FISCAL POLICY AND THE ENERGY CRISIS

HEARINGS

BEFORE THE

SUBCOMMITTEE ON ENERGY

OF THE

COMMITTEE ON FINANCE UNITED STATES SENATE

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Part 2

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Appendix A

Draft of Final Report on Planning Criteria Relative to a National Research, Development, Testing, and Evaluation Program Directed to the Enhanced Recovery of Crude Oil and Natural Gas to

U.S. Atomic Energy Commission Division of Applied Technology

by

Gulf Universities Research Consortium

Prepared by: Joseph R. Crump and James M. Sharp

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ACKNOWLEDGEMENT

The contents of this report are based on data and information provided by those companies listed in Appendices A and B. Production and research personnel of these companies experienced in the enhanced recovery of oil and gas were exceptionally coöperative in developing the information, participating in conferences, responding to questionnaires, reviewing estimates and forecasts, and making their time available to the GURC staff for individual consultation. This high level of cooperation by the individuals and by their companies who supported their assistance to GURC in this investigation is gratefully acknowledged.

DEFINITION OF TERMS

Definitions of terms used in this report are included for crude oil in Appendix C and for natural gas and natural gas liquids in Appendix D. To the extent that they cover the terms necessary to this report, these definitions are identical with those included in "Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1972", Vol. 27, May, 1973, published by the American Gas Association, American Petroleum Institute and Canadian Petroleum Association. Where AGA/API/CPA definitions had not been established, additional definitions have been included in these Appendices.

DIGEST

Those critical forecasts and recommendations of crude oil and natural gas production experts participating in this investigation which bear on (1) the need for inclusion of research, development, testing and evaluation (RDT&E) directed to the enhanced recovery of oil and gas as a component in the nation's energy research and development program and (2) the character, scope, cost and time scale of the program required to make maximum contribution to the nation's requirements for oil and gas by 1985 are:

AS REGARDS RDT&E DIRECTED TO THE ENHANCED RECOVERY OF CRUDE OIL

1. Enhanced recovery of crude oil should increase domestic reserves by 18.5 to 36.3 billion barrels (approximately equal to 50 and 100 percent, respectively, of 1972 domestic reserves).

2. If exploited independently by industry with private risk capital, very little of these reserves will be produced by 1985 -- much less than is needed to help meet the nation's crude oil requirements and to minimize or eliminate dependence on imports.

3. Industry has developed a great deal of technology for the enhanced recovery of crude oil; however, only a few basic methods with limited proven range of application have reached the state wherein assessment of risk is sufficiently accurate to justify acceleration of application -- notwithstanding the very large increases in wellhead prices postulated.

4. Acceleration of enhanced recovery production can be achieved only by the firm definition of risk. This definition can be obtained only through the conduct of large-scale field tests in a large percentage of the 259 major producing domestic fields. For the acceleration needed to result in that production which is significant in terms of national need in the early '80's, such tests must must proceed concurrently with complete exchange of information.

5. This large-scale field test program cannot be justified on the basis of private investment alone. Therefore, a cooperative program amounting to an estimated $450 million over a 6.5 year period is recommended wherein required funding by the federal government is estimated at $235 million.

6. This program of large-scale field tests will compress the time scale for enhanced recovery production of crude oil by at least a decade. It should provide at least 423 million barrels of Annual Production in 1985 and Cumulative Production by 1985 of 1.8 billion barrels if initiated early in 1974.

AS REGARDS RDT&E DIRECTED TO THE ENHANCED RECOVERY OF NATURAL GAS

1. Enhanced recovery of natural gas could increase domestic reserves by 612 trillion cubic feet (approximately equal to 25 years of domestic production at the 1970 rate).

2. The alternative methods for producing these reserves are very limited and the probability of success is unpredictable at this time; therefore, attempts to exploit these potential reserves through private capital investment are very unlikely in the near future.

3. The primary requirement for determining both technical and economic feasibility of producing these potential reserves is a large-scale field test that would be conducted in each of three very large basins which include large amounts of federally owned land. Such tests must be directed to both the feasibility of the method and to the determination of those overall basin characteristics which would control production rate and potential recovery.

4. The only means for accelerating the possible production that would result from successful method development and demonstration -- and, therefore, confident evaluation of risk -- coupled with an

attractive market price is that of a cooperative industry/federal program wherein the required field tests in the three basins and corollary research and evaluation would be carried out concurrently with complete exchange of information.

5. This field test program can be completed in about five years. If economic production is demonstrated, the contribution that can be made to the nation's energy supply would be limited primarily by the rate at which wells can be drilled, formations fractured, and pipe lines constructed and could amount to 20-25 percent of the nation's annual requirements by 1985.

6. It is not feasible to estimate the cost of the required field tests accurately at this time; and approximate value for total cost of the field test program with supportive research as required is $250 to $300 million. Required federal funding is estimated at $125 to $150 million.

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I. DISCUSSION OF INVESTIGATIVE PROCEDURE AND VARIABILITY OF FORECASTS

This is the third and final report in a series covering a nine-week investigation to determine:

.. the extent to which possible price increases would result in increased production and reserves of domestic crude oil and natural gas through the application of enhanced (non-conventional) recovery methods;

.. the probable benefits to be derived from a federally supported, or partially supported, research and development program concerning the enhanced recovery of crude oil and natural gas as a possible component of a national energy program; and

.. the definition of the general character, content, time and cost of such a program.

The information presented in this report and in Interim Reports submitted on September 30 and October 22, 1973, was synthesized from data, forecasts, estimates and opinions of 36 oil and gas production research, forecasting and operating engineers selected by those companies listed in Appendices A and B as being expert and currently informed regarding enhanced recovery methods, problems, prospects and status of methods under development and/or test. A large number of these participants were also members of national level trade association and agency committees responsible for the acquisition and compilation of statistics on oil and gas production and reserves (wherein the emphasis is generally placed on conventional recovery methods in known fields) and, therefore, were intimately familiar with both the latest statistics (including as yet unpublished reports) and the means whereby estimates and forecasts were derived.

A series of conferences, sequential questionnaires, Interim Report reviews, and individual discussions were used as a modified Delphi procedure to develop an industry consensus relative to the stated objectives. It is pertinent to note that, not only was the time schedule exceedingly short for this development but that it occurred at a time when the nation's plans and requirements relating to its oil and gas supplies were undergoing a dramatic change. Therefore, it is useful to comment as to the

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variability of the estimates, recommendations, etc. from this fairly large sampling of oil and gas production expertise in terms of those aspects for which there was general agreement and those for which there was significant variation:

.. As regards the need and justification for a cooperative industry/federal government research, development, test and evaluation (RDT&E) program on the enhanced recovery of crude oil and natural gas, there was quite general agreement; i.e., industry considered such a program to be necessary, well justified, and advantageous both to the public and to the industry.

.. As regards the general character, scope, time scale and funds required for enhanced recovery RDT&E and the degree of federal support and participation essential to its early completion, there was exceptionally uniform agreement. I.e., there was no question that (1) accelerated production of crude oil and natural gas, by enhanced recovery methods, depended upon the immediate initiation of concurrent large-scale field tests with industry-wide information exchange, and (2) current limitations in field test data and production experience precluded the conduct of such a program independently by industry on any reasonable private risk-taking basis.

.. As regards quantitative forecasts and estimates of potential production and reserves that would be realized from enhanced recovery methods, there was wide variation -- particularly as regards time scale.

.. As regards "large-scale field test" methodology, there is general agreement but, also, significant minority opinion which should be considered in final test program design.

Because of the obvious importance of quantitative forecasts of Potential Additional Recovery and of Annual or Cumulative Production as a function of year, it is pertinent to suggest the reasons for variation in these quantities:

.. A principal reason is the honest disagreement among experts regarding the potential of a technology for which there are inadequate data upon which to base quantitative judgement -- however expert. This conclusion is supported by the emphatic agreement among the participants that limitations as to demonstrated technology preclude forecasting with sufficient accuracy to permit rapid and widespread production based on enhanced recovery methods on a reasonable private risk basis. Further, a historical comparison of forecasts relating to entirely different technologies and applications -- made at a comparable stage of technology development and involving the evaluation of private capital risk -- would reveal variations at least as great as those reported in this investigation.

.. The year 1985 had been designated as the key year for prediction in this investigation. Insofar as production of crude oil by enhanced recovery methods is concerned, the time lags accruing from large-scale field test, acquisition of equipment and materials, and reservoir fluid mechanics result in 1985 being very nearly the pivotal, or break-point year in a production vs. time relationship; consequently, forecasts corresponding to that point in time are subject to near-maximum variation. As regards the enhanced recovery of natural gas, the year 1985 is not particularly critical; however, there is considerably less confidence as to the amount of natural gas in place in tight reservoirs and below 15,000 feet than there is for the Remaining Oil-in-Place -- which are prime variables affecting any forecast of production and reserves.

.. A progression from "secondary" to "tertiary" production of crude oil (i.e., to enhanced recovery methods) and from "conventional" to enhanced recovery of natural gas involves an order of magnitude of greater complexity than did the progression from "primary" to "secondary" recovery of crude oil. The ability to forecast with accuracy the potential of this more complex production technology as applied to the wide range of pertinent lithological and operating conditions within the time scale of this investigation does not exist. Even the forecasting of production and reserves from known fields using conventional methods has required a comprehensive and prolonged effort on the part of both agencies and industry.

.. Definitions pertaining to the development of statistics and forecasts for conventional production methods have been carefully derived and have become totally familiar to the production industry. Comparable definitions for enhanced recovery methods have not been developed nor is there a standard terminology for the description of field tests. This factor has undoubtedly produced variations in forecasts of specific items as reported in questionnaire responses and correspondence as well as the obvious inconsistency between several of the interrelated forecasts as reported herein. Fortunately, some of this difficulty is compensated by this interrelationship of questionnaire items (which permits some retrospective analysis) and by direct consultation.

Despite these reasons for variability, the agreement on quantitative forecasts was greater than expected -- with about 2/3 of those participating in the forecasting being within reasonably close range of the average. Hence, quantitative figures reported are majority opinions. Further, forecasts which were decidedly either pessimistic or optimistic were about equally divided. Nevertheless, because of the reasons given for variability, it is considered pertinent to report the range of forecasts on critical criteria as well as the majority opinion. For these same reasons, it is apparent that the improvement on these forecasts can be achieved only by a field-by-field analysis conducted by enhanced recovery production experts. Even then, the lack of field test performance data would preclude confident estimates and forecasts.

II. PERSPECTIVE

This report is not considered to be in basic conflict with the previously published statistics and analyses, etc. appearing in the numerous national level studies and reports pertaining to crude oil and natural gas. Rather, those statistics, estimates, etc. (contained in such publications as the National Petroleum Council's "The Energy Outlook", the reserves and production report of the American Gas Association/American Petroleum Institute/ Canadian Petroleum Association, etc. -- and such unpublished material as the draft report of the Potential Gas Committee of AGA/API/INGAA, which are pertinent to this investigation have been used as basic criteria. Therefore, the criteria and recommendations contained herein are extensions of such basic reports wherein

- .. specific attention is given to enhanced recovery of crude oil and natural gas as the single topic of interest (and which has necessarily been a minor topic -- and a minor statistic -- in prior studies of much broader scope);

- .. the recent rapidly changing economic, energy and political situations (post-dating most of the published national surveys) can be considered in the development of new judgements;

- .. the estimates, judgements and recommendations are based on GURC's analysis of the response of operating, engineering and research personnel in the oil and gas industry to GURC's definition of national information needs; and

- .. being concerned with forecasts of enhanced recovery potential rather than the compilation of statistics on known reserves and production potential based on conventional recovery methods, these criteria represent expert opinion rather than the extrapolation of established statistics.

It is pertinent to note, however, that the forecasts as presented herein appear to vary from those in, for example, the "U.S. Energy Outlook" for enhanced (tertiary) recovery of crude oil. Specifically, Case II (the "intermediate") production projections in the "Outlook" indicate a probable production rate of crude oil of about 1.5 million barrels per day from known domestic fields in 1985. This 550 billion barrels per year is optimistic according to the majority opinion reported herein, particularly since the RDT&E effort as defined herein is not a prerequisite for that figure. Nevertheless, there was no disagreement among the participants in this investigation, that the RDT&E described herein will accelerate the enhanced recovery time scale by a decade or so, and projected Annual Production in 1985 reported herein, coupled with the nation's critical need for domestic crude oil, definitely supports the strong argument for such a program. It is notable, also, that the "Outlook" projections are not far different from the higher forecasts presented herein excepting that they are independent of the large-scale program of concurrent field tests considered essential to the forecasts developed under this investigation.

III. ENHANCED RECOVERY -- CRUDE OIL AND NATURAL GAS COMPARISON

Excepting the recovery of dissolved natural gas in the enhanced recovery of crude oil, the "enhanced recovery" of crude oil and natural gas are completely different in terms of both the basic problems to be solved and the nature of the methods needed for their solution. They are competitive only as means to provide alternate domestic sources of energy. They are complementary mainly in terms of the applications of basic geological and geophysical knowledge, materials and drilling technology, etc.

