreign oil was available to the U.S. at an attractively low price so that the cost of energy derived from petroleum did not change appreciably. However, as our demand increased for foreign oil, the oil producing countries (OPEC) began to feel that they were being treated inequitably. This attitude coupled with the Israeli/Arab conflict and the strong U.S. support of Israel, culminated in the 1973 oil embargo by the Arab countries and a doubling in the price of oil. This created an immediate crisis which quickly resulted in the shortage of gasoline as the lines formed at filling stations. The time had come to act decisively.

The first emergency action in response to the embargo was the formation of the Federal Energy Office (FEO) by President Nixon late in 1973. This office has concerned itself principally with the conservation of supplies and their equitable distribution, the promotion of usable energy resources, defacto price controls, and the development of plans to meet the energy needs of the nation. This office was assembled on a crash basis and was staffed principally by people on loan from other federal agencies; in addition, however, the Administration found it necessary to call heavily on the petroleum industry to furnish it with people who were expert about petroleum problems and the petroleum business.

On May 7, 1974, the Congress converted the Federal Energy Office into the Federal Energy Administration, with essentially the same charter. However, the termination date of this agency is June 30, 1976, at which time unless extended it will cease to exist. Also, dealing with the energy matters, the Congress created the Energy Research and Development Agency (ERDA) on October 11, 1974, to bring together in one place within the government the various federal activities dealing with energy research and development matters. This included the Atomic Energy Commission, the Department of Interior, the National Science Foundation, and other energy research groups elsewhere in the government.

Finally the Congress passed on December 31, 1974, the "Federal Non-Nuclear Energy Research and Development Act of 1974." Its basic purpose is to develop on an urgent or "crash" basis the technological capability to support the broad range of energy policy options through conservation and the use of domestic energy resources. This Energy Research and Development Agency was further instructed by the Congress to conduct large demonstrations of practical manufacturing processes of potentially useful energy sources and the development of the necessary technologies. ERDA was directed to proceed on a crash basis with these programs making commitments similar in magnitude, scope, and urgency to those undertaken in the Manhattan project and the Apollo program. Also, the President created the Federal Energy Council under the chairmanship of the Secretary of Interior to develop hard Administration and congressional policies on all aspects of the energy program in the various parts of the government.

1974 saw the creation of these administrative bodies in the government to cope with the energy crisis, however, there has been little progress in the development of firm government policies that have come from any of these groups. The first important action was the creation of Project Independence under FEO. The objective of this project was to develop means whereby the U.S. would be free of dependence on foreign petroleum resources by 1985. It has never been given more than token recognition. Towards the end of the Nixon Administration, energy policy immediately became the victim of infighting between Treasury and State and other governmental departments and the Congress. After much discussion of the objectives of Project Independence, there emerged a new policy of "interdependence" whereby the principal oil consuming nations of the world would act in concert on important energy issues. However, there have been contradictions to this concept, such as the imposition of import levies and a conflicting suggestion that the government put a "floor" price on foreign oil to protect the investments of the U.S. oil companies and encourage further exploration. As a consequence it has never gained wide acceptance abroad.

There are still no firm policies with respect to the development and conservation of petroleum produced energy, with much confusion among all federal agencies concerning energy matters. There does, however, appear to be one issue that transcends the political and administrative problems: there is unanimity with the objective of being independent of foreign sources of energy just as soon as possible. Looking at the various alternatives, this full freedom could be achieved by 1990 to 2000 but will require a major national effort and a huge capital investment over that period. To accomplish this at all and certainly by the latter part of this century, the government is going to have to make hard decisions now with respect to the policies and paths it elects to follow and what products to concentrate on.

The government has a program directed toward the development of synthetic fuels, which, while not large, is looking at a wide variety of possible options. If anything, the government seems to be shot-gunning their research and development by simultaneously looking at many technical alternatives for products and processes rather than narrowing down the options to a few and spending the requisite resources on the most promising. Even with these decisions and a narrowing of options each of the most likely processes will involve major capital outlays necessary to carry it through the demonstration phase.

A particularly important option is to make a long term policy commitment to methanol as a principal synthetic fuel for gasoline blends for automotive fuels and for a replacement to distillate for electrical gas turbines. The synthesis of methanol using coal as a feedstock has been done commercially. It is clearly the best and most acceptable liquid synthetic fuel and is the only fuel that can be introduced into the economy in sufficient quantities in the next 10 to 15 years. It is the opinion that with the necessary level of effort, methanol can be produced in sufficient quantities from coal by 1985-1990 which would virtually eliminate the U.S. dependence on foreign petroleum. This dependence can be achieved for a capital investment of

$20 billion for plant and equipment, expended over the next 15 years. Using coal as a feedstock it is anticipated that it will be priced at an acceptable cost.

To construct a single large plant will require an investment of about $500 million. This sort of investment, however, with an uncertain market, is so large that guarantees will have to be made in order to raise the requisite capital. The guarantees are sufficiently large that it is anticipated the government may have to guarantee these investments. In addition, because of the ever present danger of price competition where the Arab countries deliberately decrease the price of their crude to a point that forces the synthetics off of the market; it is anticipated that some price protection must be given as well. This protection can only come from actions taken by the government.

In summary, after reaching a policy decision on the methanol option several decisive steps must be taken. Several processes must be selected for major demonstration and exploitation, national priorities must be given for the early completion of the developments, and they must be directed to proceed on a high priority basis similar to the Apollo program or the Manhattan project. The government must develop the means to obtain the capital that will be required. Finally, the position of the government with respect to price protection will have to be formulated in such a way to make the decision to proceed financially acceptable to private investment.

CRITERIA FOR A NEW FUEL IN THE U.S. ECONOMY

The emphasis today on examining all the implications of introducing a new fuel into our economy necessitates establishing standards and guidelines which will not only serve to meet technical, economic, and performance criteria but also the constraints imposed by environmental, social, and political considerations. We are no longer simply faced with problems of measuring performance of an internal combustion engine operating on a new blend of gasoline; a gas turbine running on a modified light distillate; or an industrial burner utilizing a residual fuel. Other factors are weighed in the evaluation and requirements must be met. Answers must be found to such questions as:

1. From what materials will the fuel be sourced?
2. What other needs in our economy are met by products sourced from the same materials?
3. Is the process for producing the fuels a part of a proven technology?
4. Is the availability of skilled manpower sufficient to meet the manning requirements for production without causing severe dislocations in our industrial society?
5. Are the materials such as water available in the quantities needed for this process and at the time and at the location involved?
6. Can the new fuel take advantage of the existing distribution and marketing system for petroleum fuels?

7. Can the fuel be used in conjunction with petroleum or is complete replacement required?

8. Will the fuel satisfy the needs of existing power plants as well as the anticipated requirements of engines under development?

9. Can the fuels be sourced from abundant materials located in a politically stable environment?

10. Are the raw material resources compatible with long term forecasts of demand for the fuel?

11. Are the investments needed and the costs of producing the fuel to a reasonable standard of quality currently competitive with those of petroleum fuels and are they in a comparable range for the future with those projected for petroleum fuels?

12. Are the waste disposal and reclamation aspects of producing the fuel such that they can be solved within the required level of financial investment return?

13. Is the source of fuel material of a nature that regulatory commissions, existing legislation, and leasing policies will require licenses, permits, and concessions to extract the material?

14. Is the cost of producing this fuel sensitive to inherently difficult-to-predict factors relating to such matters as strip mining legislation and actions of conservation commissions?

15. Can an acceptable environmental impact study be prepared?

16. Are the lead times for the total system, i. e., from applying for a permit to extracting raw materials to introducing the fuel to the market, of the order of a few years, or 5 to 10 years, or 10 to 20 years?

17. Are the storage, transportation, and handling characteristics amendable to conventional methods?

18. Have extensive field tests been conducted with this fuel under actual operating conditions and for a sustained period of time sufficient to provide reliable test data?

19. Have extensive laboratory investigations been conducted on its compatibility with various materials and the hazards and toxicity of this fuel both in production as well as in application?

20. Are the products of combustion within the environmental standards set for oxides of nitrogen, carbon monoxide, and aldehydes?

21. Will an on-going research and development program be required to fill numerous and essential information gaps?

The emergence of methanol as an alternative liquid fuel in our economy is well supported by the favorable answers to the above questions. Not only is this fuel capable of meeting the criteria established by these questions but it has the added benefit of being available now. Although not plentiful in terms of the quantities that will eventually be required, the 1 billion gallons of methanol produced annually makes it one of the 15 largest volume chemicals produced in the U. S.[125]

SCENARIOS

Clearly the development, production, introduction, and acceptance of methanol or a synthetic fuel in our economy must be examined against particular time frames. As was noted earlier, many developments underway show encouraging possibilities for various synthetic fuels and sources of energy over an extended period of time. However to establish some perspective for viewing methanol in our economy, three time frames have been selected: 1975-1980, 1980-1990, and 1990 and beyond. These periods are selected to focus on the immediate action that will be called for to introduce substitutes for petroleum-derived fuels; the on-going energy developments which will materialize after five years; and the long range opportunities and developments which are estimated to require at least fifteen years and probably considerably more to reach fruition.

The nation's need for an immediate alternative clean fuel to gasoline and distillate is as much dictated by political considerations as by decreased availability of energy to meet our current demand. Such an alternative need not be a total replacement for gasoline or distillate. The merits of using a fuel that can be blended with conventional petroleum fuels is in itself a powerful tool for extending our current oil supplies. In addition, blends will permit taking advantage of existing petroleum distribution and marketing systems particularly relative to automotive use.

Although any synthetic fuel is likely to differ in cost from that of gasoline or distillate, the crucial consideration is the current differential in cost which is the price we are paying to enlarge our fuel supplies. Beyond that we must look at the cost projected for the petroleum fuels compared to estimated costs for a much needed new fuel which will serve to supplement our existing supplies. It is quite evident that the easily-found, low-cost oil and gas deposits have already been discovered. Future costs of locating and producing oil will escalate considerably and these reserves will clearly not be available in the 1975-1980 time frame.

Many of the well known sources of petroleum such as shale, tar sands, and coal, although excellent sources of oil over the next few decades, are not a part of the 1975-1980 scenario. As mining techniques of shale are perfected, as extraction methods and non-conventional oil sands technology is further developed, and as coal gasification processes come on stream, these increased energy deposits will be converted into petroleum-like or synthetic fuels. Meanwhile efforts must be accelerated to introduce those existing fuels which are available today by known technologies from our various sources of energy.

Exploratory studies have shown there is in the future potential for such processes as enzymatic hydrolysis of cellulose waste to glucose and then a conversion to ethanol fuel. At present this process is in the laboratory and will require a number of years to be commercialized.[130] Other studies are focused on processes for liquifying coal but are still years removed from commercial plants and the introduction of this liquid fuel into our economy.

In the 1980-1990 period there should begin to appear a variety of processes to produce technically acceptable synthetic solid, liquid, and gaseous fuels some of which may be attractive commercially. Synthetic coke developments are progressing; coal gasification and coal liquification research is a part of many petroleum and coal companies' programs; the nuclear breeder reactor potential should begin to materialize; and the pyrolysis processes for converting municipal, agricultural, and forest products waste to liquid synthetic fuels should result in many plants operating on a commercial scale.[53, 54, 55] Notwithstanding the growing shortage of petroleum and natural gas, continuous discoveries coupled with imports of liquified natural gas will tend to offset a part of the reduction. It will, however, be quite clear as we progress into this time period that the availability of petroleum and natural gas as we know them today will be markedly curtailed. Offshore and arctic drilling costs are almost an order of magnitude more expensive than on land. Further, the transportation costs become increasingly expensive as oil prospecting and discoveries become more successful in the remote areas. The Alaskan reserve which it is estimated will be supplying between 7% and 13% of the U.S. demand by 1985 will be pumping 2 million barrels per day through a $5.5 billion dollar pipeline. With 17 billion barrels of recoverable crude, this will be a capital investment cost of 32 cents per barrel to transport this oil from Prudhoe Bay to Valdez.

Advances in the mining of coal together with the opening of new mines in the 1980's will have increased annual production to over 1 billion tons. Increased mining of low sulfur coal will bring environmentally acceptable solid fuels into the market in greater amounts. Increased production of sulfur-containing coal can provide the needed feedstock for coal-to-methanol plants. By the middle of the decade it should be possible to have operating a minimum of 10 plants using a proven gasification technology to provide a synthetic gas for manufacturing methanol at a rate of 5000 tons per day (40,000 barrels/day) per plant. It has been estimated that a demonstration plant producing methanol from coal could be operating by 1978 if pursued on a high priority schedule.[1]

The 1980-1990 period will be one in which plant construction and operations will proceed following modifications as a result of knowledge gained in operations. Financial consideration will be the major factor since economies of scale will necessitate large costly plants for coal conversion to synthetic fuels. Plants for conversion of municipal waste,[76,77,78] trash, refuse, and sludge will be limited in size only by the availability of feedstock. This will be a period in which use of synthetics, petroleum, and natural gas fuels will proceed concurrently. The introduction of new fuels into the U.S. economy unless dictated by public law will be evolutionary and as such the social impact and the industrial readjustments involved will need be assessed as this will be a period in which the conventional petroleum industry as we know it today will have stabilized.

Beyond 1990 the full impact of the synthetic fuels will be felt in our economy as well as the trend toward an all-electric economy. Mass transportation although an important factor in the nation's operation is highly sensitive to the geographical environment and population distribution. The need for automotive transportation will continue. Electric energy for mass transportation and other industrial, commercial, and domestic application will develop slowly. Our use of gaseous fuels will be limited to those applications in which solids and liquids are unacceptable. Natural gas as such beyond 1990 will constitute a source of raw materials for chemicals rather than a fuel for energy.

Beyond 1990 research is expected to focus on electrical energy and its generation directly [illegible] nuclear fuels, low sulfur fuels, and hopefully, fusion. Appreciable progress will be made to eliminate energy wasting processes that dissipate heat in converting from one form of energy to another. A direct conversion to electricity would solve much of this problem. Concurrently the liquid fuel industry will be sourcing such fuels as methanol from high sulfur coal and from waste, trash, and refuse. The latter is directly correlated with population and industry activity. As population growth increases less rapidly and as industry becomes more conservation conscious, there will of course be less waste available. Consequently it is foreseen that many liquid fuels from these materials will reach a predictable maximum.

METHANOL AND METHANOL BLENDS

Methanol is a clear water-white liquid with an alcohol odor. It retains its liquid properties over a wide temperature range; freezing occurs at -100°F and boiling at atmospheric pressure at 149°F. Compared to 100 octane gasoline, methanol has a somewhat lower boiling point and freezing point, is a little more dense, and contains about 50% of the heating value. It readily absorbs water and also mixes with water in any ratio without phase separation. In the absence of water it will dissolve in many hydrocarbons. Specifically, methanol is completely miscible in an aromatic gasoline at room temperatures while its solubility in a gasoline, such as octane, is 3%. The stability of methanol-gasoline-water solutions decreases with lowering temperatures. (See Table V)

Such characteristics of methanol and methanol-gasoline blends as vapor pressure have been studied. The cold start problem of conventional automotive engines primarily relates only to the use of 100% methanol and can be corrected by carburetor modifications. The addition of more volatile hydrocarbons into the methanol are other solutions to this difficulty.[3,5,6,9] Methanol does not have the lubricity properties generally associated with petroleum derived fuels. Consequently in systems engineered to utilize self-lubricating methods, the use of methanol requires a lubricating additive or different pumps.

The problems associated with using 100% methanol as an engine fuel can be grouped essentially into four categories. With the possible exception of the fourth listed below, the problems are of an engineering nature and their solutions lie in engineering changes that can readily be

PROPERTIES OF METHANOL AND GASOLINE[1]

	Methanol	Gasoline
Spec. Gravity (°F)	.792	.74
Heating Value (High)	9,770 BTU/lb	21,000 BTU/lb
Air/Fuel Ratio (Stoich.)	6.45	15.3
Energy, Air/Fuel Mixture (Stoich.)	94.5 BTU/cu. ft.	95.5 BTU/cu. ft.
Heat of Vaporization	502 BTU/lb.	116 BTU/lb.
Octane Number (Research)	106	91
Octane Number (Motor)	92	84
Freezing Point	-144° F	-100° F
Boiling Point	149° F	100° F - 400° F

TABLE V

made.

1. Methanol has a low volatility compared to gasoline and will boil at 149° F. Consequently for engines equipped with carburetors some means of adding heat or increasing volatility is needed to start the engine at low temperatures. Fuel injection equipped engines and combustion turbines should not be effected by this characteristic.

2. Methanol's high heat of vaporization (502 BTU per lb.) dictates the need for additional heating devices or means to heat the manifold of the engine in order to provide satisfactory mixtures of vaporized fuel and air for ignition. This would not constitute a problem in a combustion turbine engine.

3. Owing to a heat of reaction (9,770 BTU per lb.) equal to only 50% of gasoline, capacities of auto fuel tanks and associated fuel equipment must be somewhat larger toaccomodate larger volumes of liquid.

4. Methanol appears to be incompatible with certain materials generally used in engine construction. The resulting chemical reactions may produce corrosion and objectionable deposits in the system.

The use of methanol-gasoline blends also presents a number of problems which are somewhat different in nature to those associated with use of 100 % methanol. These consist of:

1. Mixtures of liquid systems obey certain laws. If the mixtures

behave ideally, the vapor pressure of the mixture will be the sum of the partial pressures of each constituent. Furthermore the partial pressure of each constituent will be proportional to its mole fraction in the liquid mixture at all compositions. A liquid system that behaves in this manner is said to obey Raoult's Law.[126] A mixture of gasoline and methanol does not behave as an ideal liquid and does not obey Raoult's Law but shows a positive deviation. This deviation can amount to some 3 pounds per square inch above that expected by Raoult's Law for methanol quantities of 2 to 10% volume added to gasoline. This in itself is of no major concern except that the engineering of a conventional auto engine is designed for a vapor pressure (Reid Vapor Pressure) of about 10 psi at 100° F. with a prescribed blend of gasoline. An increase of 3 psi is estimated to produce enough pressure to cause vapor lock in the fuel system.[9] Either an engineering change in the engine fuel system or a chemical change in the fuel would be required to insure satisfactory operation. Figure 1 shows the influence on vapor pressure of methanol blended with gasoline[9] containing some aromatic components.

2. Methanol's solubility in gasoline and phase stability is dependent upon the composition of the gasoline as well as the water present and the temperature. Presumably the presence of aromatic and higher alcohols improves solubility according to published information.[1,9] Researchers in this area are not unanimous in agreeing[23]

EFFECT OF METHANOL ON GASOLINE VAPOR PRESSURE[9]

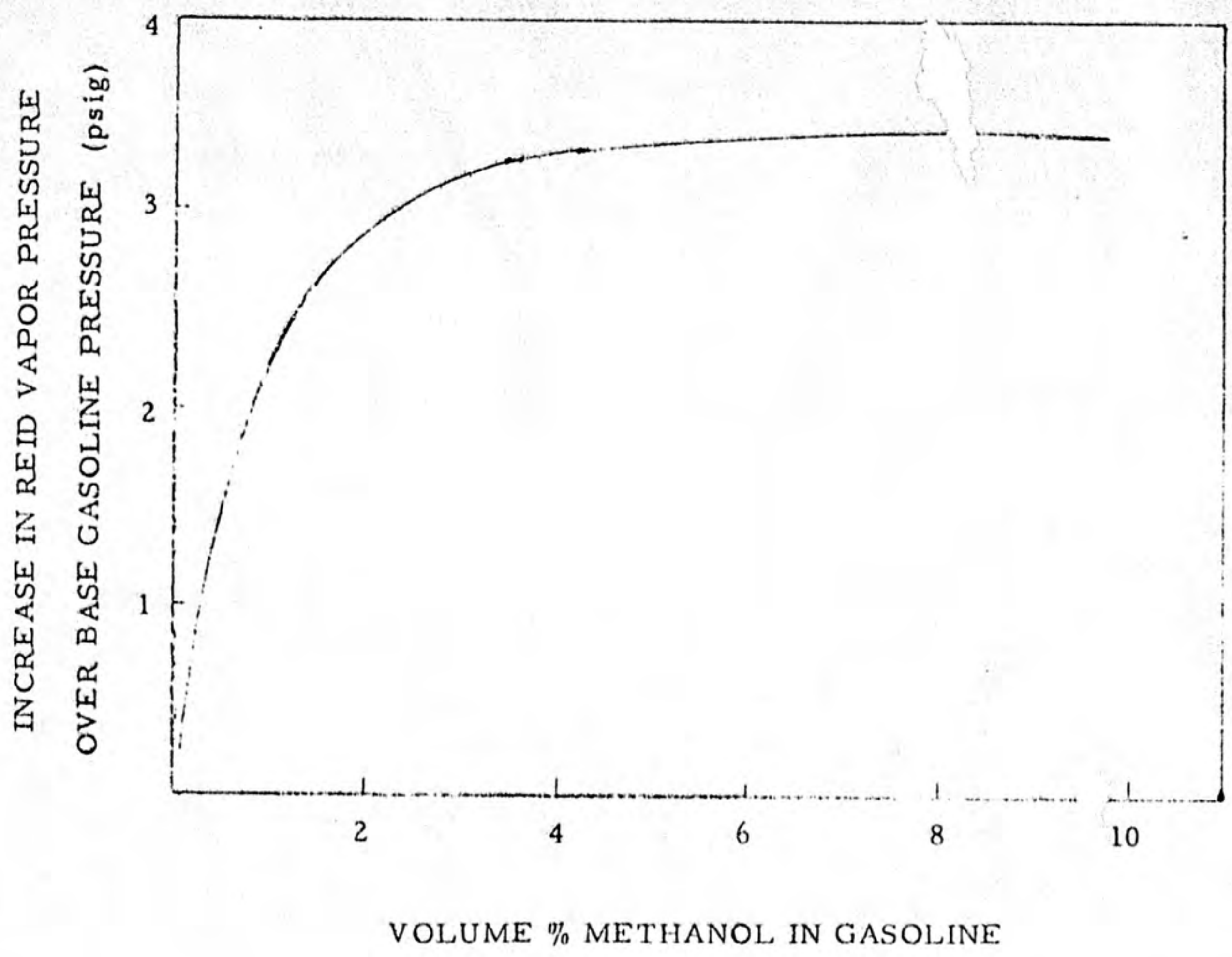


FIGURE 1

that this constitutes a major problem; furthermore should it prove to be of importance it is felt the solution is straightforward. Ultimately the widespread use of methanol - gasoline blends may necessitate better housekeeping in storage and distribution in order to minimize the presence of water.

A problem area common to both the use of 100% methanol as a fuel and blends of methanol and gasoline is that of exhaust emissions. Attempts have been made to analyze the performance of vehicles and engines fueled by both.[3,14,24,25,90,9] However there does not appear to be any major program focused on a precise comparison of performance and emissions in progress on a substantial number of vehicles which could provide statistically meaningful information. It is encouraging however that the test results reported by various organizations[9,90] show lower emissions of hydrocarbons, carbon monoxide, and oxides of nitrogen with methanol as compared to gasoline. On the other hand aldehyde emissions (formaldehyde) were higher than with gasoline.[90]

APPLICATIONS AND PERFORMANCE

Methanol and ethanol have been used as a substitute for gasoline several times in this century particularly during periods of war when[59] gasoline was in short supply. It has also been used successfully as a blend or supplement to gasoline in high performance engines. Owing to the recent shortages of gasoline and the questionable long term outlook for petroleum as a fuel, attention has recently been focused on methanol again as a possible alternative for automobiles. It can be produced at a competitive cost and can be stored and distributed as a liquid fuel in the same way as gasoline. Such companies as Volkswagen have examined using methanol both in carburetor and fuel injection pump engines and have converted a number of standard production vehicles to methanol operation.[90] Volkswagen has also tested[90] methanol in a stratified charge engine and obtained power output increases of up to 10%. A passenger car turbine developed in that organization has also been converted to methanol fuel with quite satisfactory results.

One of the main elements of today's electric power generating stations are oil fired combustion turbines for use in meeting peak load[1,4,65] demands. These units frequently have capacities as high as 25% of a public utility system's total capacity and although they may produce only 5% or 6% of the annual electric power output, yet account for 14% or 15% of the cost of fuel consumed. For the most part the public utilities are using No. 2 distillate fuel oil in combustion turbines. However, a wide range of fuels[108] including gas and methanol are compatible with this equipment. Total 1973 consumption of oil by these units in the United States approximated

280,000 barrels per day.[1,4] Studies by the Atomic Energy Commission indicated that this demand may reach 1 million barrels per day by 1980.[1] The use of methanol as an alternative fuel to oil in this application is clearly encouraging since the "low pollution" fuels for electric power generation such as natural gas, low sulfur coal, and low sulfur oil are in very limited supply. In the face of increasing demand they will continue to command a premium in the market place.

In addition to the peaking cycle application of combustion turbines, there are major technology changes occuring which will involve utilizing additional combustion turbine capacity. Public utility electric power generation can be patterned according to three types of loads: the base load which is the load met by continuously operating generators, the intermediate load which is served by power generating units running 12 to 14 hours per day for a five day week, and the peak loads which are met by units operating a few hours per day at the peak demand period. Prior to 1960 these loads have been met by conventional fossil fuel boilers and steam turbines. The newest equipment installed at the utility was used to meet the base load, older equipment was used intermittently for the intermediate load, and the oldest equipment would be used only a few hours per day at the peaks. During the 1960's the technology changed and the combustion turbines were installed for peak loads and supplemented with hydro and pumped storage systems as shown below. The new base load fossil fuel plants were designed in the 1960's for large capacities at very high operating pressures (600 megawatts and 3000 psi).[127]

Load	% Capacity (Kw)	% Load (Kwh)	Equipment
Base (24 hr/day)	53	64	Fossil fuel boilers and steam turbines.
Intermediate (12 to 14 hr/day)	27	30	Fossil fuel boilers and steam turbines.
Peak (1 to 3 hr/day)	20	6	Combustion turbines, hydro, pumped storage.

During the 1970's the technology again changed. Nuclear energy plants are now providing a part of the base load. High pressure fossil fuel generating capacity is also still being installed. Unfortunately it will be difficult to shift these units to intermediate load generation as they become older since the technical difficulties associated with running intermittently with supercritical fossil plants and nuclear plants are considered to be impractical owing to the severe thermal stresses produced by cyclical operation.

Consequently the intermediate load capacity will no longer be filled by older base load generating units but will have to be met by equipment specifically tailored to the part time service. One of the more promising systems to meet the intermediate load is a more efficient combustion turbine-steam turbine combination which involves the combustion turbine exhausting into a heat recovery steam turbine. Installations of this type system are expected to grow at the rate of 30% per year through 1985. The preferred fuel for these units is No. 2 distillate fuel oil with natural gas as an alternative. Among the immediate advantages is that the combustion turbine can be installed and put into service prior to the installation of the steam turbine.

The important characteristics of these combination units meet the principal requirements of any energy system needed to fulfill the intermediate (part-time) supply of power. They are:

Low cost of equipment per kilowatt of capacity
Rapid start-up and shut-down and flexibility of output
Availability and storage of required fuel.

As more installations are made there will be a coming need for large quantities of combustion turbine fuels for part-time service. Furthermore there will be a need for utilities to locate these intermediate load facilities at optimum sites in order to minimize costs of fuel sourcing and power distribution. In short, the current trend in public utility hardware is creating a large new market now and in the future for clean combustion turbine fuels. Hitherto natural gas or distillate fuel oil have been available in adequate amounts to meet the demand. It is now evident that these will no longer be available in sufficient quantities and that a clean fuel is needed which can be sourced from an abundant material at economically acceptable costs in a politically stable environment. Methanol can meet these needs.

The current performance of conventional gasoline and diesel fuels has been the result of a long series of development programs undertaken by the major petroleum companies of the world. Concurrently by improving the design of the internal combustion engine, fuels have been upgraded to provide selectively the desirable combustion and operating characteristics for improved performance in these engines. These characteristics primarily consist of such items as good inherent anti-knock characteristics to permit use of higher compression ratios, high volatility hydrocarbons to aid in starting and warm-up, additives to reduce corrosion in storage, reaction products which do not leave excessive deposits nor toxic emissions, and flame speeds and limits of flammability sufficiently wide to support a wide range of air-fuel ratios.

The performance characteristics of a fuel can be considerably altered through the use of additives or through blending a number of fuels to achieve enhanced performance. For example, it is well known that the use of aromatics or tetraethyl lead will improve the anti-knock or pre-ignition characteristics of gasoline. More recent work indicates that some rare-earth compounds will yield close to the same results in suppressing pre-ignition in gasoline-like fuels in internal combustion engines.[60]

Suitable means are also available for decreasing the heat of vaporization to improve ignition characteristics in starting internal combustion engines at low temperatures. Supplemental elements to pre-heat fuels as well as additives such as benzene have overcome the unusually high heat of vaporization in methanol.

Investigators have found that blends of gasoline, methanol, and water do not show good phase stability at low temperatures.[1,15,9] However, it appears that the presence of higher alcohols improves this situation as well as the presence of aromatics in the blend. Although the solution of the problem appears to be straightforward, an experimental program is necessary to establish the basis for formulating blends.

Experimental test programs have been conducted using as fuel a mixture primarily of methanol plus some higher alcohols[5,34] in a conventional public utility steam boiler electric generating plant. A 50 megawatt generator at New Orleans Public Service Inc. was operated for 2 weeks on an alcohol boiler fuel mixture. No environmental problems such as unburned hydrocarbons, sulfur oxides, or particulate emissions occurred. Furthermore the CO concentration and oxides of nitrogen were less than the emissions with natural gas or oil. Encouraging as these results are, the more appealing use for public utility application is in the combustion turbines now being employed by many power generation companies. With methanol as a fuel, lower turbine blade erosion and reduced deposit build-up is expected. The lower combustion flame temperature should provide reduced nitrogen oxide formation and indications are that substantial increases in running time of turbines between maintenance overhaul can be achieved.

The combustion turbine and automotive use of methanol require extensive field testing as published data indicates tests to date have been on a limited basis. To the extent that performance information is available, the results are highly encouraging in both applications. The conducting of large scale tests with many vehicles and drivers will provide excellent statistically meaningful information on the application of methanol as an alternative to gasoline for automotive use.

The General Electric Company combustion laboratories have run methanol fuel tests in the laboratory under simulated operating conditions and found that with appropriate valve, piping, and combustion chamber volume changes to reflect the lower energy per gallon of methanol the operating performance was good. Gas turbine operating experience with fuel oils has shown that basic corrosion and deposit problems exist in the turbine because of ash-forming substances that may be present in the oil. These problems are more severe with residuals and crude oils because they contain inherently larger quantities of the troublesome substances. It is not expected that these problems will develop with the use of methanol owing to its clean burning properties.

Of some concern, according to the General Electric combustion tests, is the lack of lubricating qualities in methanol which are inherent in fuel oils. A fuel pump for #2 distillate utilizes the lubricity of the fuel. Consequently the pumping of methanol would require supplemental lubrication or pumps designed for methanol.

It should be pointed out that contaminants in the inlet air or as salt water entrained in the fuel can also cause erosion, corrosion, and fouling of the turbine compressor.[110]

Considerable laboratory testing of engines, vehicles, and gas turbines has been performed by numerous investigators throughout the country. A number of universities[23] and research organizations have conducted laboratory scale and road tests with vehicles using blends of methanol and gasoline to ascertain the combustion performance as well as the characteristics of the emission products. Encouraging results have been obtained. It is however necessary to conduct large scale tests over a period of the order of a year with many vehicles and drivers to obtain statistically meaningful information. There are available in all municipalities fleet vehicles which are particularly appropriate for such an undertaking.

Police department cars, public utility cars, postal service autos, and city transportation vehicles such as buses, trucks, and motor pool fleets are typical of those groups which can be used for obtaining excellent data on performance, driver reactions, and life tests. Simultaneously these fleet tests can be used to secure data on the combustion emission products over an extended period of time under actual field conditions.

This field testing needs to be conducted concurrently with on-going laboratory tests as the optimization of engine performance relative to the selection of the most acceptable blend will undoubtedly require engine modifications. The engineering of these modifications will depend to a large extent on the laboratory test results. Since the field testing may reveal difficulties unforeseen in the laboratory, the coordination of a joint laboratory and field program will contribute to a rapid solution of any such problem. On a longer term basis with interest directed at eventually using 100% methanol in autos, the need for technical support of a laboratory program is mandatory.

The laboratory tests at General Electric involved burning methanol in individual combustors identical to those used in combustion turbines. More recently there have been operational tests made at Florida Power Corporation[33] involving burning of methanol for approximately 12 hours to generate electricity. These tests included starting and running a simple cycle machine converted to accept a flow of methanol greater than than that required for distillate. Owing to the standard pumps that were available at the time of the test, this combustion turbine realized only 85% of the maximum power output. This was not considered a significant problem. The combustion and emission characteristics of these methanol tests proved to be excellent.

The oxides of nitrogen were only 30% of #2 distillate fuel emissions. The carbon monoxide produced, although higher than for distillate, was well below the environmental standards. These CO emission results are at the same level of ppm as are obtained when water injection is used to suppress NO_x emissions with distillate fuel. Although the scope and duration of these tests was not sufficient to provide definitive data, no undesirable effects were observed. Localized high temperature areas or excessive deposits, erosion, or corrosion did not occur.

In view of these recent encouraging results with installed public utility combustion turbines, extended operating tests are now necessary to demonstrate over sustained periods that methanol is in fact an excellent alternative fuel to distillate and in many ways superior in performance. A demonstration of this nature must be of sufficient duration to reveal unforeseen problems as well as to permit the scaling of the results to larger capacity machines and to greater time periods. Examination of current practices with existing installations indicate that a 500 hour operation should provide the basis for a reliable analysis of methanol's performance in combustion turbines under load. Further discussions with turbine manufacturers and public utility personnel indicate that a unit of 20 or 30 megawatt capacity would be of sufficient size to allow the results to be scaled to machines of the 70 megawatt and larger size. A 500 hour demonstration test with this unit will consume approximately 2,000,000 gallons of methanol and should provide representative information on the interaction of this fuel with gaskets, seals, pumps, and associated plumbing of the system. Further information that would be forthcoming from this test would relate to storage facilities and handling of the methanol in a public utility environment. The latter is not expected to present major problems as combustion turbine manufacturers have had experience in developing and operating combustion turbines burning such fuels as naphtha which involves handling similar problems of an unusual nature.

SOURCES

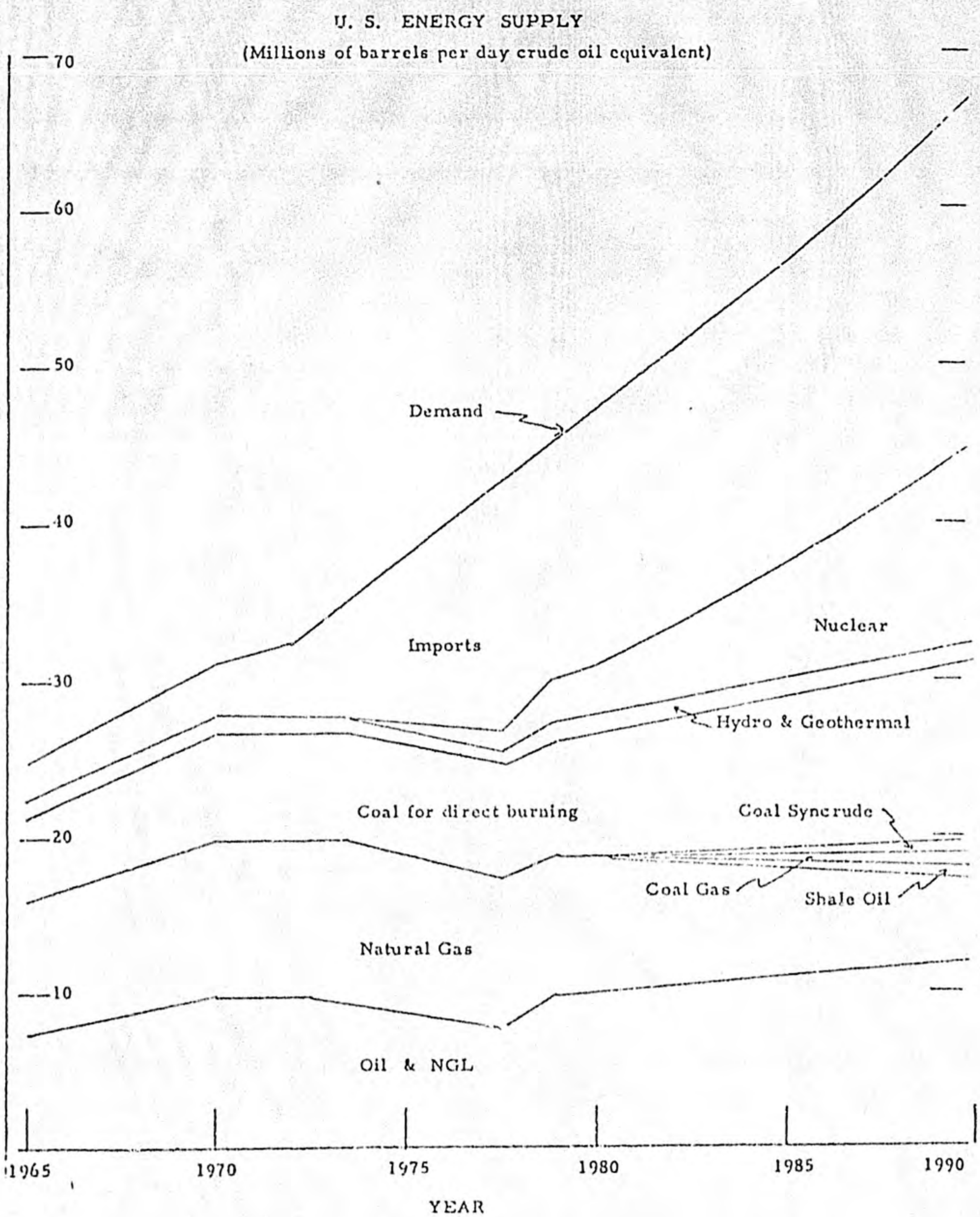
The principal problem associated with all synthetic fuels is that the source of the raw material is needed in very large quantities. Figure 2 shows the U.S. demand for energy and how it will probably be met through 1990. The only practical materials to be used as sources for synthetic fuels such as methanol are coal, natural gas, oil shale, tar sands, peat, forest products, agricultural materials and waste.

COAL

The known recoverable reserves of coal in the United States make it the primary source of energy. These reserves are estimated in hundreds of billions of tons (see Table) which by current annual consumption standards should be sufficient for over 300 years. It must be noted however that "coal" ranges in quality from so-called lignite through bituminous and sub-bituminous to anthracite. The aspects of quality not only involve energy content but also sulfur and water content as well as physical properties. In addition, there is a residual ash after processing which adds to transportation, disposal, and environmental problems. Fortunately all known forms of coal lend themselves to being converted into liquid or gaseous fuels by one or more chemical processes which substantially consist of the addition of hydrogen atoms to produce hydrocarbons.