Enhanced recovery of crude oil requires a means for displacing oil from the reservoir rock, modifying the properties of the fluids in the reservoir and/or the reservoir rock to cause movement of crude oil in an efficient manner, and providing the energy and drive mechanism to force its flow to a production well. I.e., its purpose is that of making recovery possible and, of course, economical. On the other hand, enhanced recovery of gas requires no modification of gas properties nor the supply of other than the natural energy and drive mechanism inherent in the reservoir; rather, it requires the increase of production rate to an extent which makes recovery economical.

Enhanced recovery of crude requires the injection of chemicals or energy as required for displacement and for the control of flow rate and flow pattern in the reservoir followed by a fluid drive to force the oil toward a production well. Enhanced recovery of natural gas requires (1) the creation of a production well with sufficiently large area penetration into the reservoir rock that flow rates result in economic production, or (2) the solution of problems arising from the high temperatures and pressures associated with otherwise conventional recovery below 15,000 feet.

Enhanced recovery of crude refers generally (1) to "additional" recovery from fields wherein primary and conventional secondary (water flood and pressure maintenance) production has been completed -- or could have been -- or (2) to new recovery from fields where primary and secondary production were either impossible or uneconomical because of crude properties (generally high viscosity) rather than low values of porosity, permeability or oil-in-place. Enhanced recovery of natural gas refers to one problem only -- the economic recovery of natural gas from reservoirs with extremely low permeability and/or depths greater than about 15,000 feet. The term "enhanced recovery" as applied to crude oil appears preferable to "tertiary" since the principles and methods employed in enhanced recovery may be most effectively applied when the production of the field begins (as, indeed, secondary methods are now frequently employed concurrently with the initiation of primary production). I.e., "primary", "secondary", and "tertiary" imply sequential application (which has been the case traditionally) whereas overlapping or even concurrent application may well result in optimum recovery and production rate.

Considering that enhanced recovery refers to (1) crude oil recovered over and above that listed as Proved Reserves and Indicated Additional Recovery and (2) natural gas obtained by non-conventional methods from extremely low permeability fields, some approximate comparisons can be made which are useful in determining their importance as future energy sources. The following figures are subject to refinement in later discussion:

.. The average of the "reasonable estimates" of total enhanced recovery of crude and natural gas are, respectively (and approximately):

Oil: 35 billion barrels, or
20×10^{16} BTU

Gas: 500 trillion cubic feet, or
50×10^{16} BTU

Hence, in terms of enhancement of total energy reserves, they are both potentially large and are of the same order of magnitude.

.. For crude oil, both enhanced recovery technology and pertinent reservoir knowledge are more advanced than for natural gas; however, neither has advanced to the point where normal risk-taking private enterprise responding to even large market price increases would result in the production needed in the early and middle '80's. Production probability for specific fields is not sufficiently predictable to permit other than limited and sequential risks on a field-by-field basis for either crude or gas.

.. The principal requirement, if significant early 1980's production of either crude oil or natural gas is to be accomplished, is the rapid completion of a large-scale program of field tests -- as necessary to a high confidence level risk assessment -- which involve a large percentage of major producing fields.

.. The enhanced recovery of both crude oil and natural gas face definable time lags before large-scale production can commence:

... time for completion of field tests -- for both crude oil and gas;

... time to acquire materials, drill, and complete production installation -- for both crude oil and gas; and

... time from initiation of operations to initial production

.... determined by well spacing and fluid mobility in the field for crude oil,

.... determined by radiation safety requirements for gas using nuclear stimulation, and

.... negligible (by comparison) for gas using massive hydraulic fracturing or conventional production from below 15,000 feet.

At this very early stage of appraisal, both "enhanced crude" and "enhanced gas" constitute sufficiently large potential sources of energy to justify consideration as (1) prime energy sources for the next few decades and (2) sources of raw materials for chemical processing thereafter. Compression of the time scale for their availability is, therefore, the prime consideration. If coordinated large-scale field tests, as described generally herein, are initiated quickly, a very large time scale compression can be achieved. Further compression might be realized through federal subsidies of production readiness (i.e., early availability of chemicals, drill pipe and tubing, compressors, etc. in preparation for prospective need); however, this was not a suggestion by industry generally nor was this specific possibility investigated except in a few individual discussions.

This assessment of the differences in technology involved in potential RDT&E programs on enhanced recovery of crude oil and of natural gas indicates that the programs are best considered separately at this stage; hence, they are so treated in subsequent sections of this Report.

IV. SUMMARY OF FORECASTS AND RECOMMENDATIONS RELATIVE TO THE ENHANCED RECOVERY OF CRUDE OIL

A. Probable Effects of Price Increases

Figure 1 summarizes statistics presented in the AGA/API/CPA reserves study for rapid reference. As shown, an estimated 293 billion barrels of crude oil will remain in the ground after completion of primary and secondary recovery. The fact that none of this is included in Proved Reserves nor Indicated Additional Recovery is indicative of the abrupt increase in the difficulty and cost of recovery, the inadequacy of information of primary factors needed for accurate risk assessment, and the high cost of obtaining risk evaluation criteria (i.e., large-scale field tests). Were this not the case, the petroleum industry would already be actively exploiting enhanced (tertiary) methods to a much greater extent.

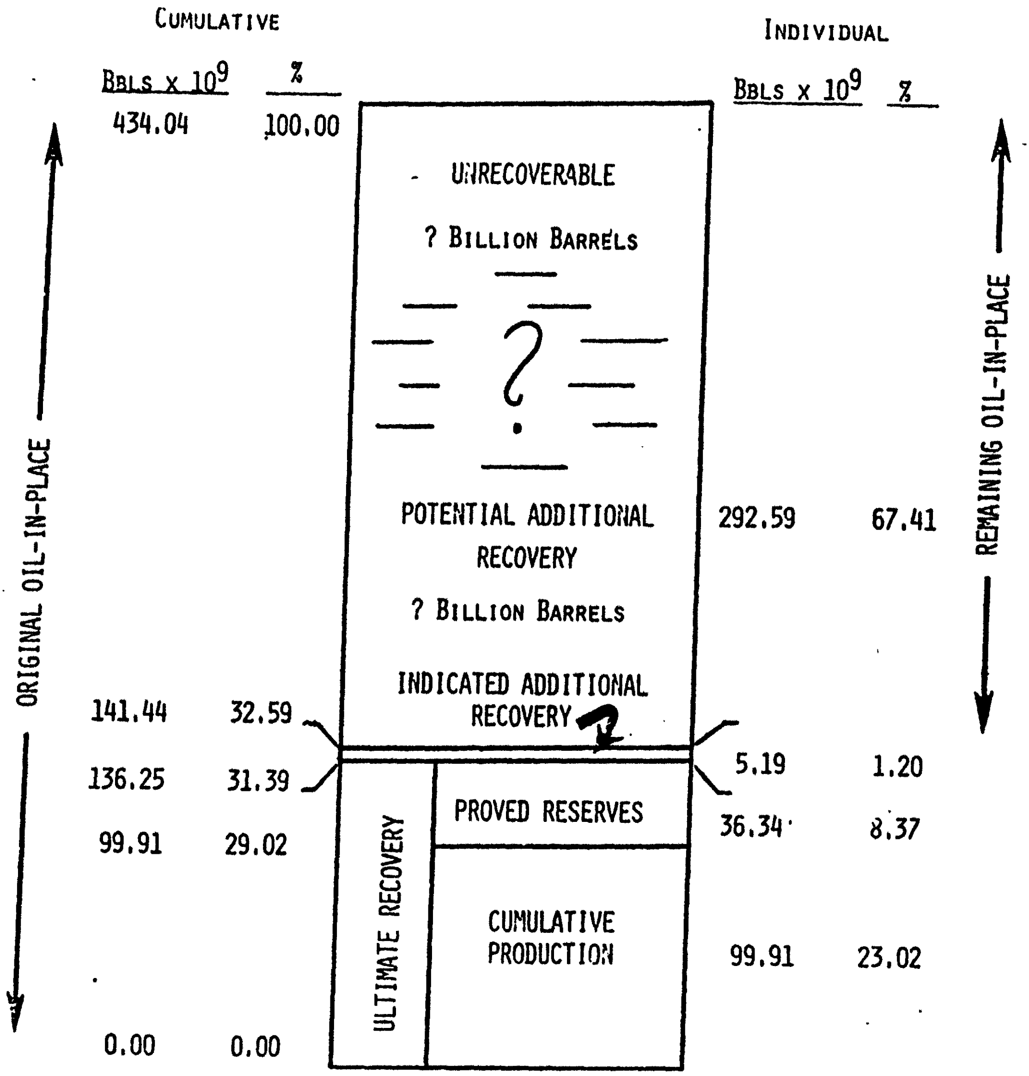
With rapidly decreasing supplies of crude oil and both current and predicted rapidly increasing wellhead prices, the incentive to accept a higher risk increases proportionately -- provided other factors do not control. Therefore, an early objective of the investigation was that of determining the probable effects of price increases of roughly 50 and 100 percent over current prices on a non-inflationary basis on the production and reserves of crude oil that would be realized through enhanced recovery methods, with emphasis on Cumulative and Annual Production through 1985.

The definite consensus of the industry participants as regards the effects of such price increases was:

.. Enhanced Recovery of crude oil is technology limited (in terms of adequate field test data and production experience) to such a degree that increases of even 100 percent over current prices would have little effect on production by enhanced recovery methods in the early '80's.

.. Because of the inadequacy of field test data and production experience and the costs of obtaining such information, production and reserves to be realized through Potential Additional Recovery by enhanced recovery methods cannot be predicted with sufficient accuracy and

FIGURE 1
CLASSIFICATION OF PRESENTLY KNOWN DOMESTIC CRUDE OIL RESOURCES
(434,038,198 THOUSAND BBLS., ORIGINAL OIL-IN-PLACE)
AS OF 12/31/72



Date from Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1972, Vol. 27, May 1973, AGA, API, CPA confidence to permit other than sequential field tests and, therefore, sequential production ventures regardless of wellhead prices. Admittedly, however, price increases in combination with the critical national need will result in greater than normal risk taking as regards all possibilities for increased domestic crude oil production, including enhanced recovery.

HOWEVER,

.. Enhanced recovery of crude oil will make a significant contribution to the nation's energy requirements in the early '80's if (1) the program of concurrent field tests as recommended herein is implemented immediately and (2) reasonable wellhead price increases accompany the development of field test data and information.

It is recognized that the firm consensus that large price increases would not result in early and widespread application of enhanced recovery methods by private industry and, therefore, in rapid increases in production by such methods in the near future is contrary to general opinion. Technical publications alone would indicate that much research has been completed by industry on the enhanced recovery of crude oil but that economic problems delay application. Therefore, their application as a result of price increase would appear to be reasonable. This investigation confirms that this is, indeed, the case. Industry is both willing and able to develop and apply enhanced recovery methods at a rate which is scientifically and financially prudent, taking into account its responsibilities to its stockholders. Further, the very recent energy crisis will undoubtedly result in the acceleration of enhanced recovery application by industry. The consensus, therefore, merits some explanation.

Indeed, there are numerous enhanced recovery techniques for crude oil which have been evaluated in the laboratory and in small (1/2 to 2 acre "five spot" or single well "mini-tests") which, if applied without regard to economics, will produce more of the Remaining Oil-in-Place after completion of secondary production (water flood and pressure maintenance). And certain of these techniques have been field tested on sufficient scales in time and spatial extent (with total test production of several hundreds of thousands of barrels) that they appear ready for major pre-production field testing <u>at least</u> in shallow (less than 3,000 feet) sandstones wherein (1) flow continuity and pattern can be reasonably well established from water flood production experience,

(2) porosity and permeability are adequate, (3) pay zone thickness and oil concentration are adequate, and (4) variability of reservoir properties and continuity of lithology and structure are reasonably well known. The application of these latter techniques in such formations appears economical (profitable) with relatively modest increases in the price of high quality crudes. Even within these restrictions, national production levels by such techniques are worthy of serious consideration in a national energy program. However, the majority of industry considers extrapolation of such methods to other fields with even comparable lithologies and operating parameters to be both high risk and not necessarily indicative of the optimum production method or technique for that field. Further, production from many major reservoirs (e.g., Gulf coast) with natural water drives is so efficient that further recovery by any method may be infeasible or uneconomical and, therefore, requires comprehensive testing. Therefore, the immediate application of even field-tested techniques is too unpredictable for major private capital risk (even at double the current price) until completion of tests in a large percentage of the major producing fields (currently, 259 fields, excluding Purdhoe Bay, in the U.S. account for about 90 percent of the present reserves, about 60 percent of the cumulative production, and nearly 70 percent of the annual production).