Studies of constructing and operating methanol-from-coal plants indicates that mining operations and related activities for a 5,000 tons/day methanol plant plus associated SNG plant of 185 million cu. ft./day would

FIGURE 2



(Shell Oil - Mar. 1974)

require approximately 1000 operating employees.[1] Although this labor force would probably present fewer problems in an Eastern or Midwestern coal region, in the Western U.S. this would be a quite different situation particularly if the site is in a sparsely populated region. An in depth study is required to evaluate the regional social and economic implications of such an undertaking since the mine would be selected with the design of operating it for 20 to 30 years.

It is estimated that for a single plant such as the above an investment of approximately five hundred million dollars may be required including interest during construction.[1] By comparison a 1972 methanol plant of 80 million gallons annual output (700 tons/day) using conventional natural gas feedstock costs $60 million.[128]

The problem of using coal as a source of methanol is inherently wrapped up in mining or extraction plus gasification. Heretofore these two problems have been approached separately since for many years mining did not present the technological and economic difficulties that are involved when coal is converted to a usable gas for the synthesis of methanol and other liquid fuels. In recent years progress has been made in processes for gasifying large quantities of coal.[1,2] Unfortunately the coal extraction has not progressed as rapidly. During the past few years the annual production of underground mines has still exceeded strip mining tonnage. The difficulties in coal mining and extraction stem from limitations of underground and surface equipment, improvements in working laws and regulations, and shortage of miners. While strip mining personnel were continuously improving daily production per man, underground production fell off. Much of the fall off in production has been an outgrowth of the federal safety and health laws and regulations. Among eastern U.S. coal mining companies, many now have 5 year programs to again achieve the daily production of 15 tons per day per man they enjoyed in 1969 by upgrading underground equipment and methods. On a more forward looking basis there are development programs which are expected to be completed in the 1975-1980 period which, if successful, will involve controlled gasification of coal in-situ with recovery of the synthesis gas at the surface of the ground followed either by further processing at that site or pipeline distribution. Although the probability of success is uncertain the value if successful is so large to the nation that the program is worth pursuing. Most prominent among organizations taking this approach are the Livermore Applied Technology Group of ERDA.[12, 13] Conceptually in-situ mining is an important move. Placing additional manpower underground over and above the present 110,000 miners will not produce the extraction of 1.2 billion tons of coal recommended by Project Independence. Even if the initial tests prove successful the technique may not become commercially practical before 1990.

NATURAL GAS

Natural gas, from which methanol is produced is now in critical supply and will only be available in the near future in very limited quantities as a feedstock for methanol production. Although this material is a raw material for methanol its use for this purpose will be superceded by demands for other chemical production. As was mentioned earlier the known recoverable reserves are small compared to the annual consumption in the U.S. and may be exhausted in 10 years. There have been estimates made by the U.S. Geological Survey of undiscovered recoverable resources based on the frequent association of oil and gas that are usually present in large segments of the earth's crust. Generally 6,000 to 8,000 cu. ft. of gas is found with each barrel of oil.[58] Using the estimate of undiscovered recoverable resources of petroleum of 200 billion barrels and a ratio of 6,000 cu. ft. per barrel, a total of 1,200 trillion cu. ft.[58] should be undiscovered recoverable resources. Experts differ widely on estimates of undiscovered resources since there is a high degree of uncertainty involved. Among the considerations which must be recognized are that oil and gas are not always associated; also the several trillion tons of coal in the U.S. may contain as much as 8,000 trillion cu. ft. of entrapped methane gas; and some of the carbonaceous shales associated with coal may contain an additional 4,000 trillion cu. ft. of gas.[58] Clearly only a small percentage of this is recoverable and would probably not be available until beyond 1990. It has been well publicized however that about 260 trillion cu. ft. of methane gas is probably contained in the existing mapped and explored coal resources of the U.S. This is based on the U.S. coal resources of 1.3 trillion tons above 3,000 feet which are capable of being mined by underground methods. 200 cu. ft. of gas per ton of coal is considered a reasonable estimate. However again it is only a fraction of this gas that can be recovered since probably as much as 10 to 20% is retained in the coal. Consequently, any consideration of natural gas as a source material for methanol fuel must for practical purposes in the 1975-1980 time frame be confined to competing for the approximately 250 trillion cu. ft. of known recoverable reserves.

There is however an aspect of natural gas which must be examined more carefully. As recently as 1973 the U.S. was venting and flaring on shore over 250 billion cu. ft. of gas annually (1.1% of U.S. annual).[116] Offshore in the Gulf of Mexico in 1973 there was being vented and flared 57 billion cu. ft. according to studies of the U.S. Geological Survey.[44] The economics of using this offshore natural gas involves the cost of building pipelines into the Gulf and pressurizing it in order to introduce it into an existing pipeline. Consequently beyond a specific offshore distance it is not economically practical to bring the gas ashore. However, it may be feasible to collect this gas and manifold it offshore at which point it could be processed in a barge mounted plant into a liquid fuel such as methanol. Since accelerated offshore petroleum drilling is imminent, the merits of conducting such an analysis are obvious. The USGS estimates for the offshore U.S. are between 131 and 1,031 billion barrels of petroleum liquids and between 676 and 2,328 trillion cu. ft. for natural gas. The current vent and flare gas in the Gulf of 57 billion cu. ft. is 2% of the 1973 production in the Gulf of 2,882 billion cu. ft. By comparison this would indicate there is a possible 13 trillion to 26 trillion cu. ft. or 2% that may be ultimately vented and flared offshore U.S. that could be collected for synthesizing liquid fuels such as methanol.

SHALE

The availability of energy from oil shale has been well known for many years. From time to time especially during periods of oil shortage there has been considerable interest in mining and extracting oil from them. Geologists and petroleum engineers differ as to their estimates of the oil that can be recovered from U. S. sources. Among the difficulties involved in making accurate estimates is the variation in oil content of these shales. It is as low as 0 in some areas and reaches as high as 60 gallons per ton in others. In the major Colorado, Utah, and Wyoming basins where these shales are predominant, 25 to 65 gallons per ton is the range of yields. These three areas are estimated to contain deposits of 600 billion barrels of petroleum. However for economic reasons exploitation must be directed at the higher grade shales (averaging 30-35 gallons per ton) which lie in beds at least 25 feet thick and within 1,000 feet of the surface. Estimates indicate approximately 160 billion barrels are available. Further studies on the practical aspects of recovering this oil point to possibly 80 billion barrels as being available. An indication of the poor prospects of this material as an economic source of energy are the estimates for utilizing the oil shale in the well known Green River formation of Colorado, Utah, and Wyoming. Of 1,800 billion barrels of total oil content, all except 5% is considered to be too low grade, too deeply buried, or too poorly defined to be worth developing. If this 5% or 90 billion barrels is further restricted for economic purposes to beds at least 30 feet thick with average oil content of at least 30 gallons per ton, it has been calculated that by means of known underground mining methods 60% or approximately 50 billion barrels of the inplace oil can be recovered.

The National Petroleum Council has made a study of those shale deposits that could be considered for successful exploitation before 1985. Their conclusions show that the only area to merit consideration is the Piceance Basin of Colorado in which they estimate 20 billion barrels could be extracted.

The use of oil shale as a source material for oil or methanol presents many chemical engineering problems. Shale does not contain oil, but rather a material known as kerogen composed of carbon, hydrogen, nitrogen, sulfur, and oxygen. There is little geological relationship between shale oil and petroleum. The kerogen of the average rich kerogen shale is intimately mixed with inorganic clays, sands, and carbonates. Owing to the approximately 10% nitrogen and 1% to 8% sulfur contained in the kerogen, both must be removed before it can be converted to petroleum.

Effective methods and techniques have been developed for mining, crushing, and heating oil shale. One such consists of pulverizing the shale in a kiln by means of heated ceramic balls which reduce the shale to the consistency of talcum powder while bringing it up to an elevated temperature. Owing to an approximately 10% increase in physical dimensions in the extraction process, the shale presents a waste disposal problem as yet unsolved. A projected 50,000 barrel per day plant in Colorado which will mine a 4,000 acre region estimated to contain 800 million tons of oil shale with 30 or more gallons of recoverable crude will need to process 70,000 tons of shale per day.[61]

Although petroleum from oil shale may ultimately be commercialized, the prospects of utilizing this as a source for petroleum or synthetic fuels prior to 1985 are remote. To put this industry into proper perspective with our current economy, if the nation wished to obtain 1 million barrels per day of petroleum from oil shale, it would require mining approximately 1.4 million tons of shale per day. This is equivalent to developing a shale mining operation equal in size to the entire present U.S. coal business.

TAR SANDS

The tar sands as a source raw material for producing synthetic fuels such as methanol offer a more unattractive situation than oil shale. The U.S. deposits are quite small and estimated at a few billion barrels for known recoverable reserves and possibly 10 billion barrels for undiscovered marginal and submarginal resources not economically recoverable at present. For over 50 years several small scale efforts to utilize these sands have been made and failed. The most recent effort pursued by Great Canadian Oil Sands Ltd.[124] has incurred large financial losses while conducting an open pit mining operation producing 50,000 barrels per day. The possible use of in-situ mining of these sands is currently being explored.

AGRICULTURAL AND FOREST PRODUCTS WASTE

One of the most promising means of producing methanol is to source it from agricultural and forest products and waste. This is in essence utilizing solar energy to provide a continuously renewable supply of raw materials. The attractiveness of this approach has many obvious merits. The raw materials are renewable and can be collected with fewer problems than those associated with underground mining, the renewable materials are geographically mobile, and the total system contributes to less pollution of the environment.

The Office of Energy Resources of the State of Maine[67] has made an analysis of converting the state's wood and wood waste to methanol. They have concluded that 3 tons of wood will yield approximately 0.86 tons of methanol. The wood is first converted to synthesis gas by partial oxidation yielding approximately 0.7 tons of gas for 1 ton of wood waste plus 0.2 tons of oxygen. The synthesis gas is then converted to methanol using the water-gas shift reaction. The yield is approximately .28 tons of methanol per ton of wood.

Maine has 17 million acres of forest land from which 3.2 million cords of pulpwood and 0.41 million cords of lumber are taken each year (10 million tons green). The annual rate of removal amounts to 0.5 cords per acre since harvesting is conducted on only a smaller fraction of the land. In addition to this removal of timber, there is a substantial amount of slash, dead trees, limbs, and material under 4 inches in diameter left behind. Estimates indicate about 40% of the tree is not removed from the woods. Consequently in addition to the wood removed, there are approximately 3.8 million tons per year of wood trash from the trees which are actually cut. (1 cord dry weighs approximately 1.5 tons; 1 cord green wood weighs 2.9 tons.)

In addition to the slash there are substantial quantities of dead and diseased trees, scrub growth, and other growth not harvested. This has been estimated to be 15% of the total volume removed for commercial purposes. However experts differ on these figures, Studies performed by the State of Maine in the field through interviewing techniques with foresters show that a minimum of 5 cords per acre per year of wood could be taken out continuously from Maine woods.[67] It must be pointed out that current forestry practices, procedures and methods would need to be altered to achieve this level.

There are in addition to the above mill wastes and sawdust which are unutilized. When the national statistics on these wastes[83] are translated into Maine's operating level, it appears that there should be some 1.2 million tons of unutilized mill residues available annually for use as feedstocks for synthetic fuel manufacture.[66]

Supplementing the slash and mill wastes, Maine has 5 million acres of spruce-fir forests infested with the spruce budworm. This diseased timber is now in its third year and after six years of infestation it is expected to have almost no commercial value. The total quantity of wood involved including the commercial as well as the slash is about 208 million cords (312 million tons). At such time as the timber is no longer of value for pulpwood or saw logs it is still acceptable for use as a chemical feedstock. This quantity of wood is capable of being converted into 89 million tons of methanol (27 billion gallons.).[67]

Present plans to construct a hydroelectric dam on the St. John River in Maine (Dickey-Lincoln Reservoir) will flood 86,000 acres of woodlands. There are 5.5 million tons of wood in trees which would be harvested under normal circumstances. This wood can be converted into[67] 1.58 million tons (480 million gallons) of methanol. In addition there is the growth not normally harvested which could be cut. This quantity approximately equals that of the wood harvested.

In summary the Maine forests have the potential to yield the following quantities of methanol:

Source	Quantity of Wood (millions tons/yr)	Quantity of Methanol	
		(millions tons/yr)	(million gal/yr)
Slash and logging waste from present practices	3.8	1.08	328
Potential slash, brush, waste wood 5 cords/acre/yr on 17 million acres	132	38	11,500
Unused mill wastes and and sawdust	1.2	.34	103
TOTAL	137.0	39.42	11,931

On a continuous basis these forests can provide 39.42 million tons (11.931 billion gallons) of methanol per year. This represents 1200% of present total U.S. production.

There is provided by the diseased timber situation and the hydro-electric project a one time opportunity to produce 90.5 million tons (27.48 billion gallons) of methanol which is equal to a 25 year supply at current U.S. production rates (Table VI).

Spruce budworm infested area	312 million tons of wood	89 million tons of methanol	(27.0 billion gals.)
Dickey-Lincoln flood area	5.5 million tons of wood	1.5 million tons of methanol	(480 million gals.)
TOTAL	317.5 million tons of wood	90.5 million tons of methanol	(27.480 billion gals.)

MUNICIPAL SOLID WASTE

The solid waste explosion in municipalities has become a major problem for environmentalists and local governments. The conventional approach to obtaining a solution has been to acquire additional land areas for the land fill operation. However this practice is being greatly restricted as acceptable sites must be located at greater distance from the urban areas. Concurrently with public concern over the solid waste situation is the recognition that this waste is a potential energy resource which is being lost. The City of Seattle[76,77,78] has investigated the technical feasibility of gasifying municipal solid waste and synthesizing methanol or ammonia from the gas produced. The process considered is essentially the Purox process of Union Carbide Corporation. They have also examined the technical feasibility of using methanol as a fuel substitute in city vehicles and other applications. Plants capable of processing 600 tons per day and

1, 500 tons per day were considered in the analysis. The larger plant resulted in more favorable economics. A 1, 500 tons per day plant using the Seattle waste composition would produce about 83, 000 gallons (280 tons) per day utilizing the Imperial Chemical Industries low-pressure process for synthesizing methanol. This is a 19 % yield per ton of wet refuse. The composition of the average day's refuse feedstock was determined to be 47% carbon, 33% oxygen, 6% hydrogen, 1. 2% nitrogen, 0. 3% sulfur, and 12% ash. Depending upon various compositions of their refuse (25% to 30% weight moisture) Seattle found yields varied from about 16. 9% to 21. 5%. The cellulose content of solid waste and ultimately of course the carbon content determine the amount of methanol or ammonia that can be produced. Consequently any potential local legislative action or economic constraints which would result in an alteration of waste composition would produce a change in yield. Similarly any major seasonal variation in the content of the municipal waste would have an effect on the yield.

The City of Seattle's analysis indicated that the success of this type of enterprise rests heavily upon obtaining favorable long-term committments for the purchase of methanol and ammonia. Both methanol and ammonia historically have fluctuated widely in price; the former having swings as great as 10 cents to 48 cents per gallon in recent years. These swings are coupled with reduced and excessive demand for these two chemicals which serves to contribute to the difficulty of making this a viable business. A second key factor in the economics is the acceptance by the municipality of the need of a financial credit for solid waste disposal to offset production costs of methanol and ammonia. Not only is this a credit for refuse collection but also for reducing the daily tons of municipal waste going into a city's landfill. The City of Seattle in its analysis considered a $4.90 per ton credit for waste processed. It was found that without this credit that too high a market price must be realized for methanol and ammonia.

The total municipal waste currently being generated in this country has been estimated[68, 117] at between 3.0 and 3.6 lbs. per person per day. This would project to a total national figure of approximately 140 million tons per year in 1974. On the basis of a 19% yield on conversion to methanol, this quantity of municipal waste would yield a potential 26 million tons (7900 million gallons) per year.

WOOD WASTES

The total U.S. growing stock logging residues in 1970 totaled 20 million cords (30 million tons)[83] of which about one-third was located on the Pacific Coast. In addition to these, a recent study[83] on the Pacific Coast indicated that residues from nongrowing stock approximately equaled those above from growing stock.

The north coastal region of California is a major source of wood residue created by their large logging operations. The largest percentage of this waste is either burned or used as landfill. This material is created seasonally and heretofore has received little attention as collection and conversion costs required investments in capital equipment which would only be used a part of each year. The use of mobile processing units may make the use of this waste material economically feasible.

A survey[21] of the North Coastal Regional timber industry indicates that over 1,161,000 tons of wood waste is created annually. In the Six River National Forest an average of 70 tons per acre of residue were reported on a total of 4,150 acres cutover each year.

The California Forest Protective Association and the Western Timber Association[21] through a survey of 69 members estimate this wood waste can be loaded for an average of 50 cents per ton. They further estimate it can be hauled out of the woods for 30 cents per ton mile. These are average values and vary greatly between the lowest and highest estimates.

The Select Committee of Manpower Development[21] and the Select Committee on North Coast Timber Economy[21] have developed plans to construct a mobile pyrolysis-distillation system plant which would move by rail and utilize flat cars and tank cars. As wood waste is consumed in an area the unit would be moved to another site.

The North Coastal area annually produces sufficient wood waste to support an operation producing 400,000 tons per year of methanol (120 million gallons). A further analysis will be required to determine if the plant investment and operating costs will result in a methanol cost that is competitive with other sources. (See Table VI)

On a national basis the potential of methanol from wood appears very favorable. The 500 million acres of U.S. commercial timberlands contain some 715 billion cubic feet of sound wood. This represents approximately 25 billion tons of wood (wet). 649 billion cubic feet are growing stock and 66 billion are nongrowing. The annual growth of these timberlands is estimated to be some 18.6 billion cubic feet (670 million tons). This total inventory does not include wood in limbs and stumps nor that on land classified as non-commercial. (Commercial timberland by definition has the capability of producing in excess of 20 cubic feet per acre per year of industrial wood in natural stands.

Currently from this forest inventory there is harvested annually 12 billion cubic feet (420 million tons) of wood of which 11 billion is from growing stock and 1 billion from nongrowing stock of rough, rotten, and salvable dead trees. The logging residues from the growing stock constitute 5 to 10% of that harvest and amount to 1.6 billion cubic feet. Another 1.6 billion cubic feet of residues is estimated to be produced by the nongrowing stock. Much of this residue is unutilized since it is unsuited for most purposes other than pulp or particleboard.

The primary processing plants and sawmill operations also produce wood waste as was mentioned earlier. Two of the principal uses for these plant wastes are wood pulp, fuel, and particleboard which consume 2.8 billion cubic feet (52 million tons). There remains however 1 billion cubic feet (19 million tons) annually unused at the sawmills and other plants plus the annual volumes of unused residues from the past. Additional residues accumulating at these primary plants and mills are some 2 billion cubic feet (38 million tons) of bark which currently constitutes a waste disposal problem. At present approximately 70% of this material is burned or dumped.

In addition to primary plants and sawmills there are secondary plants creating wood residues. The U.S. annual production of these residues is estimated at 900 million cubic feet (19 million tons) most of which is unused. In general much of this residue is burned or dumped as waste. Precise figures on any secondary use of these residues are not available.

In summary, on an annual basis there is available in the U.S. from unutilized forest waste the following:

3.2 billion cubic feet of logging waste

1.0 billion cubic feet of primary plant waste; slabs, edgings, sawdust, veneer cores

2.0 billion cubic feet of primary plant bark

.9 billion cubic feet of secondary plant waste; shavings, trimmings, sawdust

Total = 7.1 billion cubic feet = 130 million tons of wood which can be converted into 38 million tons of methanol

It should be noted that none of these residue figures take into consideration the forest waste from previous years since only Maine and Northern California have been able to collect data as to the quantities available.

PEAT

The large supplies of peat throughout the world make it a potential source material for conversion to methanol. U.S. and Canada have approximately 37,000 and 11,000 square miles respectively of peat bogs varying in thickness from 5 to 25 feet. Peat is a product of decayed vegetation which was originally reeds, rushes, sedges, and mosses and analyses have shown carbon contents of the order of 60% in specimens dried at elevated temperatures. The water content is generally high and in low lying bogs may be 90%. The high water content and the need for drying has limited the commercial success of peat as a fuel. Average air dried peat of 25% moisture has been found to have 6,000 BTU per lb.[84]

Measurements in Germany of peat production (peat-winning) have been made. It was found that approximately 800,000 tons of air-dried peat are obtained per square kilometer in beds about 16 feet deep. (2.1 million tons per square mile.) For an assumed average depth of 5 feet for the U.S peat beds, calculations indicate the total supply to be 6.5 billion tons if the density and composition are that of the beds in Germany.

An early Ziegler process in Germany which focused on the pyrolysis and partial oxidation of peat have reported methanol yields of 65 gallons per 100 tons of air-dried peat.[84] This process however was concerned with other by-products and uses for peat rather than obtaining methyl alcohol. In view of the high carbon content of peat and the vast resources in the U.S., a more detailed analysis of applicable processes should be made to obtain data on yields of methanol and costs.

Total potential methanol yield is 4.2 billion gallons from U.S. peat.

FEEDLOT MANURE

The development of large cattle feedlots has produced the accumulation of large concentrations of manure in various sections of the country. Available figures indicate that some 28 million tons per year are generated of which possibly one-half is water. The Department of Agriculture statistics show that approximately 14 million head of cattle are now feeding in concentrated areas and are producing manure at a rate of 2 tons per year per head. The operators of these facilities are faced with the problem of disposing of this material as it has become costly to truck it to farms at any distance; the polluting effects of runoff after a recently fertilized land are objectionable; commercial fertilizers are preferable both economically and biologically; and some of the nutrient additives to the animal feed are undesirable waste products. Most disposal plans involve some type of chemical treatment, incineration, or land disposal method. Since this material is rich in cellulose, investigations have been directed at gasifying manure to produce a synthesis gas suitable as a feedstock for methanol or ammonia production. The Bureau of Mines reports having pyrolyzed cow manure at 400° to 900° C. to yield 11,000 scf of gas per ton. The reaction products contained 16.8% CO, 27.5% H_2, and 23.5% methane. The manure processed contained 3.6% water.[46,47,48,115]

The larger concentrations of cattle may number as high as 750,000. Studies have been made of somewhat smaller groups of the order of 200,000 head where the production of manure would be of the order of 1000 to 1200 tons per day. This capacity processing plant was selected as a tradeoff between transportation costs to collect the feedlot waste and the economies of scale in plant size.

The process used by investigators has followed the lines of municipal solid waste conversion to a synthesis gas. The manure is ground, dried to about one-half of its original water content, and then fed to a pyrolysis unit at atmospheric pressure where it is heated to 1500° F. The reaction products are primarily CO, CO_2, H_2, and CH_4 plus char. The solids are physically separated and the CO_2 is chemically absorbed in a hot potash absorption process leaving a gas made up of CO, H_2, and CH_4. The process generated about 166 tons of synthesis gas from a total of 1100 tons of feedstock. Since the manure was approximately 50% water, the process produced about a 30% yield of gas based on dry manure. The heat of reaction of the manure was estimated to be 1110 BTU per pound at 1500° F.

In view of the quantity of raw material available yearly which on a dry basis is 14 million tons, it will require an economic analysis in depth to determine if this is a viable route to pursue for the conversion of feedlot waste to fuel. The process yields of methanol are likely to be low and the cost of feedstock is as yet an unknown quantity.

The gas produced has a composition of 42% CO, 44% H_2, and 13% CH_4. If it is assumed the synthesis gas generated can be suitably shifted in composition and converted to methanol on a 50% yield basis, the 1100 tons per day plant would yield 83 tons of methanol. This is an overall yield of 7.5% on a wet manure basis. Using the national figure of 28 million tons of feedlot waste available annually, the total U.S. potential for methanol production would be 2.1 million tons (620 million gallons) from this source.

SOURCES OF METHANOL

Material	Availability	Conversion	Quantity of Methanol (Millions) Tons/Yr	Gal/Yr
Coal	"Unlimited"	1 ton to .6 ton	"Unlimited"	
Offshore Vent & Flare Gas	52×10^9 cu. ft./yr.	65%	1.6	485
Total U.S. Municipal Solid Waste	140×10^6 tons/yr.	1 ton to .19 ton	26	7,900
Calif. North Coast Timber Waste	1.16×10^6 tons/yr.	1 ton to .3 ton	.4	120
Maine Woods Slash & Waste	3.8×10^6 tons/yr.	1 ton to .3 ton	1.08	328
Maine Woods Potential Waste on 17 Million Acres	132×10^6 tons/yr.	1 ton to .3 ton	38	11,500
Maine Un-utilized Mill Wastes & Saw-Dust	1.2×10^6 tons/yr.	1 ton to .3 ton	.34	103
U.S. Total Unutilized Mill Wastes, Saw-Dust, Logging Waste	7.1×10^9 cu. ft./yr. (130×10^6 tons)	1 ton to .3 ton	38	11,500
Maine Spruce Budworm	312×10^6 tons (available one time)	1 ton to .3 ton	89 tons	27,000 gal
Dickey-Lincoln Dam Flood Area	5.5×10^6 tons (available one time)	1 ton to .3 ton	1.5 tons	480 gal
Peat	6.5×10^9 tons (available one time)	1 ton to .0021	13.8 tons	4,200 gal
Feedlot Manure	28.0×10^6 tons/yr.	1 ton to .075	2.1	620

DEMAND

The consumption of fuel for transportation and electrical generating purposes has been growing at a substantial rate owing to the increase in number of vehicles, size of vehicles and engines, transportation needs of the population and the demands of a society heavily dependent upon electrical power. In recent years the total petroleum used in the U. S. can be grouped into the following major consuming areas:

Daily Consumption of Oil

Residential and Commercial	18%
Industrial	11.5
Electrical Energy Generation	7.0
Non-Energy Applications	10.5
Transportation	53.0

The 53% used for transportation translates into an annual usage of approximately 115 billion gallons of gasoline, diesel fuel, kerosene, aviation turbine fuel and other hydrocarbon fuels produced from petroleum. The total consumption of energy for transportation is actually somewhat higher since the natural gas (non-petroleum source) and the electrical energy contribution raise the figure slightly.[7]

Of the total energy consumed for fuel, estimates indicate that the following quantities of gasoline, kerosene, and distillate were used by motor vehicles (both highway and non-highway).

U. S. TOTAL FUEL SUPPLY AND DEMAND
(000,000 Barrels)

	Gasoline		Kerosene		Distillate Fuel Oil		Residual Fuel Oil	
	Produced	Demand	Produced	Demand	Produced	Demand	Produced	Demand
1950	1,024	1,019	118	120	399	75	425	570
1960	1,522	1,525	137	133	667	695	332	578
1965	1,733	1,756	202	220	765	780	268	602
1970	2,135	2,165	313	358	897	927	257	804
1971	2,231	2,242	306	365	912	971	275	838
1972	2,352	2,382	313	379	963	1,066	292	925
1973	2,435	2,464	328	383	1,030	1,124	345	1,019

Investigators have already forecast that this consumption for transportation will become 11.5 million barrels (480 million gallons) equivalent per day in 1980.

PUBLIC UTILITIES

The U.S. electrical energy generation currently uses the energy[7] equivalent of 7.1 million barrels of oil per day of which 1.2 million is actually oil. 21% of this usage or .252 million barrels per day is consumed in the combustion turbines of public utility plants. By 1980 the total electrical energy generation requirements will reach 13.2 million barrels of oil equivalent per day. The combustion turbine requirements in that year are estimated to be 1.0 million barrels daily (42 million gallons).[1] Since methanol has 50% of the energy of distillate, this represents a requirement of 2.0 million barrels (84 million gallons) daily if all distillate peaking turbines were converted to methanol.

A potential problem area exists as regards the high demand for raw materials by the public utility and the steel industry. Public utilities consume annually approximately 250×10^6 tons of coal which is close to half of all the coal used in this country. The steel industry, which requires approximately 1 ton of coal (or equivalent energy) for each ton of steel produced, uses in excess of 100×10^6 tons of coal per year. This accounts for approximately 20% of the annual output of coal. As a result a new major demand for coal as a raw material for methanol production will be constrained as much by increasing industrial and public utility pressures as by mining limitations mentioned earlier.

CHEMICALS

A third area which will undoubtedly contribute to a competitive situation is the demand for methanol for chemical purposes. The United States consumption of methanol has been increasing at a rate of 8.5% annually for the past 10 years. Of the 1 billion gallons annually produced, 50% is as an intermediate for formaldehyde manufacturing, 10% in solvents, and 5% in the production of dimethyl terephthalate for textile fibers. Of the remaining 35%, the usage is almost equally divided among the acrylics (10%), the insecticides (10%), and the fungacides (10%) production together with 3% exported and 2% for a variety of miscellaneous chemical and fuel applications. (See Figure 3.)

Formaldehyde which accounts for approximately half of all the domestic methanol demand has been growing rapidly. Formaldehyde

ANNUAL CONSUMPTION OF METHANOL IN U. S.
(1 BILLION GALLONS)

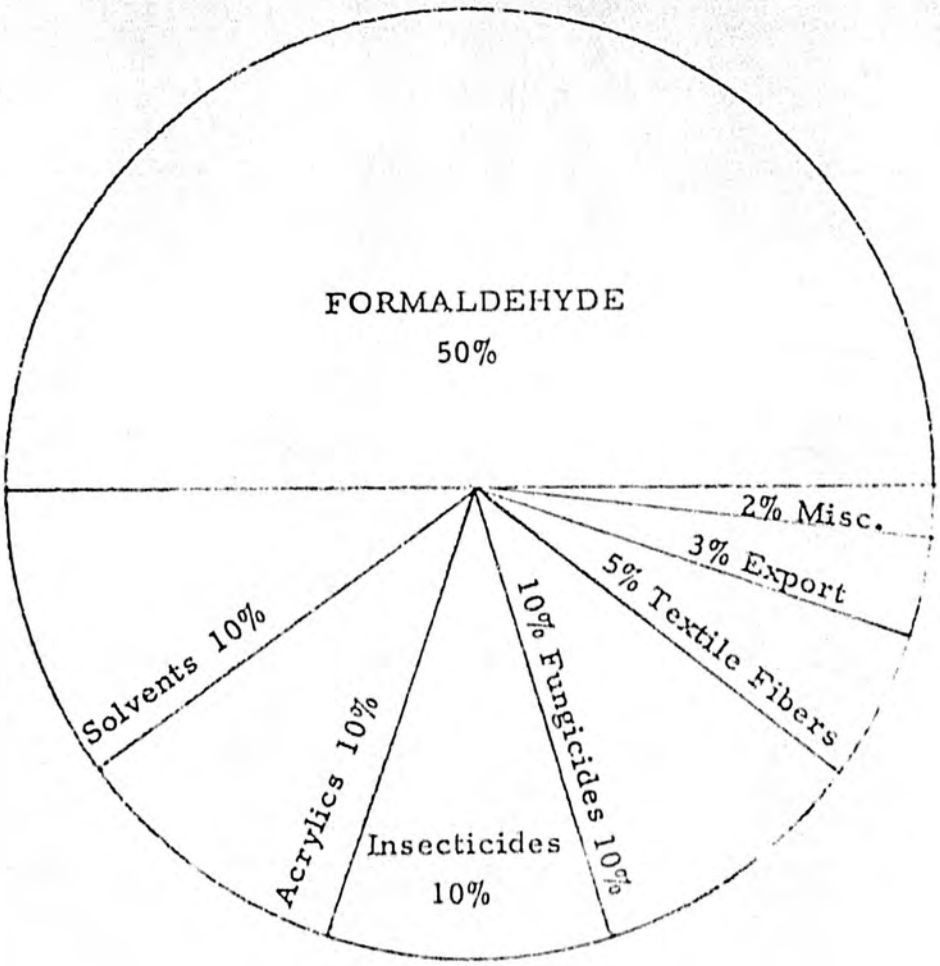


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FIGURE 3

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solution which is produced in excess of 5 billion pounds annually is used extensively in adhesives in particle boards and plywood manufacturing and hence is keyed into construction. Most methanol producers manufacture formaldehyde. Of the 18 formaldehyde producers in the U.S., seven do not have captive supplies of methanol. In addition to the formaldehyde market, the solvents market using methanol is growing as well as the[11] demand for dimethyl terephthalate. The former is used extensively in industry as a solvent for extracting, washing, drying, and crystallizing owing to its low price, high purity, and excellent properties. The latter is used widely as an intermediate in polyester fiber manufacturing. Production of dimethyl terephthalate is currently in excess of 1.5 billion pounds each of which utilizes 0.2 pounds of methanol.

CONVENTIONAL FUELS

Methanol as fuel for a conventional fired boiler has been successfully used in a test by a New Orleans public utility. The clean burning[34] characteristics were particularly encouraging. Although a potential large user of this fuel, the economics of this application are not encouraging when compared to other fuels for this use. The direct firing of the boiler with coal is superior economically than using as a fuel methanol produced from the same coal. Methanol derived from high sulfur coal would need compete with high sulfur coal plus scrubbers.

Less known but a potential user of methanol is the residential fuel business in rural areas. Although chemical companies are using 25% of propane production as a raw material, the bottled fuel business is using 50% of the U.S. production of approximately 900,000 barrels (37.8 million gallons) per day and has held fairly constant for some time at about half[42] of this total. This fuel is used for home heating, water heating, and cooking. Propane has enjoyed considerable success as a fuel owing to its ease of distribution since its cost at the extraction plant was approximately 3 cents per gallong until the recent upsurge in demand began. About two-thirds of propane consumed comes from natural gas and the remainder from refining petroleum. (Imports are on the average of 43,000 barrels (1.8 million gallons) per day.) As a consequence of limits on natural gas and petroleum plus proposals to use propane to make SNG, the entire demand pattern is changing.[43] Unfortunately the chemical companies cannot readily shift to an alternative such as naphtha, for example, as it would double their investment to convert and would require two years. As a replacement for propane, methanol is an excellent, clean fuel particularly because of the continuous rise in the price of propane, and the simplicity in making the conversion from propane to methanol, and the ease with which methanol can be stored and distributed economically. Additional uses of propane as a fuel that could be met by methanol are in crop drying operations and poultry breeding. These are small but significant uses of propane.

COSTS

The Atomic Energy Commission and Esso Research and Engineering have calculated for large plant facilities that methanol produced in 1973 from natural gas at 40 cents per 1,000 cubic feet would cost in the neighborhood of $1.50 per million BTU at the plant.[3,10] However owing to the rapid increase in construction costs in 1974 and the forecast for continued high costs, this figure is uncertain as far as the future is concerned. The AEC[1] calculates methanol produced from strip mined Western coal delivered at 20 cents per million BTU or produced from deep mined Eastern coal at 35 cents per million BTU on a scale of at least 5,000 tons per day will have a cost of $2.12 per million BTU for the former and $2.44 per million BTU for the latter.[1] The financing in this case would be utility financing at 10.5% return on rate base. The process selected, siting, coal type and cost, construction costs, and financing methods all clearly influence the cost of the methanol. The above two cases if investor financed at 12% discounted cash flow would yield methanol at $2.73 and $3.06 per million BTU.*

By way of comparison, gasoline at 19 cents to 25 cents per gallon (Jan.-Feb. 1974 cost at refinery) is in the range of $1.52 to $2.00 per million BTU.

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*Since the AEC computations were made utilizing the Koppers-Totzek coal gasifiers and the thermal efficiencies and capital costs are comparable, it can be seen that a difference of 15 cents per million BTU in coal costs produce a cost differential of 32 cents per million BTU. This is equivalent to a 2 cent differential on a gallon basis.

A number of other studies have been made focused on methanol production costs from coal and also from municipal solid waste. The Methanol Production Costs tabulation below shows the results of four of these studies: the AEC analysis using the Koppers-Totzek gasifier for Eastern bituminous coal plus the Imperial Chemical Industries methanol synthesis process;[1] an Oak Ridge National Laboratory Study[49, 111] of a plant process to produce 12,500 tons of methanol annually from bituminous coal (scaled down from 20,000 tons); an AEC analysis[1] using the Winkler gasifier for Western subbituminous coal in conjunction with the ICI methanol synthesis process; and a City of Seattle study[19, 76] employing the Union Carbide Purox process to pyrolyze municipal solid waste followed by synthesis of methanol from the gaseous products of the pyrolysis. In view of the wide range of premises that are involved in these studies, an additional tabulation of assumptions have been included.

The Methanol Production Costs tabulation has been constructed to provide information in 3 principal areas: total capital investment, annual operating costs exclusive of input feed stock, and cost of feed stock and energy. In addition to this information, there is included for each of the 3 areas the costs per million BTU output. The total of these last 3 costs provides the total cost per million BTU of methanol produced.

In order to avoid reconciling differences in methods of financing between studies, the capital costs per million BTU of methanol produced were determined in all cases by using 15% of the total capital investment as the annual capital cost. This is 10% for return on capital and 5% for depreciatio

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METHANOL PRODUCTION COSTS

		AEC	ORNL	AEC	SEATTLE
1.	Energy Output	5000 tons/day (1×10^{11} BTU)	12,500 tons/day (2.5×10^{11} BTU)	5000 tons/day (1×10^{11} BTU)	300 tons/day (5.6×10^{9} BTU)
2.	Gasification Process	Koppers-Totzek	(Ref. III)	Winkler	Purox
3.	Input Fuel	9900 tons/day (2.1×10^{11} BTU) Eastern Bit. Coal 21.3×10^{6} BTU/Ton	14,900 tons/day (3.7×10^{11} BTU) Eastern Bit. Coal 25×10^{6} BTU/Ton	13,700 tons/day (2.37×10^{11} BTU) West. Subbit. Coal 17.2×10^{6} BTU/Ton	1500 tons/day (15×10^{9} BTU) MSW 5000 BTU/Ton
4.	Thermal Eff.	46%	60-67%	41%	38%
5.	Capital invest. ($ Million)	253	279-364	241	56
6.	Ann. Oper. Cost ($ Million) Exclud. Coal	24	44	20	6.1
7.	Capital Costs Per Million BTU Output (at 15% per Yr.)	$1.12	$0.51-.66	$1.08	$4.10
8.	Operating Costs Per Million BTU Output (Ex. Coal)	$ .72	$ .53	$ .60	$2.44
9.	Input Fuel Costs Per Million BTU Output	$ .73	$ .53	$ .47	$ 0
10.	TOTAL COSTS Per Million BTU Output	$2.57	$1.57-1.72	$2.15	$6.54

As would be expected, the Seattle study results in a considerably higher cost of methanol since the plant capacity is an order of magnitude smaller than that of the other three studies. The latter enjoy the economies of scale both in capital investment and operating costs.

The studies tabulated were selected particularly because they produced predominantly methanol. One of the difficulties in comparing various techniques for converting such materials as coal to methanol is that many processes yield a wide mix of fuel products whose economic evaluation complicates the determination of the cost of the methanol.