The major field testing required, if financed exclusively by private capital, must be done sequentially because of cost. Major acceleration of enhanced recovery requires that such field testing be accomplished concurrently in parallel field tests with free exchange of information as to field test results. The very firm consensus as to the reasons why such parallel tests cannot be undertaken independently by industry are:

.. Indeterminate Risk: The state of knowledge regarding enhanced methods and their application to varying reservoir characteristics, size, depth, lithology, etc. denies any reasonable estimate of the probable recovery in a specific reservoir. Only large-scale field tests supplemented with highly directed supplemental R&D can overcome this difficulty. Regardless, therefore, of a high price per barrel, the confident prediction of barrels to be produced is required if price is to result in probable profit.

.. Front-End Costs: Regardless of the basic method used, initial costs for enhanced recovery are very large. In, for example, methods employing entrained polymers for mobility control or surfactants for crude oil displacement, it is estimated that as much as eight pounds of chemicals are required to produce one barrel of crude oil from some reservoirs. Under these conditions, enhanced recovery production of a 10 million barrel field would require 80 million pounds of polymer -- WHICH MAY HAVE TO BE TAILOR-MADE FOR EACH FIELD. Other large front-end costs include the injection equipment (compressors) -- which, also, will generally be special order -- and preparation of the field (e.g., if it has already been water flooded, the water may have to be removed before enhanced recovery methods can be applied).

.. Time Lags: Three time lags -- to a large degree sequential -- impose a total lag in time-to-payout which further inhibits risk-taking. As stated, large-scale field tests must precede full field application; even such field tests require large amounts of chemicals and special equipment (which require time for production) and then several years may be required for fluids to move through a test site and generate production test data. Although larger initial investment will accelerate the learning curve through more comprehensive testing programs, no amount of capital will accelerate the slow rate at which fluids move through the reservoirs. Secondly, the production of the large amounts of front-end materials will require the construction of new chemical plants, some of which must have flexibility of end product. Thirdly, as in the field test, it takes time for a fluid drive, steam, fire flood, etc. system to move through the reservoir and drive the crude oil to the producing well -- encompassing some years in a sizeable field.

For these reasons, federal support of parallel field tests is essential to early '80's production by enhanced recovery methods. The primary benefit which will accrue from such support of field testing of these various technologies, and the incidental corollary research designed to optimize the benefit to result from the field tests, is that it permits the conduct of a significant number of field tests simultaneously. This will make available to the public more data on most of the individual tests than would normally be obtained by a company for its own purposes. And, very significantly, it will provide the basis for judging the optimum technology to be applied to a large variety of field conditions at a far earlier time than would occur otherwise. The result is far more rapid and wide scale commercial application than would otherwise be the case. In effect, the government, in the interest of making more domestic oil available at the earliest possible time, is assuming a risk which the industry cannot prudently assume.

B. Priority Criteria Relative to the Enhanced Recovery of Crude Oil

Priority appears to depend on forecasts of Annual Production in 1985, Cumulative Production by 1985, and Potential Additional Recovery. Because these are critical forecasts, the lowest and highest forecasts are included with the average value. As stated in Section I, about two-thirds of the forecasts were close to the average value with maximum variations being about evenly divided between high and low forecasts. The forecasts of subparagraphs 1 and 2 assume inclusion in the ERDA program of the cooperative large-scale field test program described herein beginning in 1974.

1. Production by enhanced recovery methods is estimated at:

a. Cumulative production by 1985:

(1) The "almost assured" estimate: 1.8 Billion bbls

(2) The "realistic" estimate: 3.4 Billion bbls

(3) The "reasonable" estimate: 5.9 Billion bbls

b. Annual production in 1985:

(1) Average forecast: 423 Million bbls

(2) Lowest forecast: 100 Million bbls

(3) Highest forecast: 800 Million bbls

Note: It appears that the average forecast for Annual Production in 1985 corresponds most closely with the "almost assured" Cumulative Production by

1985. Time lags described in paragraph A argue for the "almost assured" value of 1.8 billion barrels of Cumulative Production in combination with the average Annual Production in 1985 of 423 million barrels as being the most acceptable criteria for ERDA planning and priorities.

2. Potential Additional Recovery by enhanced recovery methods has been a consistent forecast throughout the several iterations of the modified Delphi procedure; again, the average is representative of about two-thirds of the participants, with higher and lower forecasts being about equally divided. The forecast values were:

a. The "almost assured" forecasts:

Average forecast:	18.5 billion bbls
Lowest forecast:	5.0 billion bbls
Highest forecast:	60.0 billion bbls

b. The "reasonable" forecasts:

Average forecast:	36.3 billion bbls
Lowest forecast:	15.0 billion bbls
Highest forecast:	100.0 billion bbls

This amount of crude oil (18-36 billion barrels according to the consensus) must be considered a major contributor to the nation's supply of both energy and raw materials for chemical processing in the next several decades. Should the higher forecasts prove correct, the importance of this resource would indeed be impressive. It should be noted that this consensus amounts to 6-12 percent recovery respectively from the 293 billion barrels of Remaining Oil-in-Place; the lowest forecast is less than 2 percent and the highest is about 34 percent.

3. <u>Relative Priority Considerations</u>

A large fraction of the production research and operations personnel participating in this program are employed by companies of sufficient size that their research and investment interests cover a fairly large part of the energy source spectrum. This is particularly true of those sources which might constitute an alternate source of crude oil or natural gas or substitutes therefor. I.e., company management, research, economic analyses, etc. have directed a significant investment of time, funds and facilities to the evaluation of alternate energy sources as means for maintaining or expanding their investment in the "energy business". Although the scope of this program was limited to enhanced recovery of crude oil and natural gas, it appeared useful to explore the relative position of enhanced recovery as basic means for obtaining energy in the near (1975-1985) future and beyond as compared with alternatives under active (and, in many cases, long) consideration by these companies. The opinions of the participants regarding RDT&E on enhanced recovery of crude oil as a component in the ERDA program in comparison with RDT&E directed to energy derived from oil shales, tar sands and coal were that enhanced recovery of crude oil was

.. favored over recovery from oil shales and tar sands almost 2:1 (NOTE: tar sands are located in Canada, which would affect relative priorities);

.. rated about equal with coal gasification but generally higher than coal conversion to syncrude; and

.. rated about equal with the removal of SO_2 from stack gases.

NOTE: While priorities and funding usually correspond, the above priorities <u>do not</u>; rather, they concern whether an ERDA program should include an enhanced recovery of crude component among its various alternatives rather than being concerned with relative funding.

That is, it is apparent that (generally reported individually since questionnaires were not directed specifically to this question) direct utilization of coal for energy production offers the most immediate opportunity for solving some facets of the energy problem but, also, that maximizing current oil and gas availability appears to be one of the nation's most urgent needs; hence, the recommendation that neither be omitted in an ERDA program.

C. General Recommendations

The following recommendations as to the need for inclusion of enhanced recovery RDT&E for crude oil and as to the nature of the RDT&E effort required have been unanimous and unchanging throughout the investigation:

1. The nation's energy program should include an accelerated RDT&E program directed to the earliest practicable production of crude oil by enhanced recovery methods.

NOTE: Certain basic considerations continue to be emphasized in support of this recommendation:

.. Potential Additional Recovery (that in excess of Proved Reserves and Indicated Additional Recovery) is sufficiently high to be of national importance.

.. Primary and secondary production in known fields is declining such that potential well shutdown is a present threat to the application of enhanced recovery methods. Once a well is plugged, there is little likelihood that enhanced recovery can be practiced economically. Once field production is terminated, lease ownership also terminates such that ownership may no longer be in the same corporate entity. Current shutdown and plugging

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exist principally in stripper wells rather than major producing fields; however, enhanced recovery will become necessary in major fields at a later time -- and sufficiently soon that accelerated application of enhanced recovery methods is desirable from this point of view alone.

2. The type of program required is a major cooperative program of parallel field tests with complete exchange of information. Primary characteristics of such a program are:

.. Each test operation must be conducted by the field operator (company);

.. Planning and evaluation must depend heavily on the utilization of engineering, economic, research and management expertise available from the production industry;

.. Field tests should be supplemented with such research and development as may be needed to improve field test measurements, data and information exchange, materials performance under varying lithologies and operating conditions, etc.;

.. Field tests must be on a scale in both space and time which permits accurate extrapolation to projected production from a specific field with sufficient accuracy to justify investment risk; in particular, the size must test intrafield variability in terms of its effect on displacement and sweep efficiencies. The nature of the field test required to satisfy these requirements varies significantly among the producing companies -- ranging from large acreage multi-well tests (the majority approach) to a large number of single-well (mini) tests; and

.. Direct, high confidence interfield extrapolation of field test results is unlikely even for comparable lithologies, structure properties, etc.; hence, some large-scale testing will be required in many of these 259 fields now providing 90 percent of domestic inland oil reserves. However, the size and duration of the tests can (probably) be downgraded in cases wherein other field tests included properties, geometry, water flood histories, etc. that are comparable.

Until recently, the highly competitive posture in the petroleum industry has been beneficial. This will continue to be true insofar as exploration is concerned. However, in the application of enhanced recovery, ownership is already established for the most part. Therefore, with a serious energy shortage, the principal need for the application of enhanced recovery being that of concurrent large-scale field tests, and the unattractive economic risk associated with private funding of an accelerated testing and applications program, both the public and the companies should benefit from the proposed cooperative approach. The above recommendations, then, are not contrary to the established competitive posture of the petroleum industry.

D. General Description and Relative Potential of Enhanced Recovery Methods

1. Basic Methods

There are four categories of methods (each with numerous variations in terms of procedures, materials, etc.) for enhanced recovery of crude oil for which current technological understanding would permit the consideration, and design, of field tests which should be definitive in terms of extrapolation to total field production.

a. Thermal methods (steam, hot water, *in situ* combustion, etc.) wherein heat energy is added to the formation to (1) vaporize average gravity oils which are otherwise trapped in the formation by capillary forces, or (2) reduce the viscosity of heavy crudes, and frequently generate pressure, as necessary to create economical production rates. Certain thermal methods have been in use to such an extent that they may not be properly classified as enhanced recovery methods; (e.g., steam "huff and puff" and hot water methods have been used for some years and now account for small amounts (on a national scale) of production. However, these were not distinguished from the more advanced concepts (e.g., COFCAW -- Combination of Forward Combustion and Waterflooding) in estimating the relative potential of the basic methods as shown in subparagraph 2.

b. Pseudo miscible methods (also termed "chemical, micellar, microemulsion, swollen micelle, soluble oil, etc. recovery") wherein

.. surface active agents in solution or in multi-phase dispersions are introduced into the reservoir rock to, respectively, reduce interfacial tension or miscibly displace the hydrocarbon or connate water through the reservoir rock. Thus, where oil external micellar dispersions are utilized, the oil is miscibly displaced through the reservoir and the connate water where, among other possible mechanisms, it is incorporated within the micellar dispersion as an internal phase in a pseudo-miscible displacement; and

.. the micellar (surfactant) slug is then forced through the reservoir using a polymer-thickened water for mobility (viscosity) control in order to achieve efficient volume sweep of the reservoir rock by the surfactant.

c. Carbon dioxide miscible methods wherein CO_2 is used as the agent to enhance oil/water miscibility and the CO_2 slug is driven through the formation by either water or gas.

d. Hydrocarbon miscible methods wherein a slug of hydrocarbon material (gas or liquid) with high oil miscibility is driven by gas pressure to displace oil from the rock and move it to production wells.

It must be recognized that any method utilizing surface active agents to achieve miscibility or pseudo miscibility and, thereby, displacement of the oil through the reservoir rock, must achieve and maintain high "displacement efficiency" throughout the specific field and, therefore, must be "tailored" for efficient performance over specific ranges of both chemical and physical variables (temperature, pressure, ion content and concentration, pH, crude oil properties, etc.). Similarly, chemicals used to provide mobility control and, thereby, achieve high "sweep efficiency" must also meet chemical/physical specifications based on field properties and conditions. Proposed (and lab-tested) chemical combinations for achieving displacement and sweep efficiency are, to say the least, numerous. Variations of the basic methods for thermal, CO_2 and hydrocarbon miscible methods are not as abundant but are, nonetheless, large in number.

The reservoir chemistry/physics/geometry conditions favorable to specific methods and techniques have been determined in a general fashion. Laboratory and very small-scale field tests predominate in the development of such criteria; only certain limited applications of thermal methods and a very few micellar systems have been tested sufficiently to permit reasonably accurate design of an enhanced recovery production plan and these are limited to fairly narrow ranges of depth, lithology, ion concentration, etc.

In considering the estimated comparative performance of thermal methods as presented above, it should be emphasized that this estimate does not apply to the large quantities of very heavy oils and tars for which "known" enhanced recovery production methods do not now exist. Rather, it refers to (1) oils which are too heavy for economical production at formation temperature wherein a realistic increase in temperature reduces viscosity sufficiently to permit economical production via a fluid route to the production well, or (2) oils of average gravity which are trapped by capillary forces wherein mobility is achieved by vaporization. For example, steam "huff and puff" might be used to create the continuous fluid route between wells after which other continuous flow methods (e.g., combination of forward combustion and water drive) might be established.

2. <u>Relative Production Potential of the Basic Methods</u>

The consensus of estimates of the relative amounts of enhanced recovery of crude oil that should be realized by the application of these four basic methods was:

a. Thermal: 29 percent

b. Micellar: 58 percent

c. Carbon dioxide: 8 percent

d. Hydrocarbon miscible: 5 percent

NOTE: The percentages for micellar and thermal methods were quite uniform among all participants. Those for CO_2 and hydrocarbon miscible varied widely in terms of percent deviation (ranging from nearly zero to as high as 12 percent, e.g., for CO_2), but there was complete agreement that the ultimate recovery from these two methods is much smaller than that to be expected from either thermal or micellar methods.

E. <u>Field Test Procedures and Configurations</u>

1. <u>Field Test Objectives</u>

The obvious objective of field testing is to determine the overall efficiency of production to be expected from the entire field. Specifically, it is necessary to ascertain the efficiency of the energy or chemicals used to displace oil in the reservoir and the uniformity with which the displacement fluid or energy moves through the producing formation -- i.e., the displacement efficiency and the sweep efficiency. The objective of field test design is to determine the test method, size and configuration of the test which permits confident prediction of recovery and production rate at least cost and time.

2. <u>Preliminary Evaluations</u>

In general, companies actively engaged in enhanced recovery development have completed:

.. Laboratory testing using field cores, both "fresh" and "restored", to obtain basic design parameters for a proposed test in a specific producing field. Many of these have been carried out for a number of method/field combinations;

.. Analysis of pertinent geophysical, outcrop, mud logs, well logs, core, and production data for preliminary evaluation of feasibility and design of the field test; and, in many cases,

.. Small-scale field testing generally designed to determine chemical stability in the producing formation and preliminary values for displacement efficiency. Such tests involve the smallest feasible (for test validity) travel of the injected energy, fluids, chemicals, etc. Frequently used approaches are

... Small (1/2 to 2 acres) "five spot" configurations (four injection wells at the center) -- such that travel is of the order of 100 to 200 feet from injection to the production well; or

... "Mini-tests: which involve single injection well tests with evaluations being made from the analysis of cores.

3. Test Method Variability

As stated in paragraph C,2, test procedures and configurations and the area and/or well spacing considered to constitute an adequate field test vary from company to company. They will also vary from field to field. Based on information such as that identified in subparagraph 2, a decision must be made as to the test size, configuration and method which adequately accounts for the effects of variability in the reservoir of such parameters as permeability, ion type and concentration, pH, formation thickness and conformation, etc. and thus permits accurate extrapolation of test results to the entire field. Under normal conditions, test costs dictate that testing in a single field be conducted in an incremental fashion -- beginning with a small "sample" of the field and expanding in planned steps to an "adequate" sample as test results direct.

In view of the nation's needs for crude oil, time becomes an important factor in the design of field tests. For maximum time compression, it is desirable that the number and size of test increments be minimal and, especially, that parallel field tests with information exchange be conducted.

This combination of important and generally independent factors influencing field test design precludes the possibility of "standard" field tests; also, it probably accounts for the general lack of standard terminology, test configuration, etc. mentioned in Section II. However, information exchange will greatly expand the utility of each field test and the ability to extrapolate data to different fields with comparable lithology and operating parameters.

4. Objectives of this Investigation

In this investigation, it has been necessary to define the general scope, nature, cost, etc. of individual field tests, the number of such tests that are required to accelerate enhanced recovery for national needs, and the total cost of the program. In spite of the variabilities mentioned in the previous paragraph, forecasts of duration, scope and cost of field tests were quite consistent as was the estimate of the total number of tests that would be required in the overall program.

5. Intrafield Test Size and Configuration

One factor which influences field test (and production) design is that the location and distribution of primary and secondary production or injection wells has often been dictated by governmental regulation or industry practice rather than optimum flow patterns in the reservoir. Essentially arbitrary stipulations of well density and arrangement designed to facilitate legal and regulatory problems have resulted in well distribution geometries which may not be optimum for water flood recovery (and, therefore, for most enhanced recovery applications also). In general, the application of enhanced (tertiary in such cases) recovery methods is more economical if maximum utilization can be made of existing water flood injection and production wells. Hence, large-scale field test patterns and plans, to a large extent, conform to existing arrangements of such wells in order that test costs be minimal. I.e., large-scale field tests tend to involve increments of 20, 40 and 80 acres.

Test geometries are generally described as "5-spots", "9-spots", or "line drives" defined as follows:

.. 5-spot: A square with four injection wells at the corners and a production well at the center.

.. Inverted 5-spot: Same as the 5-spot except for reversal of the injection and production wells.

.. 9-spot: Square with one production well at the center and three injection wells evenly spaced on each side.

.. Inverted 9-spot: Same as 9-spot excepting reversal of injection and production wells.

.. Line drive: Rectangular pattern with alternating rows of evenly spaced injection and production wells.

.. Single-well mini-tests: Uses injection in single wells with evaluations being made from cores taken short distances from the well, which are used:

... to compress the time required to complete a field test wherein results obtained are used as feedback in the design of continuing or future field tests and as input for laboratory research; and

... to supplement production-type tests (e.g., 5-spots) and large-scale intrafield testing wherein displacement values from mini-tests are used in conjunction with recovery data from the 5-spot test for extrapolating to a total field recovery value.

These geometries are descriptive, but far from all-inclusive, of the arrangements and incremental steps that might be optimum, in the field operator's opinion.

In attempting to determine field variability at minimum cost and time, the test designer appears to follow the 20, 40 and 80 acre increments but with additional wells drilled to reduce travel distance and time required for the tertiary "slug" to complete the transit from injection to production (or to smaller wells for coring interspersed between injection and production) wells. For square geometry the total travel distance between unlike wells would increase progressively from 140' to 330' to 660' to 933' to 1320' as the test acreage is increased from 1 to 5 to 20 to 40 to 80 acres. It is apparent that time compression as considered mandatory for early completion of field tests -- and, therefore, early '80's production -- will require careful design to meet both the requirement for valid variability determination and minimum time for completion. A "typical" suggested field test configuration is, for example, a "fully enclosed 5-spot" -- i.e., nine contiguous five acre increments with, therefore, nine production and sixteen injection wells. The "consensus" configuration, obtained by averages of well acreage and spacing, is about 30 acres and 726 feet respectively -- possibly indicating equal numbers of 20- and 40-acre tracts -- and requires a total of 22 wells. A total test of one 30 or 45 acre tract is not considered adequate for major fields; in fact, a rounded figure of $1000/acre/year for field testing used in conjunction with the total test cost figures reported in subparagraph 6 indicates that total test acreage in major fields would be of the order of 600-1000 acres. These large acreages are confirmed by individual consultation with a number of the participants.

The above figures for average test acreage and well-spacing appear to indicate that an overall large-scale field test program allowing for

.. sequential testing in some fields -- i.e., where small acreage tests are later expanded;

.. single well testing, in replicate, to determine formation characteristics and recovery method efficiency under field conditions;

.. terminated tests in some fields -- i.e., where measurements at the injection wells indicate inefficient and otherwise unsatisfactory performance;

.. extrapolation testing -- i.e., wherein results from one field are verified (but on a more limited field "sample") for application to another similar field; and

.. unusually large tests -- i.e., where either field size (and, therefore, recoverable oil volume) or variability is such that a large (400-600) acre sample is necessary for accurate extrapolation of test results to production and recovery probability

would probably consist primarily of a mixture of 20- and 40-acre test increments but would include a few that could be much larger.

6. Test Cost and Duration

The "mix" of tests, as well as the total numbers that must be conducted and in what sequence, in order to optimize both pre-1985 production and Potential Additional Recovery, would require an in-depth field-by-field analysis with complete industry cooperation. At this point, the consensus -- with considerable reservations until the in-depth analysis is made -- regarding the number, duration and cost of the average large-scale test is:

.. probable total number:	91
.. average cost per field test:	$4,100,000
.. average duration of field test:	53 months
consisting of:	
... planning and tool-up:	13 months
... conduct of test:	34 months
... final analysis (for field production purposes):	6 months

.. breakdown of average individual field test cost vs. time:

... months 1 - 6: 9.68 percent

... months 6 - 12: 25.43 percent

... months 12 - 24: 28.10 percent

... months 24 - 36: 18.05 percent

... months 36 - 48: 14.99 percent

... months 48 - end: 3.75 percent

7. The Field Test Program

The consensus regarding the total industry/federal cooperative RDT&E program which would be directed to the most effective combination of early production with maximum Potential Additional Recovery is:

.. probable program duration (assuming 91 tests as defined in E): 6.5 years

.. total field test costs (based on average cost/test in E): $373,000,000

.. earliest possible starting of individual field tests: 6 months

.. average time to complete preparation for field test (planning, procurement, drilling): 13.2 months

Questions directed to the participants resulted in unanimous agreement that, in the interest of collapsing the time scale as much as possible, some of the field tests already in final planning stages should be initiated as soon as feasible. Aside from the need for maximum time compression, a few cooperative tests underway would be a most useful guide in the development of the overall enhanced recovery RDT&E program.

Regarding federal/industry cooperative support of the field test program, it was the consensus that the ratio of funding should be somewhat flexible and should be responsive to individual proposals for conducting such tests, bearing in mind that a single proposed test will often involve use of a unitized field such that multiple-company "ownership" is involved for which there is a single operator. However, the general support formula considered consistent with investment risk, etc. ranged from 1:1 to 2:1 ratios of federal/industry support.

Assuming a 1:1 funding ratio, a federal cost for field test support only would amount to approximately $185 million. Estimates of required corollary research and development have not been made, nor can total agency/industry management costs be estimated independently. Therefore, it is recommended that a figure of $450 million be used for total program cost. The amount of cost sharing in the supporting research and management costs of the program has not been determined in this program. However, for the purpose of preliminary estimating at this time, the federal share of the total program cost is suggested to be $235 million.

The estimated "start-up" period of 13.2 months indicates that, should a program be initiated in early 1974, that most tests would not be initiated until 1975. However, there are field tests in final planning stages for which major commitments for materials and equipment could be made by mid-1974. Hence, 1974 should include the organization, program planning, proposed field test reviews, etc. as necessary to initiate the program with minimum delay.

Federal participation in the field test program as described should not be interpreted as applying to any further shortening of total production time scales; e.g., by overlapping the test phase with the development of materials and equipment for initiating full-scale production. This degree of time scale compression would be an order of magnitude greater risk from the point of view of industrial investment. Production front-end costs and time from production operation initiation to actual production is too long to permit industry underwriting on other than a subsidy basis, e.g., long-term loans to be paid out of profits.

8. Supporting Research, Development and Training

The participants generally endorse the need for research and development in support of the proposed field test program provided (1) it is closely coordinated with the field tests and (2) is directed to specific field test and subsequent production information needs. In so doing, it was stressed that the capability, in terms of personnel and equipment, resides within the petroleum industry. The cost of such a program cannot be estimated at this time; however, it is probably of the order of $10 million/year if it is to be effective on a time scale commensurate with information needs. Industry's RDT&E expenditures are currently estimated at (according to the consensus of participants) $81 million/year for enhanced recovery; of this, a very large fraction is for laboratory research, field analyses, etc. as contrasted with large-scale field tests.

The statement that supportive research capability resides primarily with industry was accompanied by numerous statements that there is a requirement that university scientists be included in an active role, not only to fill gaps and extend manpower in the basic research area, but to encourage and assist in the solution of a major developing problem -- the training of production engineering and research personnel. If the forecast of 20-35 billion barrels of production, with at least 1.8 billion barrels of Cumulative Production by 1985 and 423 million barrels of Annual Production in 1985 are realized, the order of magnitude of increase in the complexity of enhanced recovery as compared with "secondary" recovery indicates a need for a drastic change of compentencies and increase in the numbers of qualified engineering and research personnel that will be required.

Those areas of supportive research which are identified as requiring intensive effort are:

a. "Engineering geology" -- described generally as the development of methods for synthesizing information from all sources (core analyses, geophysical exploration, outcrop analysis, well logs, primary production history, etc.) as fundamental to the development of maximum information concerning the characteristics of a reservoir pertinent to the design of enhanced recovery production operations.

b. Geophysics -- directed to improved resolution and definition of reservoir conformation, fracture (hydraulic, etc.) configuration, improved lithological interpretation, definition of reservoir flow patterns, etc. -- using, for example, improved frequency, pulse, amplified modulation techniques; multiple reflection/refraction techniques, etc.

c. Surfactant research -- generally physical chemistry/chemical physics concerned with the definition of the mechanisms of action of promising surfactants under realistic reservoir conditions and to the development of improved surfactant solutions for enhanced recovery.

d. Sweep control fluids and methods -- generally concerned with improved performance and economics of mobility control fluids used to maximize sweep efficiency of "miscible" (micellar, CO_2, hydrocarbon) enhanced recovery methods; a specific example being development of suitable polymers which are stable under higher temperatures and wider ranges of ion (especially Ca and Mg) concentration.

e. Underground combustion -- directed to determination of mechanisms of action and means for improved displacement efficiency and mobility control, e.g., effects of oxygen enrichment on combustion rate and efficiency.

f. Systems analysis -- generally directed to the interdependence of enhanced recovery/environment/water supply/manpower/material supply/etc. for overall management and scheduling purposes.

g. Test method development -- directed to improving and simplifying both laboratory and field measurements for field test application and leading to the development of optimum or standard procedures for use in the cooperative field test program.