Each of the above plant costs were calculated[111] with slightly different assumptions. For example the two 5000 ton/day plants include in the total capital requirements a 10% project contingency on the plant investment while the 12,500 tons/day operation includes a 15% contingency on the total capital investment required. Interest during construction of the two 5000 tons/day operations was assumed as 9% per year of the total plant investment over a 1.875 year period; for the 12,500 tons/day plant, 15% interest is used during the construction period; for the 300 tons/day operation, interest during construction of 2 years was assumed at 8% per year of the construction costs. Summarized below in tabular form is a comparison of the assumptions employed by the referenced investigators in performing their calculations of the cost of methanol per million BTU.

TABLE OF ASSUMPTIONS

	AEC	ORNL	SEATTLE
A.	No Inflation Assumed	No Inflation Assumed	10% per year inflation allowance applied to 2 yr. period plant construction and storage; 4% inflation rate thereafter
B.	9% per year of total plant investment for average of 1.875 years	15% interest during construction	8% interest for 2 years during construction
C.	10% of total plant investment assumed on project contingency	15% for contingencies	10% of total capital requirements assumed on project contingency
D.	(Not Identified)	(Not Idencified)	2% of total capital requirements assumed on cost to obtain money
E.	20% of total gross oper. cost is start-up cost	5% start-up cost	Unknown start-up cost
F.	2% of total plant investment is working capital	7 1/2% working capital	$1,000,000 working capital arbitrarily assumed
G.	90% plant service factor (330 days)	90% plant service factor (330 days)	100% plant service factor (365 days)
H.	Eastern Bituminous Coal Cost: 35 cents per million BTU ($7.35 per ton) 21 million BTU per ton as received; Western Subbituminous Coal: 20 cents per million BTU ($3.40 per ton) 17 million BTU per ton as received.	Eastern Bituminous Coal Cost: 32 cents per million BTU ($8 per ton) 25 million BTU per ton	Municipal solid waste at zero cost
I.	9% per year on debt	Capital costs of 15%/yr of total capital investment	8% revenue bonds for 15 years used to finance project
J.	All costs are 1973 dollars	All costs are 1973 dollars	All costs are 1974 dollars
K.	Maintenance labor at 1.5% of total plant cost	Unknown labor cost	Maintenance at 3.0% of total plant cost
L.	Process operating labor at $5/hr.	Unknown labor cost	Process operating labor at $10/hr.

The ORNL plant which was originally calculated[49] at 20,000 tons/day of methanol was scaled by investigators to a 12,500 tons/day methanol plant.[111]

In order to secure a more comprehensive comparison of costs for various plant capacities, the preceding data of various investigators is scaled below to a common 15 billion BTU/day energy input plant. This size plant is equivalent to a 1,500 tons/day municipal refuse plant using a feed stock of 5,000 BTU/lb. The plants are scaled using the typical 0.6 power investment cost change for changes in plant size. Thus,

SCALING FACTOR

AEC (Koppers-Totzek)	$(2.1 \times 10^{11}/15 \times 10^{9})^{0.6}$	= 4.86
ORNL	$(3.7 \times 10^{11}/15 \times 10^{9})^{0.6}$	= 6.82
AEC (Winkler)	$(2.37 \times 10^{11}/15 \times 10^{9})^{0.6}$	= 5.25
SEATTLE (Purox)		= 1.0

When these factors are applied to scale the capital investments (line 5.) of the earlier table on Methanol Production Costs, the following results are obtained:

TOTAL CAPITAL INVESTMENTS SCALED TO 15 BILLION BTU/DAY

($ Million)

A.E.C. Koppers-Totzek	ORNL	A.E.C. Winkler	SEATTLE Purox
$52	$41-53	$46	$56

This is of course a major extrapolation in plant design size and must not be accepted as a rigorous calculation. Furthermore the design figures for 5000 tons/day methanol plants are in themselves only approximations since no plant of this capacity has been constructed to produce methanol either from natural gas or coal. However it is quite evident that the above scaled total capital investments are comparable to gasify coal or pyrolyze municipal refuse and then synthesize methanol from the gases. As was noted previously, the economics of scale are evident as the small capacity Seattle (Purox)[19] process for converting municipal solid waste to methanol cannot compete economically with a coal conversion plant an order of magnitude larger even at a zero cost for waste feed stock.

Since the above indicates that the capital investments are comparable to convert coal or cellulosic waste to methanol when the input energies are equal, the principal differences in cost of the methanol produced should lie with the operating costs and the costs of the input material. If this can be substantiated by a more detailed analysis, then it should be possible to rapidly evaluate the costs using any other feedstock containing carbon and hydrogen. This of course presumes that these processes for gasifying or pyrolyzing feedstock will in fact function with other materials to be considered. In general, using municipal solid waste as source material is probably the most unfavorable feedstock owing to the presence of non-cellulosic foreign materials. The use of wood, agricultural waste, peat, etc. appears to offer fewer difficulties.

FOREST PRODUCTS COSTS

The cost to source methanol from forest products is difficult to obtain at present. In general the Union Carbide Purox system for municipal waste is the preferred route although not necessarily the reactor one would design for wood and wood chips. The State of Maine Office of Energy[67] Resources has studied the conversion of wood and wood waste to methanol and finds that 40% yields of methanol can be achieved in the laboratory with a possible 30% yield in the field. The costs calculated for the production of synthetic fuels from wood appear to be approximately those estimated for producing methanol from coal. However at this stage it is unknown as to what capital cost savings are inherent in having a wood based plant.

Among the major unknowns in utilizing wood and wood waste as a source material is the cost of harvesting and transporting the material to a plant. Investigators in Maine[112] have studied this problem and have calculated that by selective cutting using manual harvesting methods and private roads a cord of softwood pulp can be delivered 50 miles for \$39.75 per cord (1975 dollars). This is a cost of \$18.50 per ton. (1 cord of softwood weighs 2.15 tons.)

The breakdown by item of this cost is as follows:

Cutting	\$8.00
Skidder (incl. equipment & man)	4.00
Saw	1.00
Taxes, Workman's compensation	2.00
Trucking	8.00
Stumpage	8.00
Access	2.00
Road Maintenance	1.50
Overhead	2.50
Camps	.75
Profit	2.00
	\$39.75 per cord (\$18.50 per ton)

If a machine harvester is used to bring out the same ton 50 miles the cost is calculated at $12.07 per ton. The breakdown of this cost is as follows:

Equipment	$1.38
Trucking	2.41
Stumpage	3.72
Labor	1.14
Fuel	.26
Access	.95
Road Maintenance	.70
Camps	.35
Overhead	1.16
	$12.07 per ton

These costs could vary by ±25% as regards both geography and time. It also should be noted that in Maine this equipment is being used only 9 months of the year. This type of mechanical system has a capacity of harvesting and chipping 250 tons per day.

If the Uni .. Carbide Purox system is applicable to convert wood chips to methanol, the capital investment cost should be $56 million for a system capable of handling an input of 15 billion BTU per day (1000 tons of wood) as described above. If comparable operating costs of $6.1 million per year are assumed, then the difference in cost between the municipal waste and wood as feedstock is simply one of cost and process yield. The annual quantity of wood for this size system would be 365,000 tons which at a cost of $12.07 per ton is $4.4 million. The total annual cost for a 1000 tons per day wood fueled system producing 285 tons of methanol per day is

1000 TONS PER DAY WOOD INPUT

$8.4 million	15% of Tot. Capital Investment of $56 million
6.1 million	Annual Operating Cost
4.4 million	Annual Wood Cost
$18.9 million	TOTAL Annual Cost

This is a cost of $9.10 per million BTU of methanol. ($1.38 per gallon.)

If this wood-to-methanol system were scaled using the 0.6 power of capacity scaling convention for plant investment, the total annual cost for a plant comparable in size to each of the two AEC plants above producing 5000 tons of methanol per day would be:

$$\text{Scaling factor} = (2.37 \times 10^{11}/15 \times 10^{9})^{0.6} = 5.25$$

15,700 TONS PER DAY WOOD INPUT

$44.0 million	Capital Investment
96.0 million	Annual Operating Cost
69.5 million	Annual Wood Cost
$209.5 million	TOTAL Annual Cost

This is a cost of $6.40 per million BTU of methanol. ($0.98 per gallon.)

It is difficult at this stage to assess the comparative costs between methanol systems using various source materials. However the above calculation is conservative in that a direct scale up of operating costs by a factor of 15.7 was used. This is clearly excessive since there would be economics of scale in operating costs as well as in investment costs. The wood fuel cost was scaled by 15.7 since the source material would vary directly with plant capacity.

The annual requirements of 5,700,000 tons of wood and wood waste can be readily met in an area such as Maine. (See Table VI). The costs listed above for harvesting and transporting wood over 50 miles are applicable as an area surrounding a plant of this size with a 50 mile radius would contain 1.3 million acres. This area should be sufficient to supply the major part of the plant's requirements.

A more complex cost problem is that related to forecasting the price of energy materials such as coal, wood, agricultural waste, petroleum, etc. as demand increases in the forthcoming years. The major advantage enjoyed by wood is that it is a renewable resource whose growth can be improved by scientific management.

OFFSHORE FLARE GAS COSTS

The 4 trillion cubic feet of natural gas estimated as being vented and flared in the Middle East and North Africa offers great potential as a source material if it can be economically delivered into the U.S. The two major avenues of exploiting this resource are liquifying the gas (LNG) at the well and transporting it in refrigerated bulk carriers or converting it to methanol and bringing it in conventional tankers to U.S. ports. The cost advantage of LNG versus methanol rests heavily on the shipping distance. Studies which compare the two alternatives conclude that the longer the shipping distance and the cheaper the waste natural gas, the more favorable are the economics for methanol. Investigations have shown that for shipment from the Persian Gulf the two processes have comparable economics when natural gas is available at 50 cents per million BTU. For more expensive gas the economics favor LNG and for less expensive gas methanol is the preferred alternative. Estimates of the gas price have generally been in the neighborhood of 10 cents per million BTU in the Persian Gulf. For methanol delivered to the U.S. Gulf Coast it has been estimated[1] that a price of \$1.15 to \$1.25 per million BTU could be expected. (7.5 to 8.0 cents per gallon.) Although the prospects for inexpensive methanol from abroad appear attractive, to date little beyond the planning stage has occurred.[104]

The potential use for methanol production of the natural gas being vented and flared offshore U.S. rests not only on the economics but also on present regulations requiring that flaring be terminated. Although technically feasible to construct an offshore methanol plant with mobility capability, the economics of this alternative compared to a pipeline network will depend greatly on the quantity of the gas available and its distance offshore. In view of the approaching offshore drilling programs, an early analysis of this option cannot be avoided. The annual value, for example, of all the gas being produced in the Gulf of Mexico is rapidly approaching \$3 billion evaluated at \$1 per 1000 cubic feet. The 2% being vented and flared is of the order of \$57 million based on the same value per 1000 cubic feet. Since this \$57 million per year is currently being lost to the atmosphere, the problem is one of deciding how much the country is willing to spend to recover a source of energy of this value presently being lost each year.

FEEDLOT COSTS

The economics of computing cattle manure conversion to methanol were dictated by the existing concentrations of cattle in feedlots. The upper limits as mentioned earlier were 750,000 head with as many as 600,000 head concentrated in a 15 mile radius. A more realistic figure representative of this industry is of the order of 200,000 which would provide approximately 1,200 tons per day to a processing plant on a 330 day per year basis. (90% plant service factor.)

Since investigators[48] have had difficulty in assigning a cost to this raw material, evaluations in general have assigned a zero value to the cost of manure at the feedlot and employ only the cost of transportation in the raw material cost. These costs of course depend upon both distance and volume of material. The available information indicated that a potential plant site should be at no greater radius than 50 miles from the sources of wastes.

Based on an assumption of truck transportation of $0.05 per ton mile and an average haul of 20 miles an average charge of $1.00 per ton is calculated. This rate is reasonable for a high volume short distance trucking. For a plant size of 1100 tons per day input which is capable of gasifying the manure to a synthesis gas to be used for producing methanol, it has been calculated[47,48] that a total capital investment of $2,686,000 including $1,593,000 direct plant cost would be required. The annual operating costs for the plant exclusive of raw material would be $852,000 and the raw material costs would be $360,000 delivered to the plant.

This gasifying process is estimated[46, 47] to yield 8 million SCF per day (166 tons/day) at a cost of approximately \$0.46 per thousand cubic feet of gas. At this stage the cost to synthesize methanol from this gas awaits further detailed information on the process and yields.

ENVIRONMENTAL IMPACT

The utilization of methanol as an alternative fuel for gasoline will require a thorough analysis of the environmental implications of the products of combustion and emission gases as well as the ecological impact of the large scale mining operations required. To date, the in-situ coal gasification programs have yet to be demonstrated to be feasible, although the current work is encouraging. The fracturing of coal and the maintenance and control of the combustion still require additional development. Since both coal (and oil shale) use large mining operations that clearly affect the areas negatively, it is necessary to develop programs for restoring the areas environmentally. Such programs can take the form of using a percentage of the revenue derived from the resource to restore the area. For example, in the western states a 60 foot seam of coal will yield approximately 100, 000 tons per acre. At one cent per ton assessment for reclamation there would be available $1, 000 per acre to restore the terrain. Alternatives to such a system would, for example, be the development of surface mining systems that would simultaneously couple extraction and reclamation processes and the combustion of coal and oil shale in-situ. In order to achieve satisfactory alternative fuels from coal and/or shale it is estimated that the country's mining capacity will have to triple in the next 25 years.

Laboratory tests as well as limited field evaluations have revealed that an auto fueled with methanol has considerably lower emissions than a similar car operated with gasoline. Based on analyses of HC, CO, and aldehyde emissions and on the rate of formation of NO_2 from NO, it appears that the reactivity of the exhaust from a methanol-fueled auto is, in fact, lower than for gasoline. However, until more extensive tests are conducted it is premature to describe quantitatively the extent to which improved exhaust emission may be possible. Some of the more obvious explanations for lower emissions are the lower combustion temperatures which reduces the rate of formation of NO and the higher flame speed of methanol which permits retarding the spark.

The various investigations that have recently been conducted do not permit a precise side-by-side comparison. However in the interest of identifying some of the reported results a partial compilation of some emission products measured has been made.

Tabulated below are the results of a number of tests that have been conducted in various universities and industries to measure NO_x in auto emissions. Although these results are not conclusive there does appear to be evidence of a build-up of NO_x when the operation is richer than stoichiometric and a decrease of NO_x when leaner. The results indicate the need for more comprehensive fuel and engine studies in this area as regards not only NO_x but also CO, HC, and aldehyde emissions. The latter may prove to be particularly significant in the combustion turbine engine.

NO_x EMISSIONS WITH METHANOL AND GASOLINE
(grams/mile)

EXXON	SANTA CLARA	ARB	CONOCO	VW	STANFORD
6.4 g/mi[a] (gasoline)	0.67 g/mi[d]	1.30 g/mi[f]	4.0 - 10.0 g/mi[g] (gasoline, max power)	2800 ppm[i] (gasoline)	1.07 g/mi[k]
8.1 g/mi[a] (blend)			2.2 - 1.8 g/mi[g] (methanol, max power)	2200 ppm[i] (methanol)	
2.6 g/mi[b] (gasoline)	0.282 g/mi[e]		.8 - 8.0 g/mi[h] (gasoline, road load)	4400 ppm[j] (gasoline)	
2.3 g/mi[b] (blend)			.2 - 1.8 g/mi[h] (methanol, road load)	2500 ppm[j] (methanol)	
2.6 g/mi[c] (gasoline)					
1.7 g.mi[c] (blend)					

VW values are in parts per million

ARB - Air Resources Board

CONOCO - Continental Oil Company

a 1967 auto, blend is 15% methanol and 85% gasoline, air-fuel ratio is slightly rich

b 1973 auto, blend is 15% methanol and 85% gasoline, air-fuel ratio is approximately stoichiometric

c Advanced model auto, blend is 15% methanol and 85% gasoline, air-fuel ratio is approximately stoichiometric

d 1972 Plymouth Valiant tuned for best emission performance

e 1970 Gremlin in 1974 Reduced Emission Devices contest - Santa Clara University

f Air Resources Board test on Santa Clara University auto

g 1973 Ford, for a range of speeds 30 to 70 miles per hour

h 1973 Ford, for a range of speeds 30 to 70 miles per hour

i Single cylinder engine with compression ratio of 8.5, air-fuel is stoichiometric, Volkswagen tests

j 4-cylinder engine with compression ratio of 8.5 operating at 3000 rpm.

k 1970 Gremlin in 1972 Reduced Emission Devices contest - Stanford University

SOCIOLOGIC-ECONOMIC IMPACT

The current market at retail levels for the annual 100 billion gallons of gasoline fuel consumed in U.S. is in excess of $30 billion per year. Investment in the chemical process industry formerly required one dollar in investment for each dollar in sales. Consequently the U.S. gasoline business represents an investment of over $30 billion. The development of an alternative fuel economy that would dislocate this business to any extent would produce severe financial problems. Current production of methanol is one billion gallons per year valued at a current market price of $380 million. In order to add, for example, only 2% methanol to gasoline would require an investment in facilities approximately $560 million. Correspondingly gasoline production facilities of 1 billion gallon capacity would be utilized less. The economic and social impact of adding and changing the utilization of one of the nation's major industries would have to be thoroughly studied.

Since the location of methanol production facilities may be in the area of the source of coal, shale, or forest products, there will be major problems of shifting populations into regions which are not prepared for major increases in population. Concurrently sufficient people must be found with the skills, or, who can be trained to handle equipment of this type. Finally the production of mechanical mining and earthmoving equipment is limited by virtue of the few companies producing large scale off-highway trucks, grader, scrapers, and loaders. In recent years as many as 40% of these vehicles have been for the export market. A particularly severe limitation in this regard is the production of draglines for excavating since the number of manufacturers are few and individually they are of relatively small size. As regards off-highway trucks, in 1972 for those of greater than 45 ton capacity such as are used to transport materials in mining, construction, petroleum developments, and similar projects approximately 40% ($31,000,000) were exported of a total of $83,000,000 produced that year.[40]

It is estimated that 50% of the U.S. coal reserves are located on public lands. These include lands under the supervision of the Bureau of Land Management, the Forest Service, or the Bureau of Indian Affairs. Since the siting of a plant and selecting a coal source are critical to the success of the total program it is necessary to resolve any inherent problems such as those associated with Indian populations that may at present inhabit the areas. These problems may not only consist of physically disrupting the land but may also involve the utilization of other resources such as water, or the diverting of water, which had already been scheduled for other uses such as farming. It will be necessary for all competitive sites in each coal producing region to be evaluated from a socio-political acceptability standpoint and potential for commercialization in order to select the optimum site.

TOXICITY AND FIRE HAZARDS

The hazards and toxic effects from concentrated hydrocarbons is well known. While these organic substances vary as to their effect, in the vapor state they are generally poisonous and as liquids are equally so if taken internally.

Methanol is a Class 1B flammable liquid as defined by the National Fire Protection Association (NFPA) and U.S. Occupations Safety and Health Standards and has been handled safely for many years.[16,17] As a fire hazard the limits of flammability of the vapor of methanol in air are broad compared to gasoline. Liquid methanol must be kept away from heat, sparks, and open flame and when stored or handled should be adequately ventilated. Chemicals in any form can be safely stored, handled or used if the physical, chemical and hazardous properties are fully understood and the necessary precautions, including the use of proper safeguards and personal protective equipment are observed.

The Manufacturing Chemists Association[36] have developed comprehensive procedures and instructions for the safe handling and use of methanol. This material delineates the hazards and the engineering control of such hazards; employee education and training policies and procedures together with personal protective equipment instructions; instructions for fire-fighting and equipment to be employed; the handling, storage, and unloading of methanol; the labeling of storage containers to conform with the Federal Hazardous Substances Labeling Act and similar state and municipal regulations, statutes, and ordinances; the cleaning of equipment and waste disposal; and the toxic effects and preventive measures.