V. SUMMARY OF FORECASTS AND RECOMMENDATIONS RELATIVE TO THE ENHANCED RECOVERY OF NATURAL GAS AND NATURAL GAS LIQUIDS

A. Introduction

The Second Interim Report included only the "first round" of commentary on gas. Since the issuance of that report, very extensive discussion, both written and verbal, has served to extend and to modify the previous report. The additional round of comment has permitted the authors to obtain more recent data and to indicate more clearly the degree of consensus.

B. Project Procedure

The procedures followed in developing information on natural gas production have been quite similar to those described for the crude oil studies. As a preliminary, several individual discussions were held, in order to ensure appropriate design of a questionnaire and an efficient conference.

On Tuesday, 9 October, 1973, a Conference was held in Houston, attended by representatives of major gas producers and major gas transmission companies. A detailed discussion was held and completed questionnaires were obtained from fifteen companies.

A large number of individual discussions with participants have been held subsequent to the Conference in order to clarify and extend the information given on the questionnaires.

The results of the "first round" (i.e., the Interim Report) were submitted to participants for commentary, correction and extension.

Several additional companies who were not able to supply appropriate personnel on short notice for the Conference indicated their desire to receive the interim results and have responded on the "second round" of data.

C. The Nature of Enhanced Recovery of Gas

The term "enhanced recovery" has, for the most part, a distinctly different meaning in the production of gas as contrasted to its meaning in the production of oil. In the production of oil, enhanced recovery involves literally displacing the oil from the pores of the formation and "sweeping" it towards a well through which it may be produced. In displacement of oil from the reservoir rock, a "washing" or heating action may be used: light hydrocarbons (propane or butane) may be used to miscibly displace the crude oil; or surfactants may be used to modify the properties of the crude oil and to form micelles, microemulsions, etc. which are more readily transported through the formation. In situ combustion may be used to reduce viscosity or partially vaporize and create pressure which will accomplish displacement. In some cases, fracturing of the formation (or acidizing) may be used to open up increased surface and create channels for higher rates of flow.

In the case of gas production, the latter concept, fracturing of the formation to increase the rate of production, is much the most important factor. In massive hydraulic fracturing, the result is the creation of fissures of varying size, connecting to the well bore, which enormously enlarges the amount of surface area of the formation from which gas can flow to the well.

In nuclear stimulation, a large cavern or "chimney", almost completely filled with rubble, is produced. The extent to which fracturing of the surrounding formation occurs is documented in great detail for certain tests (see, for instance, Project Gasbuggy; El Paso Natural Gas Company, U.S.A.E.C. and U.S.B.M., 1965, and, Report of National Gas Technology Task Force for Technical Advisory Committee of the National Gas Survey by U.S.F.P.C., 1973). The size of the "chimney" plus formation fracturing greatly increases the area available for gas flow. The results of such an operation may differ greatly from one formation to another; and a substantial amount of further test and evaluation would be needed in order to insure more general application of the method.

D. Methods of Enhanced Recovery of Gas

As indicated in the previous section, enhanced recovery of gas is largely a question of fracturing large formations of almost zero permeability, so that the rate of production from the formation will be very greatly increased (i.e., by a factor of 10 to 1 up to 100 to 1). At the present time, the methods which appear to be promising are (a) nuclear stimulation, (b) massive hydraulic fracturing, and (c) possibly, some combination of (a) and (b). The details of nuclear stimulation and hydraulic fracturing have been covered thoroughly in various documents produced by national level committees such as that listed in Appendix B, and especially in the reports of the National Gas Survey made for the Federal Power Commission. Therefore, only brief descriptions of the basic concepts will be offered in this present report.

It is known that very large supplies of gas exist in the U.S. (notably in the Rocky Mountains' area) which cannot be produced because the formations are extremely "tight". That

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is to say, the permeability is so very small that the rate of production is totally uneconomical. (The National Gas Survey by the F.P.C. cites the Uinta, Piceance and Green River Basins, with great detail on the data available to date). Thus, the problem appears as one of rate of production, rather than magnitude of displacement as in recovery of crude oil. (The amounts of gas which might be recovered are discussed in Section E).

In nuclear stimulation, the nuclear explosive device is placed in a well drilled into the formation. When exploded, it produces a "chimney", a region of thoroughly fragmented rock of considerable size. Connected to the chimney is a system of radial fissures in the formation, enormously increasing the surface area through which gas may be produced.

The concept of a single explosive device is readily extended to that of several devices placed in a vertical line, producing a chimney of much greater vertical dimensions. (In order to limit seismic effects, these could be exploded sequentially). Present information indicates that devices of 100 kilotons of energy would be appropriate.

A number of objections regarding the impact of this method on nearby inhabitants, and on the environment, have been examined carefully. The radiation hazard, when examined quantitatively, is negligibly small. Inconvenience to inhabitants nearby can be reduced to a day or two of evacuation at most, for a small number of people. Seismic hazards appear to be negligible.

The technology, however, is far from being complete; and the economics for depths up to 10,000-15,000 feet appear to be less favorable than those of hydraulic fracturing. However, the potential for increased energy supplies is so large that nuclear stimulation should be more thoroughly tested. There is a great diversity of opinion among the major gas producers concerning priorities; but the definite majority opinion (but with some very definite disagreement from the minority) is that nuclear stimulation tests should be included in the proposed program, and that such tests should commence at the earliest possible date. In the spectrum of research development, testing and evaluation, it is felt that priority should be given to field tests and evaluations thereof.

It should be noted (with reference to the paragraph just above) that assumptions in some of the economic calculations involve uncertainties far greater than the resulting calculated differences between the two technologies. Slightly different assumptions regarding operational or equipment costs or regarding the reservoirs themselves might alter radically the relative economics. In our present state of knowledge, both technologies are worthy of careful consideration.

In hydraulic fracturing, a suitable hydraulic fluid (generally an aqueous solution), is pumped into the well at high pressures (10,000 psi or higher) at the well head. This pressure, added to the pressure created by the hydrostatic column in the well, is exerted on the formation, producing fractures which greatly enlarge the surface area available for gas to flow from the formation. Since the fractures would tend to close up when the hydraulic pressure is removed, "propants" are added to the fluid which is pumped into the well and hence into the formation. The purpose of the propant is to remain behind in the fissures as the fluid recedes and hold the fissures open.

It has been suggested that combinations of nuclear stimulation and hydraulic fracturing may be used. For instance, hydraulic fracturing (with propants) might be applied to several wells surrounding a central well to which nuclear stimulation has been applied. No data are available on such combinations but it is felt that they should be considered as possibilities.

Enhanced recovery from conventional wells (i.e., with economically reasonable permeabilities) may result from displacement methods (possibly associated with enhanced recovery of crude oil) or by using compressors to reduce surface pressure (hence, "sucking" more gas out of the formation). The quantities which may be recovered in such operations, however, are extremely small as compared to opening up tight formations by nuclear or hydraulic fracturing. In very special circumstances, the dewatering of water drive reservoirs, or displacement by nitrogen or carbon dioxide may be feasible.

E. Potential Recoveries

Estimates of natural gas reserves, of the amount of gas remaining in place in producing reservoirs, of the amount probably available in reservoirs as yet either undiscovered or not produced, and particularly that recoverable from formations having extremely low permeability, are highly controversial -- simply because of (1) the extreme difficulty of arriving at high confidence level estimates (on which contracts for delivery must be based) and (2), in the case of the gas in "tight" formations, the dearth of direct observational information -- i.e., core analyses and production measurements. Serious attempts by highly qualified experts have been made to provide the best available figures for national planning purposes, which are presented in well documented reports. There is no real alternative to acceptance of such figures for broad planning purposes at this time; hence, the following figures are reproduced from the National Petroleum Council's "U.S. Energy Outlook" as being as good a summary of the natural gas supply picture as is available.

NOTE: All figures are given in trillion (10^{12}) cubic feet. Definitions of terms refer to those used by the Potential Gas Committee or those given in Appendix D of this report, which are taken from the AGA/API/CPA Reserve Studies.

Cumulative production to 31 Dec 1972	433
Proved reserves, as of 31 Dec 1972	266
Future potential supply (conventional reservoirs, as of 31 Dec 1972 estimate)	1,146
Subtotal (including cum. production)	1,845
Potentially available as gas-in-place in Uinta, Piceance and Green River Basins (tight formations)	600
Potentially available as gas-in-place in other basins (tight formations)	625
Subtotal	1,225

The figures given for "conventional reservoirs" is recoverable gas, a recovery factor of 85% having already been applied. Applying a 50% recovery factor to the tight formations (after fracturing), the following future recoveries can be anticipated:

Conventional:	(1.00) (1412)	=	1,412
Tight:	(0.50) (1225)	=	612
			2,024

(For purposes of perspective, this may be compared to 22.5 trillion [10^{12}] cubic feet produced in 1972).

In the opinion of some qualified experts, the amount of gas available in tight formations (not available without massive fracturing) may be two or three times as large as is indicated above. Conversely, a substantial number of experts feel that the figure given above for conventional gas yet to be discovered (1146) may be an upper limit of optimism. As much as 50% of this, perhaps, is in Alaska, or in the deep offshore, or at depths of 15,000 feet plus. Availability, therefore, depends specifically on rapid development of reliable technology for the specific circumstances.

F. Conference Conclusions and Recommendations

1. General

During recent months, substantial increases in well-head gas prices have occurred. Such changes have naturally stimulated production by encouraging exploration, by closer well spacing, and by encouraging use of compressors to lower the "abandonment pressure" of operating fields. These increases in production are important in the very short term, but are not significant in the longer time scale and in view of the nation's total future needs, excepting exploration's effect on new discoveries.

Given a gradual rise (a relatively free market) for gas, the conventional fields of reasonably high permeability will be discovered and produced. This does not, however, constitute enhanced recovery in the sense of increase over and above anticipated conventional recovery.

On the other hand, successful development of methods for producing very tight formations could increase very significantly the total long term energy resources available to the nation and contribute significantly to short term (1980-85) production.

2. Economic and Policy Factors

It is important to recognize the nature of risk-taking in production of oil and gas, where enormous sums of capital are required to conduct any significant operation. If a program of RDT&E is established, private enterprise will almost certainly be forced to adopt a sequential approach to the various steps involved. Such an approach might easily require a period of ten to fifteen years to accomplish, since certain parts of the program (especially field tests) may require two or three years to accomplish.

If the national interests are to be served best, it will be necessary to collapse the time frame as much as possible by overlapping or concurrent operations; wherein operations are carried out cooperatively by private industry, universities and Federal agencies. (Obviously, the companies will have to be guaranteed protection against any anti-trust charges). Such an approach departs somewhat from the established patterns of competitive enterprise which must make a profit in order to survive. It is quite improbable that gradual increases in price of gas would be sufficient incentive for the drastic shortening in time scale which the nation's present energy situation requires.

Federal funding of RDT&E programs in cooperation with the industry is that device which can accomplish the desired result within the least time.

3. Formulation of RDT&E Program

Although there is considerable divergence of opinion among the participants regarding priorities and technical merit of certain methods, the following represents a majority opinion concerning a federal/industry cooperative RDT&E program on enhanced recovery of natural gas. A structure for completing detailed formulation and subsequent operation is proposed in paragraph 4.

a. Fracturing Technology

The development and testing of production methods for tight formations could open up to the nation an enormous increment to its present energy supply. The following items are considered to be paramount in such a program.

(1) A program of cooperative research, development, testing and evaluation should be developed and implemented immediately, with emphasis on testing and evaluation.

(2) Major emphasis should be placed on technology of producing tight formations by nuclear stimulation and massive hydraulic fracturing. Present evidence suggests that hydraulic fracturing offers better economy; however, the economic studies are extremely sensitive to very minor changes and present calculations should not be considered as being

conclusive. There is a wide divergence of opinion regarding the feasibility of nuclear stimulation. However, neither method has been adequately studied. Programs should be formulated which will give conclusive technological and economic results on both methods.

(3) Combinations of nuclear stimulation and hydraulic fracturing should be considered.

(4) Reservoir definition deserves a great deal of attention, if tests are to be meaningful. For instance, the Uinta, Piceance and Green River Basins might be drilled along transects, with forty to fifty wells per basin. It must be recognized that variations in permeability, and inhomogenities in structure very significantly influence the production, characteristics of the reservoir -- including definition of the size and pattern of fractures required for economic production.

(5) Supplemental basic research and development should be conducted on specific topics such as propants, permeability definition, core testing, and properties of fracturing fluids.

(6) With reference in part to item (4) above, the optimization of well spacing should be studied.

b. <u>Other Enhanced Recovery Considerations</u>

Attention should be given to more conventional problems, in addition to the factors discussed above for tight formations. The following factors are concerned primarily with insuring a rapid increase in both production and proved reserves.

(1) Some degree of attention should be given to studies of conventional reservoirs. It is felt that gradual price increases now occuring may be of sufficient incentive in this situation, eventually; but acceleration of effort is needed.

(2) Injection of inerts (displacement methods) is regarded as being of extremely limited application.

(3) Deep wells -- 15,000 feet and deeper -- deserve special study. The temperatures and pressures encountered at these depths are sufficiently high to modify the properties of fluids and other materials, and, therefore, equipment design and operating methods used in drilling and fracturing; and such modifications make drilling and fracturing in these wells uncertain and unduly expensive.

(4) Research to define further the potential for production of methane from coal seams (not coal gasification) should be undertaken.

(5) General industrial logistics must be considered. A major production program of enhanced recovery would create significant increases in requirements for trained personnel, equipment (tabular goods, compressors, well-heads, rigs, etc.), well completion items, and transportation facilities.

(6) It is felt that gradual price increases, though resulting in increased conventional production and exploration, will not accomplish an adequate expansion of gas production at the rate called for in the present situation, because of technology limitations which can be overcome only by rapid progress in RDT&E.

4. Structure of an RDT&E Program

The program should be a cooperative effort by government, industry and qualified academic personnel.

The planning effort should be commenced at the earliest possible time; with the intention that preliminary plans (permitting commencement of some projects) may be completed within 3-5 months; and that a comprehensive plan may be completed within 6-8 months.

The funding should come jointly from government and industry, with some formula which provides the government with adequate compensation where tests are successful on a large scale; and mutual write-off for failures. (It should be noted that the three basins suggested for tests involve large tracts of Federal lands).

Planning, review and policy direction should be maintained by a council or committee broadly representative of all phases of the industry, of government, and of qualified academic experts. It must be acknowledged, however, that the great part of the expertise and of the operational capability lies in the production and associated research divisions of the industry. Also, it is clear that operational control is the function of the field operator subject to review by other leaseholders in that field as well as by such a council.

The American Gas Association has commenced planning on an extensive program of research covering nearly all phases of the gas industry, including production. A program of RDT&E as described herein should be coordinated with the production phase of the AGA study from its earliest stages. It is probable that such coordination would be automatically insured by the nature of the planning groups. (It should be noted, for instance, that a number of the participants in the development of this report are aware of or even directly engaged in the AGA planning effort; and no sense of conflict whatsoever is apparent).

5. Natural Gas Liquids

Natural gas liquids (NGL) constitute a significant fraction of our hydrocarbon resources. They are produced along with natural gas. (See Appendix D for definition and description. Roughly speaking, NGL is in the propane-hexane range). In 1972, U.S. production of NGL was 756,000,000 barrels, as compared to 3,281,400,000 barrels of crude oil -- slightly less than one-fourth.

The ratio of NGL production to natural gas production has remained approximately constant. (In 1972, the ratio was about 34 barrels of NGL per million cubic feet of gas). In the opinion of many of the participants, there is no reason to predict a significant change in this ratio. Hence, production of NGL might be expected to be directly proportional to production of natural gas. Some data indicate, however, that the NGL content of the typical tight formations is much lower than the general average (perhaps of the order of 1/10). When, and as, the tight formations become significent factors in production, therefore, the ratio may be expected to drop significantly.

APPENDIX A

COMPANIES PARTICIPATING IN THE DEVELOPMENT OF FORECASTS AND RECOMMENDATIONS RELATIVE TO ENHANCED RECOVERY OF CRUDE OIL

Amoco Production Company

Atlantic-Richfield Company

Chevron Oil Field Research Company

Cities Service Oil Company

Continental Oil Company

Diamond Shamrock Oil and Gas Company

Esso Production Research Company

Gulf Research and Development Corporation

Husky Oil Ltd.

Marathon Oil Company

Mitchell Energy Company

Mobil Oil Corporation

Mobil Research and Development Company

Pennzoil United, Inc.

Phillips Petroleum Company

Quaker State Oil Refining Corporation

Shell Oil Company

Sohio Petroleum Company

Sun Oil Company

Superior Oil Company

Tenneco Oil Company

Union Oil Company of California

APPENDIX B

COMPANIES PARTICIPATING IN THE DEVELOPMENT OF FORECASTS AND RECOMMENDATIONS RELATIVE TO ENHANCED RECOVERY OF NATURAL GAS

Amoco Production Company

Chevron Oil Field Research Company

Continental Oil Company

Diamond-Shamrock Oil & Gas Company

El Paso Natural Gas Company

Esso Production Research Company

Gulf Research & Development Company

Lone Star Producing Company

Mitchell Energy Company

Mobil Research & Development Co.

Phillips Petroleum Company

Shell Oil Company

Superior Oil Company

Tenneco Oil Company

Texas Eastern Transmission Corp.

Transcontinental Gas Pipe Line Company

Trunkline Gas Company

Union Oil Company of California

APPENDIX C

CLASSIFICATION OF PRESENTLY KNOWN DOMESTIC CRUDE OIL RESOURCES and DEFINITIONS OF TECHNICAL TERMS PERTAINING THERETO

The use of a few carefully defined technical terms is essential in discussing the nation's crude oil resources, in order that fallacies of thought and understanding not be created by ambiguities of language.

Fortunately, the technical terms that identify various classifications of the total domestic crude oil resources are well established by agreement and common usage within the petroleum industry. They are also relatively simple in concept and in derivation. Those terms used in this report, illustrated diagrammatically in Figure 1 of the text of this report and repeated in this Appendix, are defined briefly as follows:

CRUDE OIL --

A mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through processing facilities that separate out some components. The reported volumes of crude oil also contain a very minor amount of other liquids which is statistically insignificant but technologically either difficult to separate at one place or desirable to include at another. Crude oil is reported in units of stock tank barrels of 42 U.S. gallons at atmospheric pressure corrected in volume to 60°F.

PROVED RESERVES --

As of December 31 of any given year, the estimated quantities of all liquids statistically defined as crude oil, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation tests. The area of an oil reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas-oil or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled but which can be reasonably

Appendix C - continued

judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves of crude oil which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir provides support for the engineering analysis on which the project or program was based.

Estimates of Proved Reserves do not include the following: (1) oil that may become available from known reservoirs but is reported separately as "indicated additional reserves"; (2) natural gas liquids (including condensate); (3) oil the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (4) oil that may occur in untested prospects; and (5) oil that may be recovered from oil shales, coal, gilsonite and other such sources.

INDICATED ADDITIONAL RESERVES --

Crude oil potentially available from known productive reservoirs in existing fields expected to respond to improved recovery techniques such as fluid injection where (a) an improved recovery technique has been installed but its effect cannot yet be fully evaluated; or (b) an improved technique has not been installed but knowledge of reservoir characteristics and the results of a known technique installed in a similar situation are available for use in the estimating procedure.

The economic recoverability of these reserves is not established with sufficient conclusiveness to allow them to be included in Proved Reserves. If and when improved recovery techniques are successfully applied to known reservoirs, the corresponding Indicated Additional Reserves will be reclassified and added to the inventory of Proved Reserves.

Indicated Additional Reserves do not include reserves associated with acreage that may be added to the area of a proved reservoir as the result of future drilling.

Appendix C - continued

ORIGINAL OIL-IN-PLACE --

Calculated volume of crude oil in known reservoirs prior to any production. Known reservoirs include (1) those that are currently productive; (2) those to which Proved Reserves have been credited but from which there has been no production; and (3) those that have been depleted.

The volume of Original Oil-In-Place is based on calculations using volumetric or material balance methods when sufficient factual data are available concerning reservoir rock, fluid properties, reservoir limits, and production performance. Where such data are not available, or are seriously incomplete, the volume is estimated on the basis of information and performance characteristics from reservoirs believed to be comparable.

ULTIMATE RECOVERY --

Volume of crude oil (1) which has been produced from a reservoir, and (2) is expected to be produced in the future if there are no substantial changes in present economic relationships and known production technology. Accordingly, the current estimate of ultimate recovery is the sum of Cumulative Production to date plus the current estimate of Proved Reserves.

Ultimate Recovery may also be expressed as the percentage of Original Oil-In-Place which is expected to be eventually produced. This percentage will vary from one reservoir to another in accordance with the reservoir fluid, rock characteristics, and the producing mechanism or drive which is present.

PRODUCTION --

Volume of liquids statistically defined as crude oil, which is produced from oil reservoirs during given periods of time. The amount of such production for a given year is generally established by measurement of volumes delivered from lease storage tanks (i.e., the point of custody transfer) to pipelines, trucks, or other media for transport to refineries or terminals, with adjustments for (1) net differences between opening and closing lease inventories, and (2) basic sediment and water (BS&W) which settles out of the oil in storage tanks.

Appendix C - continued

For purposes of the annual reserves reviews, production data for individual fields and for the specific geographic areas are needed. Since "official" sources such as state agencies and the U.S. Bureau of Mines do not provide the required detail, all available data (including company records, commercial services, state records, and Bureau of Mines reports) must be reviewed. Because of differences in definitions and differences in data collection procedures used by various sources, and because of the variety of adjustments which must be made, production data used in annual reserves reports should not be expected to agree precisely with that published by such sources as state agencies and the U.S. Bureau of Mines. Discrepancies generally are less than one percent.

CUMULATIVE PRODUCTION --

Sum of (1) the estimated crude production for the current year, and (2) the actual production for each of the prior years; however, this cumulative production is subject to the qualifications outlined in the definition of Production.

In addition to these "standard" definitions of what crude oil is, how much is calculated to have been discovered in reservoirs known to date, how much has been produced, how much remains to be produced with certainty, and the ultimate total of past and future production under existing technological and economic conditions, a few other terms must be added to describe the status of crude oil presently known to exist but not considered recoverable with certainty under present technological and economic conditions. These terms are as follows:

REMAINING OIL-IN-PLACE --

That volume of the original Oil-in-Place that would remain in presently discovered reservoirs after production of Ultimate Recovery and Indicated Additional Recovery is no improved recovery methods nor changed economic conditions come into existence to increase directly or indirectly the recovery efficiency of present-day operations.

POTENTIAL ADDITIONAL RECOVERY --

That volume of Remaining Oil-in-Place that is estimated to become recoverable by improved recovery methods not yet available or available but not yet sufficiently tested for commercial application, but the future development of which is judged to be feasible under future conditions of technology.

Appendix C - continued

UNRECOVERABLE --

That volume of Remaining Oil-in-Place that is considered not to be recoverable under any foreseeable technological conditions.

ENHANCED RECOVERY --

That volume of crude oil above and beyond Ultimate Recovery that would be recoverable as a consequence of (1) hastening the transfer of Potential and Indicated Additional Recovery to Proved Reserves (as a result of accelerated evaluation of known but untested recovery methods), and (2) transfering Potential Additional Recovery to Ultimate Recovery as a result of developing and implementing future improved recovery methods. The principal source of crude oil for Enhanced Recovery is, of course, that large volume of Remaining Oil-In-Place classified herein as Potential Additional Recovery; therefore, extensive testing and development for operational use of improved recovery methods is inherent in an Enhanced Recovery program.

As shown in Figure 1, certain useful relationships between the various terms describing crude oil reserves can be expressed in simple formulae:

.. Ultimate Recovery = Cumulative Production + Proved Reserves

.. Remaining Oil-In-Place = Original Oil-In-Place - (Ultimate Recovery + Indicated Additional Recovery)

.. Enhanced Recovery = Ultimate Recovery + Compressed Time Factor (Indicated Additional Recovery + Potential Additional Recovery)