Serious poisoning will rarely be encountered with methanol in circumstances other than from oral ingestion. However in circumstances of heavy exposure by inhalation or skin contact medical attention should be sought at once. Inhalation exposure of one to two hours at concentrations in the order of 50,000 parts per million can be fatal. Precautionary measures should be taken to maintain concentrations at levels not exceeding 200 ppm although the American National Standards Institute[38] has established an acceptable ceiling concentration of 600 ppm with an acceptable peak for a 30 minute exposure of 1000 ppm.

INTERNATIONAL AND POLITICAL IMPACT

The United States has been a net exporter of methanol notwithstanding the approximately 5 to 10 million gallons frequently imported in a year.[11] Tariff restrictions in recent years have limited imports but more recently these have been lifted for specific applications.[95]

In view of the existing petroleum situation it would be expected that imports would decline rapidly as the producing countries utilize the production in their local markets. Furthermore since most heavily industrialized countries are large consumers of petroleum as well as methanol, such countries as Japan, Italy and Canada who formerly exported to the United States would now compete for methanol in the world market as importers. Japan's production of methanol in 1969 was estimated to be of the order of 274 million gallons which is close to 30% of the U.S. production. This would rank that country as the world's second largest[11] producer. Japan's consumption is forecast to exceed 500 million gallons in 1975.

A major difficulty in assessing the European supply and demand situation (and hence the price) is the existence in the Soviet Union of the capability to shift plant production from methanol to ammonia. In the past when these Soviet plants were scheduled to produce methanol there had been as much as 60 million gallons of methanol available for export. On the other hand when production was concentrated on ammonia for fertilizer, there was no methanol for export.

U.S. has for years exported methanol to all parts of the free world. In 1969 exports totaled over 100,000,000 lbs. (16,000,000 gallons). Among the major countries to which shipments were made in that year were, in order of size, Mexico, Brazil, Australia, Colombia, Philippines, Venezuela, Canada, Germany, and South Africa.[11] This export market is generally unstable and depends upon the amount of excess capacity over demand in this country and in other exporting countries, the number of new plants installed in less developed countries, and the policy of the Eastern European countries toward methanol. As mentioned earlier Japan and the Soviet Union are major contributors to this instability. In order for the U.S. to move in the direction of a methanol-fueled economy with consequent large increases in U.S. production, it may be necessary to make changes in the tariffs since an international methanol surplus could readily result. If any of the Middle East countries decide to construct production facilities, the problem of surplus would be compounded.

POLITICAL AND ECONOMIC IMPACT

At present tax rates, a 30% reduction in the consumption of automotive fuel for transportation will produce a $3 billion decrease in the Federal Highway Administration revenues. This is equal to 1% of the total annual U.S. budget. The political and financial impact of reducing the use of gasoline and associated tax revenues will have to be thoroughly considered in weighing the implications of introducing an alternative fuel. Furthermore, if the government makes a committment to financially assist in developing large methanol from coal facilities, it will be competing for money which in turn will force interest rates higher producing higher costs of construction.

INTRODUCTION OF METHANOL INTO THE MARKET

The introduction of methanol into the automotive market will require an approach considerably different from that for public utilities. The latter are relatively few in number and are technically proficient and equipped to evaluate alternative fuels and make the decision to utilize a specific fuel providing the operating performance is satisfactory, the economics are acceptable, and it can be supplied and stored in sufficient quantities on a timely basis.

On the other hand the automotive market is one in which customer acceptance must be gained through price, availability, and proven performance. There is not an overly developed feeling of brand loyalty among car owners and at times when gasoline is in short supply any such loyalty disappears. However, where a shift from gasoline to a completely "new" fuel such as methanol is being stressed, there must be some inducement for the consumer to use methanol if gasoline is simultaneously available. Since an incubation period is going to be necessary before acceptance is achieved in any degree, the early introduction of methanol or a gasoline-methanol blend at the service station pumps is desirable. In view of the quantities of methanol now being produced from natural gas, there should be made available some of this production in order to begin introducing methanol to the consumer. An alternative course of action opens if methanol imports were to increase by virtue of European capacity or Soviet Union capacity increases or the addition of new plant facilities in the Middle East oil fields. This additional source could provide methanol for the transition period until methanol-from-coal was available.

To accelerate the introduction, state or federal government inducement and assistance would aid considerably. California is currently considering legislative action which would require the introduction of methanol-[113] gasoline blends by 1980 for vehicle use in the state. It may be necessary also to underwrite a part of the financial investment involved if the early methanol plants costs are too costly for private enterprise. Such assistance may take the form of reduced federal taxes on methanol used for transportaion purposes or for public utility fuel. In any case notwithstanding the introductory difficulties, government aid will be needed in order to provide price support for methanol in the event the price of foreign crude oil is reduced with a resulting drop in gasoline prices in the U.S. Industry is particularly reluctant to embark on a program involving major commitments of personnel and funds if there is an obvious risk such as that existing in international oil prices. Some studies have concluded that a substantial commitment is necessary by the federal government in order to assure success in this area. Such commitments should include: organizing allocation programs where needed for resources, manpower, and equipment; removing institutional roadblocks in the production and use of energy resources; devising policies for related action by all branches of the government; devising financial incentives where needed; and supporting research and development when risks are too great for private investors.

PUBLIC UTILITY COMBUSTION TURBINE DEMONSTRATION

The specific program that is needed first is to launch methanol as an alternative fuel to distillate for the combustion turbines in public utility electric generating plants. This will require a demonstration to the electric power industry of a combustion turbine operating under load for a time period sufficient to conclusively show the favorable performance and characteristics of methanol as well as to uncover any unforeseen problems not revealed in laboratory tests.

This field program should be a joint effort of a public utility, combustion turbine manufacturer, producer of methanol, a sponsor and ERDA. The machine will need to be converted for methanol combustion. This will involve some minor modifications in fuel pumps, fuel flow systems, combustion liners, manifolds, as well as some fuel additives to improve lubricity of the methanol and explosion proofing of the unit. This conversion should be performed by the turbine manufacturer. A demonstration is desirable with a relatively new machine sufficiently large to scale the test results to a much larger turbine. A 20 or 30 megawatt unit appears to be satisfactory for this purpose. It is expected that a dual fuel unit which can burn natural gas is needed for starting purposes. Emission products will need to be monitored and measured for various air-fuel ratios and consequently a simple cycle machine would permit this to be accomplished more readily. The validity and integrity of the measurements of the products of combustion are important and should if possible be performed by an independent laboratory.

A 20 megawatt machine burns 4,000 gallons/hour of methanol. For a 500 hour test approximately 2,000,000 gallons will be consumed. However, since this will be a test in which electricity is generated and sold, the net fuel cost of the demonstration is the differential cost between distillate and methanol at the time the test is conducted.

The total daily production of methanol in the U.S. is 3,000,000 gallons. With the current slump in methanol sales owing to reduced construction in the nation, there are chemical manufacturers holding inventories as high as 12,000,000 gallons. Consequently the current period is excellent for conducting the test. A planned schedule should be developed, as soon as a public utility has agreed to conduct the test on one of its combustion turbines, to secure and store the methanol needed for the test. The most likely source of large quantities of methanol is the Gulf Coast which means that movement of the methanol will probably be by tanker or barge to a tank farm in the general area of the utility. Concurrently a commitment should be secured from the gas turbine manufacturer, who agrees to participate, as to his planned schedule of modifications for the demonstration unit.

Widespread publicity of the demonstration should be made to the public utility industry as to the first large scale demonstration of a synthetic fuel on an operational basis.

AUTOMOTIVE DEMONSTRATION

There has to date been published in the literature considerable amounts of fragmentary data on using methanol and methanol blends as fuel in autos. Much of this work although limited experimentally has been encouraging. A series of definitive tests should now be considered to verify the widespread applicability of this fuel by undertaking a large field program involving fleets of vehicles to supply statistically meaningful performance and operating data.[129]

This vehicle test program should involve the selection of vehicle fleets utilizing either local government, municipal, or agency vehicle pools who have controlled operation and maintenance of their vehicles as well as limited geographical areas in which they operate.

The development of programs to evaluate various blends as well as pure methanol is essential. This would include obtaining data on such factors as carburetor settings, moisture levels in fuel, driver reaction, leaks and spillage, carbon monoxide and oxides of nitrogen and hydrocarbon emissions.

The fleet testing should be conducted for at least 1 year in order to secure performance through various seasons as well as wet and dry weather. Concurrently a laboratory test program should be conducted to support the field program. The goal of this work would be to obtain engine performance and emission information under controlled conditions and with specific fuel blends for the purpose of eventually being able to optimize the engines for methanol. A part of this program will be fuel studies to further enlarge knowledge of phase stability, material compatibility, handling and storage and distribution practices, additives, and other physical and chemical characteristics.

The need for continuous publicity as regards this fleet testing is vital in order to keep methanol before the public. Publicity should be focused on the sourcing in the near future of this fuel not from petroleum sources but instead from coal, municipal waste and trash, and forest products in the U.S.

Vigorous stimulation of the federal government to embark on a number of methanol-from-coal, methanol-from-waste, and methanol-from-forest products programs should be undertaken. Early introduction of methanol-gasoline blends should be aggressively pushed within the framework of any constraints growing out of the laboratory and fleet test programs. The assistance of federal, state, and local authorities and legislative bodies should be enlisted to further this goal through proposed legislation and planned energy programs.

A most encouraging conclusion growing out of this analysis is the recognition that the U.S. forests offer an excellent solution to one of the country's energy problems. Logging and mill wastes alone if converted to methanol using a 30% efficient process are sufficient to produce annually 11.5 billion gallons of methanol. This is equal to 5.7% of the total annual consumption of gasoline in the nation. Further, the State of Maine, Office of Energy Resources, study on wood reveals that the principal thrust of U.S. energy development should be in the direction of scientific management and development of forest resources. Their field studies show that from Maine's 17.7 million acres of forests there is the potential to remove with the aid of good methods and practices waste and undesirable growth in sufficient quantities to also produce 11.5 billion gallons of methanol each year within the state.

A similar study conducted in California's north coastal region in a limited area found that 1 million tons of wood waste were being created annually and constituted an excellent and large source of raw material for converting to methanol as a fuel supplement.

APPENDIX I

In making estimates of energy resources of petroleum, natural gas, natural gas liquids, coal and other U.S. minerals, it becomes necessary to differentiate between deposits that (a.) are known and have been carefully evaluated, (b.) those that are known to exist but have not been measured, and (c.) those believed to exist based on geologic information but the precise location of which is unknown. Further, in order for the resource to be usable the deposits must be accessible. Consequently estimates must be such that the resources can be categorized based on current technical and economic capability for extraction.

A classification[58] of resources which provides reasonably well-defined categories is as follows:

a. Known recoverable reserves are deposits whose size and location have been determined. Furthermore they can be extracted or recovered by means of current engineering technologies on an economically acceptable basis.

Such terms as proved and inferred of the American Petroleum Institute and measured economic resources of the Department of the Interior are essentially equivalent to this category.

b. Undiscovered recoverable deposits are those that can be extracted economically with the present technology; however their specific location is unknown but is indicated by geological information.

c. Known marginal and submarginal deposits are those whose size and location are known but cannot be extracted either until improvements in the extraction technology occur, or, until economic conditions change.

d. Undiscovered marginal and submarginal resources are those whose presence and size are indicated by geological information but neither the specific location is known nor can extraction take place until the technology advances or the economics become more favorable.

On April 15, 1974 the Department of the Interior issued a news release defining mineral resources terminology which differs from that generally used by American Petroleum Institute and the oil industry. It was planned that U.S. Bureau of Mines and the Geological Survey would henceforth adopt this terminology. Currently it is understood that members of the oil industry and the American Petroleum Institute have preferred to continue with API defined terms.

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10/23/75

A Brief Review of the Multistate Tax Compact

A) What the Compact Does

Basically, the Compact provides a means which has not been available in the past to enforce a state's corporate income tax laws. By providing for a general uniformity between the tax laws and regulations of the member states, corporations (and other multistate taxpayers) can be forced to provide the same income reports to all of the states. This makes it possible for states to pool their auditing resources and more carefully check the accuracy and consistency of multistate taxpayer reports. This basic uniformity also helps avoid disputes based on charges of double taxation, charges which could develope if every state's tax laws were significantly different. If disputes as to the proper allocation of incomes do arise, a method of arbitration is provided by the Compact. What the Compact does not do is depart any significant way from past policy in the treatment of multistate corporations. Thus the Compact is basically an agreement between states to ensure the effective and fair taxation of multistate businesses.

B) The Economic And Financial Effects Of The Compact

The Compact has two significant characteristics which a state by itself does not have. First, the enforcement capabilities of the Compact provide a tool by which states can approach a greater equity in the treatment of interstate and intrastate businesses. Without the Compact

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it is possible for some multistate corporations to shift their net incomes to non- or low-tax states, something that one-state businesses can not do. Second, the basically uniform allocation of a corporation's income between states combined with the arbitration mechanism reduces the possibility of significant double taxation to its practical minimum. This eliminates the claim that multistate taxpayers should have special (lower) tax treatment due to the double taxation possiblity, and allows the state to tax at whatever rate it deems reasonable.

C) The Allocation Formula

The advantages of enforceability and equity are bought at the price of basic uniformity in the allocation formulas and regulations of the member states. Although the details of the formula may be shaped by each state, the basic formula which all member states must use is given in Article IV, Sec. 9 of the Compact. The following is a discussion of the three factor formula of property, payroll, and sales, as it relates to Alaska.

1) The Property Factor: This factor, according to the Multistate Tax Compact, Article IV,10 includes, "... the average value of the taxpayer's real and tangible personal property owned or rented and used in this state during the tax period." The Alaska Administrative Code, 15AAC10.120(a) states that the property factor numerator "...shall include the average value of the taxpayer's real and tangible personal property in this state during the tax period used, is available for use, or is capable of being used for the production of business income." For most businesses the above definitions are adequate, however, they do not clearly include mineral reserves in the property factor of extractive industries. Although they imply that reserves may be included, it is suggested that

the phrasing adopted by the Multistate Tax Commission, Feb. 13, 1973, be included in the updated revenue code (to be proposed by the Dept of Revenue in the near future) as follows: "Property held as reserves or standby facilities or property held as a reserve source of material shall be included in the factor. For example, a plant temporarily idle or raw material reserves not currently being processed are includable in the factor" (Commission Reg. IV. 10.(b),).

This would remove any doubt concerning the inclusion of oil, gas, and mineral reserves in the property factor of extractive industries. With the clear inclusion of mineral reserves in the property factor of multi-state taxpayers, the property factor should fairly reflect the property interests of a business in this state. (Note: The Alaska Code might also specifically state by what method mineral reserves will be valued, e.g. the same method as for ad valorem tax purposes. This might help avoid debate as to what valuation of reserves should be used.)

2) The Payroll Factor: Fortunately for Alaska, this factor is based upon the "total compensation paid" to the taxpayer's employees rather than the number of employees paid by the taxpayer. Thus, the higher salaries paid in Alaska will be reflected in a high portion of the payroll factor being allocated to Alaska than if a simple head count were used. This is economically justified by the fact that government services are also made more expensive than in other states. No significant changes to the payroll factor appear to be needed.

3) The Sales Factor: According to the Multistate Compact, both sales which occur in the state and sales which are predominantly due to "income

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producing activity" in the state are allocated to the state (Article IV. 15 and IV.17.((a)(b).). The Administrative Code, 15AAC 10.280., defines an "income producing activity" as "the act or acts directly engaged in by the taxpayer for the ultimate purpose of obtaining gains or profit." The major exclusion from this allocation rule is "income producing activity" performed by an independent contractor. Such activity is not included in the sales factor because the contractor pays the income tax on that activity. For most business activities in the state this is a fair and reasonable method for the allocation of gross sales. The complex contractual arrangements between the several large pertroleum corporations active in the state (and their vertical integration) make the allocation of their sales and "income producing activities" more difficult to determine. It is clear that the Multistate Tax Compact is referring to just the type of activity which extractive industries are pursuing in Alaska when it refers to "income producing activities." It is suggested that the Alaska Administrative Code for Revenue contain specific reference to the extractive industries and examples of how sales from their "income producing activity" should be allocated to Alaska.

4) The Adjustment Provision. This provision allows for unique situations which may arise in relation to specific states or businesses. Article IV. 18. of the Compact states:

> If the allocation and apportionment provisions of this Article do not fairly represent the extent of the taxpayer's business activity in this state, the taxpayer may petition for or the tax administrator may require, in respect to all or any part of the taxpayer's business activity, if reasonable:
> (a) separate accounting:
> (b) the exclusion of any or more of the factors;
> (c) the inclusion of one or more additional factors which will fairly represent the taxpayer's business activity in this state; or

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(d) the employment of any other method to effectuate an equitable allocation and apportionment of the taxpayer's income.

Thus, in special cases (e.g. the sales factor for a vertically integrated industry cannot be made to reflect the industry's actual activity in the state) the adjustments can be made without affecting the Compact or allocation formulas in general. Such adjustments must be made only with very good reason and with great care, because their "reasonableness" may be challenged in the courts or during arbitration. The general uniformity of the Compact, however, is not a straight jacket.

D) Preliminary Results From Compact Membership

Although the Multistate Tax Compact did not go into effect in Alaska until July 1, 1970, and the current Administrative Code relating to the Compact did not go into effect until July, 1972, some tentative obesrvations can be made. In 1970-71, the first year under the Compact, and in 1973-74, the first year in which extensive enforcement of the Compact allocation was implemented, corporate income tax revenues jumped 14.41 and 18.34 percent respectively over previous years. This compares with growth rates of 6.48 and 7.84 percent in fiscal years 1970 and 1971 respectively (Figures from "Revenue Projection Detail", 12/19/74). It is not clear just what portion of the greater increases in fiscal years 1971 and 1974 were merely due to surges in economic growth in Alaska, but it is possible that part of the extra growth in tax collections was due to the Compact and its enforcement. A more concrete example of the Compact's value is seen in the additional corporate income tax billings being sent to five or six major multistate (oil) corporations. These are based on Department of Revenue audits which the provisions of the Compact facilitate. Two of these billings are for well over one million dollars each, totalling approximately three million. The final amounts of the other billings

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have not yet been determined. Note that this compares with the $134,860 originally paid by 3 of the 10 oil producers operating in the state in fiscal year 1973 (April 17, 1975 memo by Kathy Hollier, Research Analyst, Department of Revenue). In addition to these billings, the state has already received over $150,000 and has approximately $2.5 million in pending assessments due from other multistate taxpayers' operations in Alaska. Thus, preliminary evidence indicates that the Compact is assisting the Department of Revenue in obtaining significant increases in corporation net income tax revenues. As Alaska's Administrative Code for the Compact is fine tuned to Alaska's needs, it is probable that the Compact will be even more helpful in the future.

E) Alternatives To The Compact

It is possible that the State could choose to develop its own tax allocation formulas and regulations independent from other states. The object of such an independent approach would be to allocate a greater share of multistate taxpayers' incomes to the state than is possible under the Compact. There are three major problems with this approach. First, if Alaska's corporate income tax varies in major ways from other states, Alaska would have to enforce the tax without the close assistance of other states. If past experience is any guide, the state would likely loose money rather than gain it. Second, if the formula caused the tax burden of multistate tax-payers to be significantly higher that intrastate taxpayers, the long term economic effect would be to discourage new investment in the state. Such a possibility should be considered carefully in view of the state's current employement situation. Third, and perhaps most important, all of the legal battles concerning the legal standing and equity of the new tax approach would have to be fought. These battles have largely been fought and won for the basic formula and approach used in the Multistate Tax Compact. Thus, for enforcement, economic equity, and legal reasons, such an independent course would be difficult to pursue.