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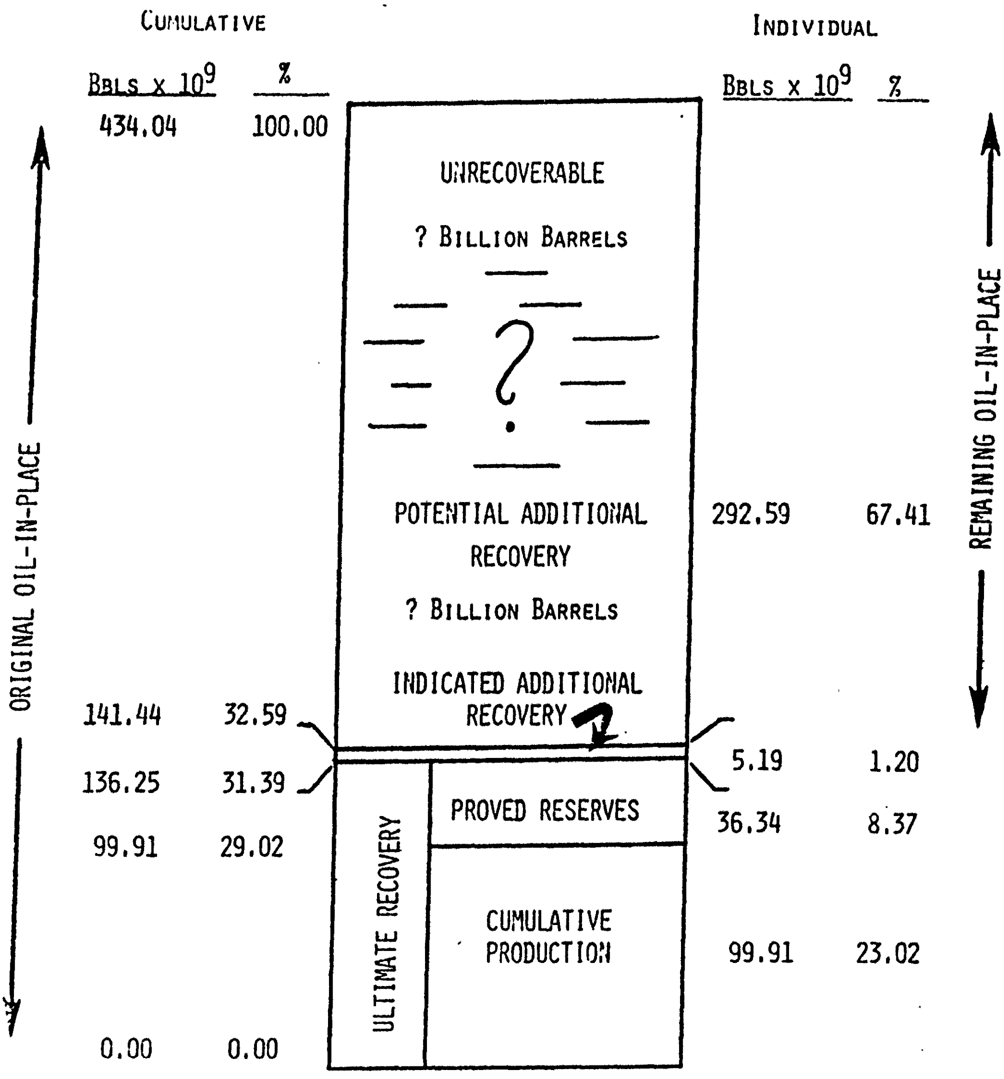
FIGURE 1
CLASSIFICATION OF PRESENTLY KNOWN DOMESTIC CRUDE OIL RESOURCES
(434,038,198 THOUSAND BBLS., ORIGINAL OIL-IN-PLACE)
AS OF 12/31/72



Date from Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1972, Vol. 27, May 1973, AGA, API, CPA

APPENDIX D

DEFINITION OF TECHNICAL TERMS PERTAINING TO NATURAL GAS RESERVE STUDIES

(Source: AGA-API-CPA Reserve Studies)

NATURAL GAS - OCCURRENCE AND RECOVERY

For the purpose of the Committee report, natural gas is defined to be a mixture of hydrocarbon compounds and small quantities of various non-hydrocarbons existing in the gaseous phase of in solution with oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons usually contained in the mixture are methane, ethane, propane, butanes and pentanes, and typical non-hydrocarbon gases which may be contained in reservoir natural gas are carbon dioxide, helium, hydrogen sulphide, nitrogen, etc.

The portions of the reservoir hydrocarbon gas recovered in liquid form in surface separators or plant facilities are reported as natural gas liquids. The statistics on natural gas reserves and production reported by the Committee take into account the shrinkage of the reservoir gas volume resulting from the removal of the liquefiable portions of the hydrocarbon gases and the reduction of volume due to the exclusion of non-hydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

Natural gas is found in underground rock formations which are usually sedimentary in origin. The natural reservoirs are composed of porous rock which provide space for accumulation of hydrocarbons. Economically recoverable quantities of the strata have resulted in the formation of traps which terminate underground migration and cause accumulations of hydrocarbon fluids and gases. Under reservoir conditions, natural gas and the liquefiable portions thereof occur either in a single gaseous phase in the reservoir or in solution with crude oil and are not distinguishable at that time as separate substances. Natural gas is classified by the Committee in two categories based on the type of occurrence in the reservoir, as follows:

1. Non-associated gas is defined as free natural gas not in contact with crude oil in the reservoir.

2. Associated-Dissolved gas is the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with the crude oil (dissolved).

Appendix D - Continued

Associated gas is free natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir at original reservoir conditions.

Production of associated gas usually affects to some degree the ultimate recovery of crude oil by reduction of the gas cap volume and loss of reservoir pressure. Where the production of associated gas from gas wells does not have a significant effect on the crude oil recovery, such associated reserves may be classified as non-associated gas by regulatory body ruling or company operating practice. In such cases this classification is also followed in the report of the Committee.

Where the ultimate recovery of the crude oil is significantly affected by the production of the associated gas both from oil and/or gas wells completed in the reservoir, such gas production is usually limited by regulatory body ruling or company operating practice to assure maximum recovery of crude oil.

In reservoirs containing associated gas and crude oil, the oil, dissolved gas and associated gas may be produced concurrently from the same well bore. This gas is measured and reported by the operator as one volume under the term casinghead or oil well gas. As oil is produced from many reservoirs, pressure is reduced below the saturation pressure of the crude oil and the gas origninally dissolved in the oil is released as free gas in the reservoir. At critical gas saturation of the reservoir, dissolved gas begins to flow and will either be produced with the curde oil, resulting in higher gas oil ratios, or migrate into primary gas caps or form secondary gas caps.

Production and productive capacity of associated and dissolved gas is generally more closely related to the production of crude oil than to the available market for gas. Since only rough estimates for the separation of the production of commingled associated and dissolved gas produced from oil wells can be made as a portion of the dissolved gas may change classification in the reservoir during depletion of the oil reserve, the Committee has combined the reserves and productive capacity of Associated and Dissolved gas into a single category known as Associated-Dissolved. Free gas contained in the reservoir after depletion of the oil reserve is reclassified to the non-associated category. In such cases the gas reserves are determined on the basis of the remaining gas reservoir volume and conditions existing at the time of depletion of the oil reserve.

Appendix D - continued

Volumes of gas reserves are determined by geological and engineering analyses of reservoir data including structural interpretation, well tests, core analysis, pressure production data, gas analysis, etc., available at the time the estimate is made. Recoveries of gas are estimated on the basis of formation evaluation of the reservoir rock, the producing mechanism of the reservoir and pressure production performance.

Due to certain physical and economic conditions a part of the original gas volume in the reservoir is non-recoverable. More specifically these limitations relate to the inability to produce gas because of heterogeneity of the reservoir, gas trapped in the reservoir due to water influx and the inability to economically produce gas because of depleted reservoir pressure. Since the energy which causes gas to flow from a reservoir is derived from the pressure at which the gas exists in the reservoir all of the gas originally contained in the reservoir cannot be produced in economic quantities within any reasonable time. The quantities which are recoverable during the economic life of a reservoir are quite high, several times more than in the case of crude oil. This higher recovery is to be expected because of the difference in viscosity of gas and crude oil and the fact that gas has less tendency to wet the reservoir rock and remain in situ.

In view of the small quantities of unrecoverable gas left in a reservoir during its economic productive life, the change in nature of the hydrocarbons as they are produced and the fact that gas recoveries cannot be increased by improved recovery techniques successfully applied to crude oil, no effort is made herein to report any data on the reservoir space originally occupied by the mixture of gaseous hydrocarbons which evantually are recovered in part as natural gas and in part as natural gas liquids.

NATURAL GAS LIQUIDS

Natural gas liquids are those hydrocarbons in the reservoir natural gas which are separated from the natural gas as liquids either in the reservoir through the process of retrograde condensation or at the surface through the process of condensation, absorption or adsorption or other methods in field separators, scrubbers, gas processing plants and cycling plants. Generally such liquids consist of propane and heavier hydrocarbons expressed in stock tank barrels and are commonly referred to as condensate, natural gasoline and liquefied petroleum gases. Where hydrocarbon components lighter than propane are recovered as liquids these components are also included in the natural gas liquids reserves and production statistics. Natural gas liquids reserves are calculated by the use of a factor applied to the total volume of recoverable gas. Such factor, usually

Appendix D - continued

expressed in stock tank barrels per million cubic feet of gas, is based on the recovery efficiency of installed or planned processing facilities. Such factors may be judged from laboratory gas analyses adjusted to surface processing facility efficiency or obtained from actual plant or separator production statistics. The calculation of proved recoverable reserves of natural gas liquids takes into consideration the effect of retrograde condensation in the reservoir where applicable.

If no information is available as regards plans for processing of gas known to contain liquefiable hydrocarbons, recoveries used in the calculation of reserves are based on separator yields or formation tests.

Natural gas liquids reserves are classified on the basis of the type of occurrence of the gas in the reservoir; that is non-associated and associated-dissolved.

PROVED RESERVES

The Committee's definition of proved reserves defines the current estimated quantity of natural gas and natural gas liquids which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Reservoirs are considered proved that have demonstrated the ability to produce by either actual production or conclusive formation test.

The area of a reservoir considered proved is that portion delineated by drilling and defined by gas-oil, gas-water contacts of limited by structural deformation or lenticularity of the reservoir. In the absence of fluid contacts, the lowest known structural occurrency of hydrocarbons controls the proved limits of the reservoir. The proved area of a reservoir may also include the adjoining protions not delineated by drilling but which can be evaluated as economically productive on the basis of geological and engineering data available at the time the estimate is made. Therefore, the reserves reported by the Committee include total proved reserves which may be in either the drilled or the undrilled portions of the field or reservoir.

In general, the definitions of proved reserves contained in Technical Report No. 1, "Definitions for Petroleum Statistics", of the A.P.I. have been followed in this report. It should be noted that in order to maintain a consistent continuing series, gas in underground storage is included in the total gas reserves in this report. Anyone desiring a value for gas in storage may obtain such by subtraction.

Appendix D - continued

Attention is called to the fact that natural gas is a mixture of hydrocarbon compounds and small quantities of various non-hydrocarbons. In most cases the quantities of non-hydrocarbons are de minimis and do not affect the marketability of the gas. In such cases no reduction in volume for the theoretical removal of such non-hydrocarbons has been made herein. In any reservoir where the quantity of non-hydrocarbons is sufficient to render the particular gas unmarketable an appropriate reduction in the reservoir gas volume has been made to cover the exclusion of such non-hydrocarbons.

ULTIMATE RECOVERY OF GAS RESERVES

Ultimate recovery of gas and natural gas liquids reserves are estimates of the total quantity of such proved reserves which will ultimately be produced from a reservoir as determined by the interpretation of current geological and engineering information and under prevailing economic and operating conditions. Adjustments to estimates of ultimate recovery of gas reserves brought about by new information from additional drilling or reservoir production performance are recorded under extensions and revisions in the reserves reporting. The current estimate of ultimate recovery of gas reserves is the sum of the cumulative production and the remaining recoverable reserves.

DISCOVERIES

Discoveries are defined as proved reserves in newly discovered fields and newly discovered reservoirs in old fields. New reservoir discoveries include proved reserves in new segments of reservoirs that are separated from the previously proved productive area by faulting, lenticularity of the reservoir, or other subsurface discontinuity. Reserves of multi-reservoir fields, included in the new field discovery category, reflect the reserves of all reservoirs proved during the discovery year of the field. New discoveries seldom are delineated or fully developed during the year of discovery. Therefore, the year-end reserves estimates of discoveries generally represent only a part of the reserves that ultimately will be assigned.

Subcommittees are not necessarily aware of or have access to the subsurface information for all new discoveries at the time reserve estimates are prepared. This is especially true if a discovery is made late in the year for which a report is being prepared or when competitive situations relating to open acreage dictate that the subsurface information be held proprietary.

Appendix D - continued

EXTENSIONS TO RESERVES

A discovery in one year normally is delineated by the drilling of both extension and development wells during subsequent years. Drilling usually continues until the productive limits of the field or reservoirs are defined. Increases in the proved area of reservoirs result in appropriate adjustments to estimates of recoverable reserves and such changes are recorded under extensions. Changes resulting from a reduction in the estimate of the proved area are recorded under revisions.

Appendix B

Communications Received by the Committee Expressing an Interest in these Hearings

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U.S. SENATE,
COMMITTEE ON RULES AND ADMINISTRATION,
Washington, D.C., November 30, 1973.

Hon. MIKE GRAVEL,
New Senate Office Building,
Washington, D.C.

DEAR MIKE: I applaud your foresight in conducting hearings concerning the establishment of a trust fund to finance research and development.

As you are aware, I have introduced two bills in this session of Congress related to these subjects and am enclosing copies of these bills along with statements made at their introduction.

I should like very much to have these two bills included in the record of hearings completed yesterday by your Subcommittee on Energy.

If I can assist you in any way in furthering this approach to solving our energy crisis, please let me know.

Sincerely,

MARLOW W. COOK,
U.S. Senator.

[From the Congressional Record, Nov. 13, 1973]

By Mr. Cook (for himself, Mr. Baker and Mr. Bartlett):

S. 2694. A bill to establish an Energy Research, Development, and Demonstration Administration, and to reorganize, consolidate, and supplement within it, Federal responsibility, authority, funding, and financing for conducting a national program for scientific research, development, and demonstration in energy and energy-related technologies designed to resolve critical energy shortages. Referred to the Committee on Interior and Insular Affairs.