It might be suggested that the state withdraw from the Compact but maintain the basic tax approach of the Uniform Division of Income for Tax Purposes Act (UDITPA - the basis of the Compact). This would gain the state nothing in the way of really new tax options while weakening its enforcement ties with other states. Such an approach would seem to the worst of both worlds.

Finally, the state could remain within the Multistate Tax Compact, refine the state's implementing code, and make any further adjustments needed through the Compact's adjustment provisions. In those industries, specifically extractive industries, which may impose special burdens on the state and/or on future citizens of the state, severance taxes and/or ad valorem taxes could be used to supplement revenues from the net income tax.

F) Conclusion

The Multistate Tax Compact generally appears to be well suited for the needs of Alaska. Preliminary indications are that the Compact is assisting the Department of Revenue in the enforcement of the state's corporate net income tax. The allocation formula lends itself to a basically equitable treatment of both intrastate and interstate taxpayers while allowing for special or unusual cases. If such revenues are considered too low in certain industries, additional separate taxes should be used.

ALASKA
STATE LEGISLATURE

MEMORANDUM

October 20, 1975

TO: Senator John Huber, Chairman

FROM: Terry Berman, Assistant

SUBJECT: October 6, 1975, meeting with Sterling Gallagher, Commissioner of Revenue

The staff met with the Commissioner of Revenue to discuss the multistate tax compact and the severance tax.

Commissioner Gallagher discussed the information collection and processing that was being done with respect to multistate corporations and the changes in administrative procedures regarding collection. He also expressed interest in increasing the severance tax.

This meeting enabled us to begin obtaining needed information from the Department of Revenue.

TITLE: LEGAL ANALYSIS OF THE MULTISTATE TAX COMPACT

file copy

REQUESTED BY: Senator John Huber, Chairman
Committee on Taxation and Revenue

DATE SUBMITTED: 10/16/75

STATEMENT OF FACTS

The Committee on Taxation and Revenue's staff in it initial review of corporate income taxation has put special emphasis on taxation of multistate corporations, under the present Alaska income tax statutes. Alaska is one of forty five (45) states and the District of Columbia which levies an income or franchise tax based on the net incomes of corporations and other similar organizations. Alaska's tax base is tied to the Federal income tax net income figure.

The State of Alaska is a member of the Multistate Tax Compact. The Compact was drafted in 1966 and became effective in 1967 after seven (7) states had adopted it. Alaska became a member on July 1, 1970. The purposes of the Compact are: 1) To facilitate proper determination of State and local tax liability of multistate taxpayers by equitable apportionment of tax bases and, 2) To avoid duplicative taxation.

On this, the initial review of the corporate income statutes, it has been tentatively decided that more revenue can be raised from the multistate corporations by use of the Compact. The method of accomplishing this would be through strict enforcement of the present allocation formula or through changes to the present allocation formula.

Questions Presented

1) Is Alaska's participation in the Compact legal under the United State Constitution?

2) Will the use of an allocation formula on income derived in Interstate commerce run afoul of the Commerce Clause and Fourteenth (14th) Amendment Due Process Clause of the Constitution?

3) Can the income from a subsidiary of a multistate corporation be unitized with the parent corporation for purposes of applying the allocation formula?

Brief Answer

Legality of the Compact

Under the correct interpretation of the U.S. Supreme Court, the Compact is legal. The Compact does not increase the political power of the states.

Use of Allocation Formula

The allocation formula set out in 15 AAC 10, Multistate Tax Compact, only levies taxes on that portion of the taxpayers net income arising from its activities within Alaska. The taxes imposed by the allocation formula are not a direct burden on interstate commerce and do not conflict with the Due Process Clause.

Unitizing Income of Subsidiaries and Parent Corporations

When the operation of business done within the state is dependent upon or contributes to the operation of the business without the state, the operations are unitary. The income from a subsidiary of a multistate corporation can be unitized with the parent corporation.

Applicable Statutes

Article I, Section 10, Clause 3 of U.S. Constitution

No state shall, without the consent of Congress ... enter into any agreement or compact with another state ...

Article I, Section 8, Clause 3 of U.S. Constitution

The Congress shall have power . . . to regulate commerce .. among the several states . . .

Fourteenth Amendment of U.S. Constitution - Due Process Clause

No state shall make or enforce any law . . . nor shall any state deprive any person of the life, liberty, or property,, without due process of law.

AS 43.19.010. Article IV

Article too long to reproduce

15 AAC 10 Multistate Tax Compact.

Compact too long to reproduce

Discussion

Legality of the Compact

Even though the words of the Constitution seem to prohibit all compacts entered into without the consent of Congress, current judicial interpretation limits the all or nothing aspect of the Article. The United States Supreme Court in 1893 laid down the rule in Virginia v. Tennessee, 148 US 503 (1893), 37 LE 537, which states: "...Looking at the clause in which the terms "compact" or "agreement" appear, it is evident that the prohibition is directed to the formation of any combination tending to the increase of political power in the states, which may encroach upon or interfere with the just supremacy of the United States..."

The several states have entered into the Compact as a means of insuring that the states power to tax multistate corporations will not be interfered with by Congressional action. Congress has set some restrictions in Pub Law 82-272 (15 USCS 381) and has made studies. Each session has seen the matter come up, but with the exception of Pub Law 86-272 , nothing has been done.

The Compact does not increase the political power of the states. The states have the power to tax. In entering into the Compact they are facing the economic reality that much of the business in the country is carried out by multistate corporations. In order to derive a fair amount of tax from those corporations, the states have entered into the

Compact to ensure equitable apportionment among themselves and avoidance of duplicative taxation.

Consent of Congress can also be implied. Virginia v. Tennessee supra. Since the Compact's inception in 1967, there has been continuing Congressional action on the matter. That action has not resulted in any legislation approving or disproving the Compact, of which Congress is well aware. "..It seems fair to say that Congress impliedly consents to the existence of any compact of which it has knowledge and has not been negated by legislators..." The Compact meets the test of Constitutionality.

Use of Allocation Formula

The use of the allocation formula has been attacked on the following grounds by the multistate corporations: 1) It is a tax on the privilege of engaging in interstate commerce, 2) It is inherently discriminatory and 3) It results in a multiple tax burden. The first raises an issue under the Commerce Clause and the second and third raises issues under the 14th Amendment Due Process Clause of the U.S. Constitution.

Both issues have been extensively litigated and most decisions have been returned in favor of the allocation formula. A tax that is a direct burden upon the operation or act of interstate commmerce is unconstitutional. The mere act of carrying on business in interstate commmerce does not except a corporation from state taxation.

The U.S. Supreme Court stated in the leading case of Northwest States Portland Cement Co. vs. State of Minnesota, 358 US 450, 3 Led 2d 421, 79 S.Ct. 357: "...We conclude that net income from the interstate operation of a foreign corporation may be subjected to state taxation provided the levy is not discriminatory and is properly apportioned to local activities within the taxing state forming sufficient nexus to support the same..." In the case of General Motors Corp. vs Washington, 377 US 436, 440-441 (1964), the U.S. Supreme Court following Northwest stated this controlling test:

> "...A careful analysis of the cases in this field teaches that the validity of the tax rests upon whether the state is exacting a constitutionally fair demand for that aspect of interstate commerce to which it bears a special relation. For our purposes the decisive issue turns on the operating incidence of the tax. In other words, the question is whether the state has executed its power in proper proportion to appellant's consequent enjoyment of the opportunities and protections which the state has afforded ... As was said in Wisconsin vs J.C.Penny, 311 US 435, 444 (1940), 'the simple but controlling question is whether the state has given anything for which it can ask return'...

The U.S. Supreme Court has sustained the above decisions in Colonial Pipeline Co. vs Treigle, -US-, 44 L Ed 2d 1, 95 S.Ct. -.

Since the taxes imposed are only levied on that portion of the taxpayers net income which arises from its activities within the taxing state, they do not conflict with the Due Process Clause. Northwest supra. The use of an allocation formula that is nondiscriminatory, properly apportioned, and related to local state activity to tax multistate corporations will not run afoul of the Commerce and 14th Amendment Due Process Clauses of the U.S. Constitution.

Unitizing Income of Subsidiaries and Parent Corporations

One of the major problem areas in taxing multistate corporations is where the activities done in the taxing state are carried out by a subsidiary of the parent multistate corporation. This issue has been decided principally in state courts. As noted in the immediate prior discussion, the allocation formula has been upheld.

The general test was stated by the California Supreme Court in Edison California Stores vs McColyes, 30 Cal. 2d 472, 183 P2d 16 (1947). It states "...If the operation of the portion of the business done within the state is dependent upon or contributes to the operation of the business without the state, the operations are unitary ... A more particular statement of the test is that a business is unitary if these circumstances are present: 1) Unity of ownership, 2) Unity of operations as evidenced by central purchasing, advertising, accounting and management division, and 3) Unity of use of its centralized executive force and general system of operations..."

The test was followed in Chase Brass and Copper Co. vs Franchise Tax Board, App. 86 Cal Rptr 350 (1970), dismissed 400 US 961 (1970). Chase was a wholly owned subsidiary of Kennecott Copper Corp. Kennecott did no business in California. Applying the above test, the California Supreme Court found the business between Kennecott and Chase Brass unitary. The same rationale was followed by the Oregon Supreme Court in Coca Cola Co. vs Dept of Revenue, 533 P2d 792 (1975).

Following the lead of the various state courts, the income from a subsidiary of a multistate corporation can be unitized with the parent corporation for purposed of applying the allocation formula. The power to impose the tax on a unitary business flows from the authorized method of determining income from the taxpayers activities within the state, and authority to pursue the method is present whenever activities are partially within and partially without state, whether or not integrel parts of the system are seperately incorporated, or the accounting system of the taxpayer does not clearly reflect the income. Edison California Stores, supra.

Conclusion

From a legal point of view the Multistate Tax Compact is valid under the United States Constitution. Use of an allocation formula that is not discriminatory will forestall any attack under the Commerce and Fourteenth Amendment Due Process Clauses. It is also possible to unitize the income from a subsidiary of the multistate corporation with the parent.

There is an area in which the Multistate Tax Compact is inadequate for the State of Alaska. That area is the taxation of oil and gas revenues.

Only a small amount of tax revenue would be generated if the Compact were used exclusively to get to the multistate oil companies' profits. For taxation of the multistate oil companies another type of tax is needed, ie severance, value added, ad valorem, in addition to the Compact.

Franklin D. Fleeks

Tax Counsel

MEMORANDUM

October 16, 1975

TO: Senator John Huber, Chairman
Committee on Taxation and Revenue

FROM: Franklin D. Fleeks
Committee Tax Counsel

SUBJECT: Value Added Tax

At each of the meeting held, whether formal or informal, the topic of a value-added tax has been discussed. Though all participants had heard of a value-added tax, its concept and operation was not clearly defined. The purpose of this memo is to try to bring clarity to the subject.

History

The value added tax (VAT) is an out growth of multistate turnover taxes used in Europe. The multistate turnover tax was first introduced in Germany during World War I.[1] France adopted the value added tax in 1954. With the formation of the European Common Market (EEC) and its emphasis on harmonizing the various nations taxes, the vehicle chosen was the value-added tax. At present, all of the member states of the EEC have enacted value-added taxes.[2] In the United States, only the state of Michigan had a modified VAT. The modified VAT was repealed when Michigan revamped its law in 1967.[3]

Discussion

Just what is a value-added tax? The simple definitions is that it is a tax on 'value added' by the taxpayer. The most accurate definition found is that VAT is a net turnover tax with prior tax deduction.[4] What must be emphasized is that VAT is a sales tax collected in multistages. "...It is a method of collecting a sales tax that insures that the tax is shifted to the consumer..."[5] As another writer states "...The value-added tax is neutral as to businesses because it does not apply to businesses; rather it is a retail sales tax on the consumers of goods and services and not a tax on the producers or sellers of goods and services..."[6]

The way the tax works is as follows. A producer or seller of goods or services multiplies his total sales by the applicable rate. From this amount, by the tax credit system, the producer or seller subtracts the amount of tax he paid on his purchases and pays the net amount to the government.7

Application of the Tax to Alaska

The question to be asked is: Can a value-added tax increase significantly the revenues from multistate corporations and oil and gas?

Even though the tax has only been used in one state, Michigan, there is nothing in the Federal or State laws that would bar a VAT. Under Article IX, Section 1, of the Alaska Constitution, the State can enact a VAT law.

An Alaskan VAT tax would have one fatal flaw if applied to raise tax revenue from the multistate corporations and oil and gas. That fatal flaw is that the VAT is a sales tax. Under current Supreme Court decisions, Alaska cannot apply a sales tax on goods produced her and sold out of the state. The United States Supreme Court has stated:

> "...The vice of the statue as applied to receipts from interstate sales is that the tax includes in its measure, without apportionment, receipts derived from activities in interstate commerce; and that the exaction is of such a character that if lawful it may in substance be laid to the fullest extent by States in which the goods are sold as well as those in which they are manufactured. Interstate commerce would thus be subjected to the risk of a double tax burden to which intrastate commerce is not exposed, and which the commerce clause forbids..."[8]

In a 1972 New Mexico case where the state levied on proceeds from contracts entered into outside the state with out of state clients, the U.S. Supreme Court in a unanimous decision stated: "...But a tax levied on the gross receipts from sales of tangiable personal property in another state is an impermissible burden on commerce..."[9]

Conclusion

The purpose for which a value-added tax would be enacted is to raise significant tax revenues from multistate corporations and oil and gas.

Because the VAT is a sales tax and under current U.S. Supreme Court decisions the rate cannot be applied to total sales outside Alaska, the VAT would not generate significent additional tax revenues. It is my conclusion that enactment of a VAT tax would serve no useful purpose for the State of Alaska.

Sources

1. Norr and Hornhammer, The Value-Added Tax in Sweden, 70 Columbia Law Review 381 (1970)

2. Gordon T. Butler, The Value-Added Tax; A New $40 Billion Tax For the United States, 50 Texas Law Review 267 (1972)

3. Michigan Complied Laws Annotated, Chapter 206, Income Tax Act of 1967

4. Butler, supra

5. Butler, supra

6. Stanley Surrey, Value-added Tax: The Case Against, 48 Harvard Business Review 77-94, Nov.-Dec. 1970

7. Norr, supra; Butler, supra

8. J.D. Adams Mfg. Co. vs Storen, 304 US 307, 82 L.Ed 1365, 58 S.Ct 913.

9. Evco vs Franklin Jones, 459 US 91, 34 L.Ed 2d 325, 93 S.Ct 349 (1972).

ALASKA STATE LEGISLATURE

MEMORANDUM

10/9/75

TO: Senator John Huber, Chairman
Committee on Taxation and Revenue

FROM: Franklin Fleeks
Tax Counsel

SUBJECT: Notes on meeting with Michael Tanzer, Economist

Persons present:
Michael Tanzer, Consultant
Hugh Malone, Chairman of House Finance Committee
Steve Cowper, Member of Committee on Taxation and Revenue and House Finance Committee
James Rhode, House staff
Norman Baily, House staff
Franklin Fleeks, Senate staff

The purpose in attending the meeting was twofold. The first was to hear what the consultant, Michael Tanzer, had to say. The second was to exchange ideas, cement relations and to determine that the course being set by the House and Senate was parallel.

The following items were discussed at the meeting.:

Discussion with House Representatives

In prior talks with the House staff, it was found that there was not much support for the Multistate Compact. Since this staff had heard only the Administration's side, which was favorable to the Compact, the House staff was asked to state their objections. Their main objection to the Compact is that it is not a good tool to tax the oil and gas revenues coming to the State. The allocation formula is not adequate to

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return to the State its fair share of tax revenue. No objections were voiced to the Compact's validity in taxing other multistate business activity. The House staff as well as this staff believes that the Compact's procedures and enforcement can be strengthened. Both staffs have experienced difficulty in securing hard data on which to base their analysis. It was the consensus that the Agencies have the data but the data is not in an easily accessible form. It was agreed that any data received by the two staffs that might be useful to the other would be shared. This has already been implemented.

The political implications of the proposed tax was also discussed. From the House side it is believed that one large stumbling block will be the Native Regional Corporations. In order to persuade the Native Representatives to go along, it must be anticipated that some form of exemption must be written into the statute. (It must be stressed that this exemption is still very much in the discussion stage.) The type of exemption discussed can be constructed to exclude all Alaskan Corporations and include the multistate corporations.

It was the consensus of the staffs, after this discussion, that we are moving on parallel paths and there is no significant difference in our policies or aims.

Discussion with Michael Tanzer

The meeting with Tanzer was basically to orient him to the situation in Alaska, to let him see the developments himself, to see what additional information he would need, and to set up a timetable for completion of his work. He stated that his basic approach would be the one set out in his August memo. All assumptions will be weighted to the conservative side to forestall any oil industry argument and, if possible, the data used would come from the oil industry. He will use as his period 20 years; from which he will make three computations.

He was asked to explain his idea of an "excess profits tax". He stated that this was just a label, not a concept. Members of the staffs had constitutional problems with the idea of a state "excess profits tax".

The remaining time was spent dealing with the technical details, i.e. how many computations, what type of format, who would provide what, etc. The timetable agreed on was a final report by December 15, 1975, with an interim report submitted for comment.

Conclusions and Recommendations

Dr. Tanzer is qualified to give an analysis of the oil industry. One of the plus factors is that this analysis will be from a point of view that the legislature has not seen. Even with Tanzer's report going to the House members, I would still recommend that our staff, Ed Sterner in particular, make an in-house analysis. The in-house analysis will provide a comparison to Tanzer's analysis and any other analysis that will be submitted.

Miscellaneous

After meeting with Tanzer, I spent the remainder of the time in Fairbanks looking for data from sources known to me personally. Vic Fischer of

ISGER and his editor Ron Crowe were especially helpful, allowing me full access to their files. Other data, consisting of books, prospectus, statistics, etc. were obtained from my personal sources.

October 6, 1975

TO: Senator John Huber, Chairman
Special Committee on Taxation and Revenue

FROM: Franklin D. Fleeks
Committee Counsel

SUBJECT: Alaska Mineral Severance Tax, SB 294.

This memo is a summary of what has happened up to this date on SB 294. It is submitted for your information.

Review of the letters submitted and testimony at the hearing held on May 9, 1975, reveals that mining industry representatives, municipal utility officials, ancillary industry representatives, and interested individuals were unanimously opposed to the tax. The only testimony in favor of the tax was from the Department of Revenue.

The Department of Revenue Position

The Department of Revenue representatives stated that there is a severance tax on all of the state's renewable and non-renewable resources, oil and gas, timber, fishing, etc., except the "hard" mineral industry. The industry, at present, is taxed through a mining license tax, which is a tax on net income. From Commissioner Gallagher's testimony, the hard mineral industry grossed $62,000,000 for the 1974 fiscal year. The sources were as follows:

Sand and Gravel	$42,000,000
Coal	14,000,000
Other	6,000,000
Total	$62,000,000

From the approximately 200 licenses issued only two paid tax. One from the coal industry and one from the platinum industry. The amount collected brought the state $30,000 in revenue. The mining license tax is considered ineffective.

The present law is an additional net income tax. The Department considers it a tax on efficient procedures. Their position is that if a graduated severance tax is imposed it will fall on all producers of hard minerals in the State except those who sever less that $100,000 worth of minerals in a year. SB 294 would serve to tax a non-renewable resource,

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extract revenue from those producers who ship out-of-state or to foreign countries, provide easier administration, and would provide additional revenues from a source that other taxes may not be able to touch. Instead of $30,000 the anticipated revenue is $3,500,000.

SB 294 is considered prospective because of the low level of hard mineral activity in the State. Passage would allow the hard mineral industry to plan rationally its tax cost if further development takes place.

In answer to criticism that the bill was like the British Columbia Royalty tax, the Department of Revenue stated the following. The B.C. bill is a two step royalty linked to international price for the refined mineral and a Canadian wholesale price index. The royalty is in addition to Federal and provincial taxes and cannot be taken as a deduction in computing the taxes. The proposed mineral severance tax would be deductable on Federal and State Income Tax returns, the effect being that the tax would be paid half by the Federal and State governments and half by the taxpayer.

In talking to John Messenger, Assistant Attorney General, it was sensed that it is still the intent of the Department to go forward with the bill. Attempts will be made to make it more palatable.

<u>Mining Industry Position</u>
From testimony and the letters the industry's position is that passage of SB 294 will discourage current and future exploration for minerals. They consider the mineral severance tax a gross receipts tax and as such it is inherently unfair. They also stated that because the proposed tax would add another cost to the already heavy burden of exploring and developing minerals in Alaska, only those prospects having the greatest potential will be exploited. Marginal deposits would be left untouched.

<u>Ancillary Industry Position</u>
Testimony was given by Jim Dotson of the Alaska Air Carriers Association. He represented the view of the air taxi and air charter firms in the State. A large amount of the revenue of his members is derived from providing support to survey teams, geological teams, and others doing the summer exploration work. He had been informed that just because SB 294 had been proposed, two large summer contracts for 1975 had been cancelled. His position was that passage of SB 294 would seriously reduce the air carriers' revenue with a consequent reduction in air service in the State.

<u>Utilities Position</u>
Letters were received from Fairbanks Municipal Utilities System and Golden Valley Electric Corporation, since they are two of the largest consumers of coal for electric generating purposes. Their position is that the proposed tax would be passed on to them and increase their operating costs. This in turn would lead to a rate increase for their customers.

Native Corporations Position

In our Anchorage staff meeting on September 24, 1975, Representative Anderson gave the Native Corporations' position. He stated that SB 294 would make it more difficult to go to the capital market to obtain funds for exploration and development. He also stated that the proposed bill had caused delays in current negotiations with financial institutions.

It should be noted that the Adminstration, by Governor Hammond's letter of May 8, 1975, states that further hearings would be held " . . in order to jointly develop a rational tax . . "

Listed below are the names of the companies and persons who wrote to the Committee.

Mineral Severance Tax Project

Digest of Letters

Date	Correspondent
4/25/75	Dr. Johl Morris
4/17/75	Perry, Knox, Kaufman Inc. M.A. Kaufman
4/30/75	Cominco American J.C. MacLean
4/11/75	Rodney A. Blokestad
4/10/75	U.S. Borax J.E. Stephens
4/18/75	Heflinger Mining & Equipment Company Carl F. Heflinger
4/12/75	Eagle Creek Lodge Don Bennett
4/8/75	GVEA R.L. Hufman
4/4/75	Alaska Miners Association - Fairbanks Branch Mark Ringstad
4/11/75	MUS Robert Hanson
5/5/75	John E. Clark
5/6/75	Ketchkian Pulp Company Edward W. Borger, Sr.
5/6/75	Alaska Gold Company W.A. Glovinovich
5/19/75	C.C. Hawley & Association W.E. Shoemaker

MEMORANDUM

September 23, 1975

TO: Senator John Huber, Chairman
Committee on Taxation

FROM: Ed Sterner, Research E.S.
Committee on Taxation

SUBJECT: Multistate Tax Compact

The basic concern over the Multistate Tax Compact is that the allocation formula for corporate net income would result in little or no oil (and other multistate corporate) income being allocated to Alaska. It appears that this is not the case if the allocation regulations are properly implemented.

THE PROPERTY FACTOR: Both the Compact and the implementing regulations specify that oil reserves should be included in the property factor, not just capital improvements. This would ensure that Alaska's oil reserves are represented in the allocation of oil net income.

THE SALES FACTOR: The Compact is also clear that the sale of Alaska's oil, even if it actually occurs elsewhere, should be allocated to Alaska. The implementing regulations also strongly suggest this point. However, slight word changes or additions might help clear up any doubt. The allocation of Alaska oil sales to Alaska would also help ensure that Alaskan interests are properly represented in the allocation of oil corporation net income.

THE CORRECTION FACTOR: Finally, if the allocation formula still does not represent the role of Alaskan oil (or other resources) in the oil industry, then Article IV. 18. allows for either the exclusion of factors in the formula, or the inclusion of new factors, or an entirely different method of allocation if necessary.

At its peak, Alaska oil will very likely be supplying 10% of the nation's oil (1.8 - 2 M barrels per day out of 18 - 20 M barrels per day). It is possible that Alaska oil will represent more than 10% of tne owned or leased reserves of most oil corporations since oil outside North America and Western Europe is generally nationalized. Assuming the crude oil price is only half the price of refined oil, oil reserves are only half the capital worth of the oil industry (both are very conservative estimates), and the salary factor is basically zero, Alaska would still get a large part of oil corporation's net income.

0% = salary factor
5% = property factor
5% = sales factor

$$\frac{0 + .05 + .05}{3} = \frac{.10}{3} = 3\ 1/3\%$$

It should be remembered that this would be 3.3% of corporation net income after royalties, ad valorem, and severance taxes are paid.

In short, the Multistate Tax Compact, if used properly, should work to the advantage of Alaska. In 1973, only 3 of 10 oil producers in the state paid corporate net income taxes. I cannot envision this happening again if the Compact is properly implemented by Alaska. I would hope to determine in the next few weeks what effort the Department of Revenue is making to assure that the allocation formulas are being applied fairly to Alaska.

MEMORANDUM

September 23, 1975

TO: Senator John Huber, Chairman
Committee on Taxation

FROM: Terry Berman, Assistant TB
Committee on Taxation

SUBJECT: Scope of work

The staff met to discuss the scope of our work. It was agreed that we look at the areas suggested by the letter of Senator Croft to Governor Hammond, dated January 24, 1975.

These are:

1) The corporate tax structure.

2) The corporate tax structure of the oil industry with particular emphasis on such things as percentage depletion allowance and investment tax credit.

3) The advantages and disadvantages of taxation of oil in place by elimination of the present exemption.

4) Possible revision of the severance tax law in light of increasing oil prices.

5) The difference between rates of taxation of oil and of gas.

6) Such other matters relating to taxation of the oil and gas industry in particular, and taxation in general, as it deems advisable.

At present, we would like to concentrate on the more general areas of taxation, particularly the corporate tax structure, leaving the taxation problems of specific industries to a later time. In this way, we hope to form a base from which to attack the more complex areas such as oil and gas.

Specifically, the staff will be looking at fitting resources into the income tax structure. Ed Sterner is examining the Multistate Tax Compact. Frank Fleeks intends to review corporate income tax structure by researching the statutes of other states. He will also write a set of definitions of the various taxes so that we can have a standard guide.

I will be assisting Frank with his research and Ed with data analysis, taking charge of any programming that may be necessary. When they have finished their tasks, I will edit the reports and submit them to you.

ALASKA
STATE LEGISLATURE

MEMORANDUM

September 19, 1975

TO: Senator John Huber, Chairman
Subcommittee on Taxation and Revenue

FROM: Staff
Subcommittee on Taxation and Revenue

SUBJECT: Letter from Representative Nels Anderson, Jr., Chairman
House Resources Committee, dated August 1, 1975

In his letter, Representative Anderson requested the subcommittee to make three studies: 1) Study and evaluate the canned salmon industry to determine possible additional tax, 2) A study to determine what a fair and reasonable price per pound is for Alaska's salmon resource, and 3) A study to determine if the scales used for weighing salmon should be changed to another type.

It is the consensus of the staff that only the first requested study is within the mandate of the subcommitte. The second requested study can be better handled by the Department of Fish and Game, Commercial Fisheries Division. The third requested study should be referred to the Department of Commerce, Weights and Measures Section, as they have the primary responsibility for inspection and certification of scales used in commercial transactions, which includes the fishing industry.

Attached is a draft copy of a reply to Representative Anderson for your review.

ALASKA
STATE LEGISLATURE

MEMORANDUM

September 18, 1975

TO: Senator John Huber, Chairman
Sub-committee on Taxation and Revenue

FROM: Frank Fleeks
Tax Counsel for Sub-committee

SUBJECT: Meeting with officials of the Department of Revenue

The committee staff met with Fred Boetch, Deputy Commissioner of Revenue, and Gary Jenkins, Director of Audit. The purpose of the meeting was to establish lines of communications with the Department of Revenue. The discussion was general in nature with the committee staff members and the Revenue representatives giving a generalized view of what problems lay ahead.

The Revenue representatives promised complete cooperation in the obtaining of staff reports and other necessary data which they might have in their files. It was a short but fruitful session.

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A Talk with Dick Kilgore of Levy Associates in New York 7/29/75

Senator Huber, Senator Colletta, Judy Whitney-Assistant to Representative Bradner.

Levy Associates has said, for many years now, that you people in Alaska should be reviewing very carefully the corporate income tax because we can see, just off the top of our heads a number of problems with the way it is structured now. Whether that will get you an appropriate amount of income from Prudoe Bay we don't know but it should.

We have no lawyers on the staff here, so we can not address ourselves to the legal questions involved. We hope to make a real contribution through our knowledge of the oil industry and how various ways of apportioning, etc. may work for the oil and how much you may get out of it by taking various approaches to the Corporate Income Tax. Perhaps we can have some interchange with legal people who can answer some of the legal questions.

We have been following what is happening in Alaska and notice that the Department of Revenue has taken some steps to try to get more out of the Corporate Income Tax. They have noticed that a lot of corporations are accounting on a real line basis and showing losses on their operations in Alaska and therefore paying no Corporate Income Tax at the present time.

Formula Apportionment Basis. Really what you end up doing is that you get relatively little in the way of Corporate Income Taxes. Interstate Compact, COP ACT, Uniform Division Act, with its 3 formula thing takes the percentage of sales, property and payroll in Alask[illegible]

of the company's operation and then apportions the income to Alaska. Looking at the whole thing, it is unfortunate, but, that method turns out to be a very inappropriate kind of device for apportioning income to Alaska especially with Alaska having oil for leasing operations. Almost every factor really doesn't work.

I do not know how you people have looked at this or what knowledge you have of it, but... Looking at it briefly.

A lot of what I am going to give you is tenative but this is very clear to us, that there are so many problems in using such a formula in this case that it is not appropriate.

PROBLEMS AND THEN AVENUES FOR GETTING AROUND THIS. We have just gotten the materials on what other states are doing and are still thinking it through and seeing what other states are doing in this area and how they have come to grips with this thing. We are really just getting started in this area.

1) Sales factor. When looking at the oil producing operations, you find out that very little crude oil production is sold in Alaska. Most of it results in intregrated operations and therefore there is no sale in Alaska. It actually goes to an affileate refinery down in California or wherever it may be. So you end up with the sales part of this being zero. There are virtually no sales. (Noticed that your own Revenue people assume in their own projections of what you are going to get out the Corporate Income Tax that you are going to get 0% on sales from Prudhoe Bay, also. No sale just a transfer.)

Senator Huber and Mr. Killgore agreed that Alaska is unique in several ways and almost has to be looked at as a foreign country rather than just another state.

So sales is almost completely knocked out of the formula but you are still dividing by three. Utterly disasterous for Alaska. You need the sales factor.

2) Payroll factor. Almost as bad because what we are talking about is income from oil production and there are really very few people involved. Once we get through with Alyeska there ought to be none. When the real production starts it takes very few people to keep the whole production operation going. The big employment in the oil industry is in what? refinery ? Actually no, it is in marketing, home office, distribution, and this kind of thing. Employment in Alaska in all these areas as compared to elsewhere is going to be very small, meaning there will be a very very small percentage of the employment in Alaska. Yet, the profit in the future will be very big. So you have to have a formula that does not involve people or payroll or you will only get a very small portion of income allocated that way, but the income will really be generate from the oil production. The payroll factor is very very small. .

Department of Revenue says .08% on payrolls..

We have been trying to build up sort of a hypothetical oil company model that will be something on the scale of ARCO to show what they have outside Alaska and what they have inside and so forth.

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Colletta would like to see this done with Sohio.

Huber: Have you looked to see how the particular relationships between the companies and the pipeline itself enhances or further degrades us under the Interstate Compact Act?

Killgore: No we have not because of the way they operate. They may not be direct employees but rather employees of contractors with the apparent companies. We haven't looked into it but have notes on it and it is a potential problem. They just use contractors and for the other people that are not on the payrolls that is a problem.. I still think that if you looked at all the employees that are not directly on the payrolls you would still come up with only a very small ratio so it really doesnt help very much.

3) Property factor.. Probably the best way of the three but it still is not the solution. If you look at the oil exploration producing operations what you find is a lot of losses all over the place. One drills dry holes endlessly so there are a lot of expenses that are completely unproductive and are not put into the property accounts of the oil companies; they are just written off as losses. So looking at what gets left in those successful producing adventures such as Prudhoe Bay, and even with the very high costs involved you just don't have that much money actually spent. You still get a relatively small fraction because they have tremendous amounts of money invested in mining all over the place. There is an incrediable amount of money spend in marketing. You wouldn't believe the amount of money spent on gasoline station sites alone, and so on.

What you get are three factors, none of which are really good factors for income to Alaska.

Sales are virtually zero, payrolls you can hardly see, and property which is somewhat better but still by our own figures nowhere near the percentage of income that you would really allocate to Alaska if you did it on oil in place.

Department of Revenue. 12% on the property tax, .08% on payrolls, 0% on sales. Two of which you can not see, dividing by 3 and you end up with 4%. That is 4% of the company's total taxable income allocated to Alaska.

Preliminary numbers. Direct allocation. 1/3 of their net income being on oil production. Looking at where they may be when Prudhoe Bay production comes in, looking at their other operations and then looking at Alaska. The apportionment formula your own people would say 4% but on a generous basis it might come out to be 10%. (33% against 10%).

It is very clear that because of the nature of oil producing operations in Alaska that this formula is really inappropriate. You will end up way below what really is the profitability of oil production.

Huber: Donaldson of Sohio said that they own 52% of the North Slope Reserves and as such are a larger sharer in the pipeline that most.

B.P. remains the prim lease holder. They just sold their production. Very complicated. B.P. gets a certain percentage of production after a certain point.

Huber: In some of the definitions we put out. Any portion of the ABC plan is taxable as an interest. Just wonder if that right to purchase the gas reserves is covered.

I would be inclin[illegible] to suspect that Sohio would n[illegible]fit under that.

Huber: The conclusion is that Alaska needs to find a way to tax oil producers in the State of Alaska based upon the profitability of their Alaska operations the same as though they were an Alaska corporation doing the producing, selling, or whatever it is.

What is a fair share? In effect it is around 9% of what really is producing profit in Alaska.

Most obvious and what we have always thought of is, would be some sort of direct allocation scheme. It would appear, if you look at the law, (I don't have the Alaska Statutes but I have asked for it) and I am sure that you have it also - Uniform Division. This would imply that you could ask the administrator to keep reasonable various kinds of things like separate accounting, and other factors that you would need.

Must get at what the producting revenues are. Without worrying about the legalities and whether this could be done. Look at Prudhoe Bay production and what the individual company's production is and price it out that way and call it the revenue being generated from production. The pipeline should be separate accounting and you should deal with that as another tax issue.

Real question of how to handle the allocation of profit. May be a problem for the state. A lot of pretty serious questions on cost allocation.

Losses that companies have sustained in prior periods. How do you handle that? They have been making investments, drilling dry holes, have intangeble costs on drilling development at least for Federal Income tax purposes. They have been running losses and the question is how do you handle the carriage forward of this things.

Overhead. Things done for production in Alaska are done in Huston, Texas which adds another serious problem of how do you directly allocate those things. The more we think of these things the more we see potential problems.

In other states (and a reason why we try to look at what other states are doing) there seem to be provisions where one allocates costs on bases of revenue or something of that sort. Perhaps you can get around this by some simple formulas which would be reasonably acceptable and would give you a half way decent allocation of costs associated with the Alaska operation which really take place somewhere else and are really appropriate to charge against the Alaska cost.

Huber: Are you familiar with an income type taxation by any other producting countries?

Vertually every country has an income tax but in many countries the income tax and royality tax distiction has a blur. Back in the old days where there was a 50%/50% royality and income tax they were in a position to be rather arbitray about it. They said that the revenue was the posted price. That has changed but that is not our situation as we have the Constitution, Interstate Compact, etc.

Huber: Is there a way that we can get out of the Interstate Compact?

Yes, it is my undertand that you can get out of it. This is the kind of question that legal people in Alaska should be looking at. Dont rely on us for this kind of thing. Milton asked the Department of Revenue people when he was in Alaska and they said that yes you could get out.

Direct allocation. There are very clearly serious administrative problems. These can not be minimized, but perhaps it can still be done.

On the revenue side it would appear straight forward. One could just say that production times whatever the posted price is in Prudhoe Bay but the legal question you have to ask is, "Does that cause any future problem with any other state?" The companies are going to feel that they are being double taxed on sales. Here and in California there is a potential legal problem.

If you go "value added" and another state does apportionment based on total revenue which does not exclude the cost of coming in there is a potential problem. Maybe not.

The payroll factor would really be appropriate to the state of Texas because the oil companies have substantial payrolls is Huston and Dallas. The apportionment method would be good for them but Texas does not have a corporate income tax.

Cost allocation is not just a simple thing. Many different things have to be considered; however in concept it is the way to go.

Huber said that he will be sure that Levy Associates gets all the material that his committee works up that would relate to what they are doing.

Colletta: Asked some questions but he was too far from the micophone to pick up the questions, but basically he was concerned that Alaska be able to run Prudhoe gas off the big pipeline that goes to the Cordova area. There will be no way that we will be able to take any of the gas unless the company wants us to. There is a direct distiction. You can enter into any kind of contact that you want to with one exception that there will be no break in the area of regulation by Federal power. Louisana had to run a small line along side the large line to get by those regulations.

Huber: New pipeline committee with W. Bowman, chairman, is to find out all that is effected by the pipeline and that gas must be available to Alaska. There was discussion on how to protect gas for Alaskans and it was decided that this area will not be over looked, by the above mentioned committee nor any other group.

Colletta: If there are too many complications we could in the lease ask them to lay a small line along side the large one (pipe at our expense)

Kilgore agreed to furnish the committee with material on CH4 and CH3OH which he has. (Methol alcohol and methol burned instead of gasoline).

We will be looking at what other countries (non-Arab) are doing along with what other states are doing.

Discussed Witherspoons study.

Direct allocation [illegible] a fair way of doing it as lo[illegible]s the practical and legal problems are not so overwhelming. Other alternatives would have to be taken if there are legal problems, so we should not be concentrating all of our efforts in this one area.

If Alaska's law is like these others, I don't know why the Dept of Revenue went along with Sales, payroll and property as the three factors. One or two of them could be substituted for other factors that do relate, fairly. We are trying to think of other factors to modify the plan. Maybe "crude production" should be one of the factors..

Huber: Did you receive any of the materials that Bill Macguire had gotten on the taxes in the Cook Inlet? Do write to him for them.

We are looking at other states and so far it does not look like any other state has gone this direct route but then none of them have the problem at the scale that you do.

Huber: Milton informed me that you were working on a formula to be sure that Alaska received her full share in the Corp Income Tax.

Failing all else Alaska could go the Severance Tax route, but that would only be if other formulas can not be worked out.

Huber: The income tax should be our largest source of income so we will have to find a way to change the law so that it can be beefed up.

I agree that we must find a way of using the Corp Income Tax.