Mr. COOK. Mr. President, I am co-sponsor of S. 1283, introduced by Senator Jackson, an energy conservation measure. On review, however, I find that this bill makes no permanent requirements for funding, thus leaving it to Congress to appropriate at any level of funding after the first year, or at no level of funding at all.

Second, it fragments the research as follows:

Coal gasification, $6 million per year for 10 years.

Coal liquification, $7,500,000 per year for 12 years.

Geothermal, $8 million for 15 years.

Advanced power cycle development, $6,500,000 per year for 10 years.

Shale oil development, $5 million per year for 8 years.

Each category has its own corporation and functions independently of the others. On reflection then, the Jackson bill has two serious shortcomings:

First. No trust is established, and funding is thus left to succeeding Congresses.

Second. Separate corporate structures to accomplish the same end is cumbersome, and will not work.

We in this country solved our highway problems with the highway trust—no one doubts that this would never have been accomplished without such a trust.

R. & D. in the energy field will never solve the problems of this Nation without the essentials of a uniform facility to attack the problem and a specific energy trust to allow such a massive program to unequivocally meet a deadline of absolute accomplishment.

Therefore, Mr. President, on July 13 of this year for myself, Senator Robert Byrd and Senator Howard Baker, I introduced S. 2167, a bill to accelerate energy research and development by providing adequate funding over a continuing period of time through the creation of an energy research and development fund. The fund would draw its support from those moneys received by the Federal Government from its lease sales of public lands on the Outer Continental Shelf. I reasoned that as it was the shortage of energy which now enhanced the value of these public assets, this new revenue should in turn be used to find relief to the energy problem itself. I still believe that this reasoning is sound and am more than ever convinced that we will never achieve our R. and D. goals by year to year financing and must adopt some type of trust fund concept. However, there is good argument for broadening the base of this fund by including receipts from Federal lease sales and all other sales or grants of development rights of energy sources on Federal lands.

It has now been 4 months since I introduced this bill and while I have been promised by the chairman of the Senate Interior Committee that hearings will be held at an early date, this date has as yet not been set.

In my original concept I envisioned that the fund would be managed and coordinated by the Interior Department. However, in my introductory remarks, I recognized that new organizational concepts were being considered and suggested that should the President's reorganization reach fruition, that there may be a new office better suited for this purpose.

In his address to the Nation last Wednesday, the President put forward several programs to deal with the immediate energy problems we face today. I support his intent and applaud the rapid action being taken by the Interior Committee to develop the necessary legislation to implement these programs. However, as necessary as these programs are, they are all in the form of a fire fighting stop gap nature and do not address the long-term problem which this Nation must solve.

One program advanced by the President is of particular interest to me and this is the creation of an Energy Resource and Development Administration to control the Nation's efforts in this area. The idea is not new as it is found in the President's earlier program to create a Department of Natural Resources. What is new is the suggestion that we remove R. & D. from the proposed department and create a new independent administration. I think this is sound and I support it.

The President has compared the need for such an effort to the Manhattan project of World War II, which made this Nation the major nuclear power at that time. He also compared this need to the space program of the 1950's which made America the first nation to put a man on the Moon.

I might say there is one that he forgot, Mr. President, and that is that when World War II started, we all thought there was not going to be an automobile in the country that could get any more rubber tires.

It took this Nation 1 year to come up with synthetic rubber, and the only thing we care about rubber trees for today is that they give somebody shade somewhere in the world.

As the President expressed it:

"Whenever the American people are faced with a clear goal and they are challenged to meet it, we can do extraordinary things."

This then is the backdrop for the initiation of "project independence." However, much as I agree with the stated objectives of energy sufficiency by 1980, I am not convinced that the proposal as now being considered can attain this goal. I still hold that we need the energy trust fund. I believe that we need an independent agency to manage this fund and insure that we direct our efforts to programs ranging from the exotic—such as wind and tidal or ocean current power, to the realizable—such as coal gasification and liquefaction—whether our goal is energy self-sufficiency by 1980 or 1985, this Nation's efforts must be wide-ranging and broad in scope. We must not overlook any possibility, however remote or far fetched it may seem.

Accordingly I am today introducing a bill which will accomplish these long-range goals and at the same time incorporate the vital trust fund concept contained in S. 2167. I go one step further, because I do not think that we can reach our goals by research and development alone. I believe that we must include the all important demonstration step in the process.

From my own personal experience I have found that when the R. & D. phase of energy production has been reached there is not adequate provision to support the demonstration phase so necessary to prove or disprove the R. & D. scale model. I suggest that with the creation of the Energy Research Development and Demonstration Administration—ERDDA—supported by adequate trust fund we have a fighting chance of locking our energy problems.

I ask unanimous consent that the bill along with the brief explanation attached be printed at the conclusion of my remarks. I solicit the support of my colleagues and urge that the Senate take prompt action to effect this legislation.

There being no objection, the bill and explanation were ordered to be printed in the Record, as follows:

S. 2694

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That this Act may be cited as the "Energy Research, Development, and Demonstration Administration Act."

TITLE I

STATEMENT OF FINDINGS AND DECLARATION OF PURPOSE

SEC. 101. The Congress hereby finds—

(a) The nation is currently suffering a critical shortage of environmentally acceptable forms of energy.

(b) A major reason for this energy shortage is our lack of an aggressive research, development, and demonstration (referred to hereinafter as "research and development," in accordance with Section 117) effort to develop a national capability for energy self-sufficiency by proper utilization of our large reserves of domestic fossil fuels, nuclear fuels, and geothermal energy, and the potentially unlimited reserves of solar power, nuclear, and other unconventional sources of energy.

(c) Many current uses of our limited basic energy resources, including the conversion of basic energy to an alternate form are highly inefficient.

(d) Current levels of funding by the Federal Government for energy research and development are inadequate and too fragmented to develop a program of the scope needed to insure efficient use of existing sources and to identify and develop the most technically, environmentally and economically feasible methods for utilizing energy from domestic resources.

(e) The capital requirements of a total energy research and development program of the magnitude needed are beyond the means of private sources.

(f) The nation's critical energy problems can be timely solved only if a national commitment is made now to accord the highest priority, to dedicate the necessary financial resources, and to enlist our unequalled scientific and technological capabilities to meet the national energy needs, conserve vital resources, and protect the environment.

SEC. 102. (a) The general welfare, the common defense, and security urgently require and it is Congress' purpose here to undertake a national commitment to resolve the energy shortages and provide the means for achieving a national capability for energy self-sufficiency through socially and environmentally acceptable methods for producing, conserving, and utilizing all forms of energy.

(b) To effectuate that commitment it is Congress' purpose to consolidate and strengthen existing and initiate new Federal programs for energy research and development in an Energy Research, Development, and Demonstration Administration, established hereinbelow and authorized and charged with exercising central responsibility for policy planning, coordination, support, and management of research and development programs, including commercial-sized demonstration plants, and respecting all forms of energy sources.

(c) The Congress further declares and finds that it is in the public interest that responsibility for all Federal energy research and development programs be transferred to the Energy Research, Development, and Demonstration Administration, and that this transfer be effected in an orderly manner assuring adequacy of technical and other resources necessary for the performance of such programs.

TITLE II

ESTABLISHMENT AND ORGANIZATION OF ENERGY RESEARCH, DEVELOPMENT, AND DEMONSTRATION ADMINISTRATION

SEC. 103. There is hereby established, as an independent establishment of the executive branch of the Government of the United States, the Energy Research, Development, and Demonstration Administration (hereinafter referred to as the "Administration" or "ERDDA").

BOARD OF GOVERNORS

SEC. 104. (a) The management and direction of all the affairs and interests of ERDDA shall be vested in a Board of Governors (hereinafter referred to as "the Board" or "the Governors"), composed of 15 members.

Eight of the Governors shall be Government officials, as follows:

1. As Chairman of the Board, the official designated by the President as having primary responsibility for energy policy (subject to Senate confirmation if not already confirmed for his primary office);
2. The Director of the National Science Foundation;
3. An Assistant Administrator of the National Aeronautics and Space Administration, designated by the Administrator of that Administration;
4. An Assistant Secretary of Defense, designated by the Secretary of Defense;
5. A member of the Atomic Energy Commission (proposed hereinbelow to be renamed the "Nuclear Energy Commission"), designated by that Commission;
6. A member of the Federal Power Commission, designated by that Commission;
7. A member of the Council on Environmental Quality, designated by that Council;
8. The Administrator of ERDDA, appointed to that position in accordance with Section 107(b) below.

Seven Governors shall be appointed by the President with the advice and consent of the Senate, as follows:

1. A person with high qualifications and responsibilities in the coal industry whose appointment shall be made from a list of recommendations by the principal national organizations representing the coal industry;
2. A person with high qualifications and responsibilities in the nuclear power industry whose appointment shall be made from a list of recommendations by the principal national organizations representing the nuclear power industry;
3. A person with high qualifications and responsibilities in the natural gas industry whose appointment shall be made from a list of recommendations by the principal national organizations representing the natural gas industry;
4. A person with high qualifications and responsibilities in the petroleum industry whose appointment shall be made from a list of recommendations by the principal national organizations representing the petroleum industry;
5. A person with high qualifications and responsibilities in the electric industry whose appointment shall be made from a list of recommendations by the principal national organizations representing the electric industry;
6. A representative from the public at large with high qualifications and responsibilities for environmental concerns; and
7. A representative from the public at large with high qualifications and responsibilities for consumer concerns.

(b) The terms of the government members of the Board shall coincide with their terms in the offices here qualifying them to serve on the Board. The terms of the seven non-government members shall each be for 4 years subject to prior removal by the President, for cause, except that in order to provide staggered terms, the terms of 2 initial Governors, designated by the President, shall be for 3 years, the terms of 2 shall be for 2 years, and the term of 1 shall be for 1 year. Any Governor appointed to fill a vacancy occurring before the expiration to fill a vacancy occurring before the expiration of the term for which his predecessor had been appointed shall serve for the remainder of such term. Each Governor shall be reimbursed for travel and reasonable expenses incurred in attending meetings of the Board.

(c) 1. The Board shall meet quarterly and on call.

2. Vacancies in the Board, as long as there are sufficient members to form a quorum, shall not impair the powers of the Board.

3. The Board shall act upon majority vote of those members who are present, and any eight members present shall constitute a quorum for the transaction of business by the Board; except that a favorable vote of an absolute majority of the Governors in office shall be required for the approval of annual budgets, and for the appointment, removal, and setting of compensation for the Administrator and Deputy Administrator.

ADMINISTRATOR; DEPUTY ADMINISTRATOR

SEC. 105. The Administrator of ERDDA, appointed pursuant to Subsection 107(a) below, shall serve as the Chief Executive Officer of the Administration, in accordance with Subsection 107(c) below. The Deputy Administrator, appointed under Subsection 107(a) below, shall be the alternate Chief Executive Officer. He shall act for and exercise the powers of the Administrator during his absence or disability.

GENERAL COUNSEL; ASSISTANT ADMINISTRATORS

SEC. 106. There shall be within the Administration a General Counsel, and such number of Assistant Administrators as the Board shall consider appropriate. The General Counsel and the Assistant Administrator shall be appointed by, and serve at the pleasure of the Administrator.

TITLE III

FUNCTIONS

SEC. 107. (a) The Board shall appoint the Administrator of ERDDA from a list of people recommended by the National Science Foundation, the National Academy of Science, and the National Academy of Engineering as highly competent to administer the important and complex energy research and development responsibilities of ERDDA. The Board shall also appoint the Deputy Administrator, and it shall have the power to remove the Administrator and the Deputy Administrator, and it shall fix their pay and terms of service.

(b) The Board may delegate its authority to the Administrator under such terms, conditions, and limitations, including the power of redelegation, as it deems desirable, and it may establish such Committees as it determines appropriate to carry out its functions and duties; such delegations shall be consistent with other provisions of this Act, shall not relieve the Board of full responsibility for carrying out its duties and functions, and shall be revocable by the Board in its exclusive judgment.

(c) The Administrator, as Chief Executive Officer of the Administration, shall be responsible to the Board for implementation of this Act and administration of ERDDA. He shall present an annual budget to the Board of Governors for their review and approval. After the Board has approved a budget, the Administrator may obtain specific moneys within it, from the fund established in Section 114 hereinbelow, by notice to the Secretary of the Treasury that such moneys are needed as of a certain date to carry out the program and budget approved by the Board.

(d) The Administration shall exercise central responsibility for policy planning, budgeting, initiation, coordination, support, and management of research and development programs respecting all forms of energy sources, including but not limited to those specified in Subsection (e) below. It shall be responsible for assessing the requirements for research and development in regard to various forms of energy sources in relation to near-term and long-range needs, for policy planning, and for budgetary and expenditure control to meet those requirements, for retaining, supporting, and where needed, strengthening effective existing programs, and for initiating new programs as needed for the optimal development of all forms of energy sources, from research through commercial-sized demonstrations, for providing appropriate priority and balance among nuclear, fossil fuel, geothermal, solar, and other energy research and development responsibilities, for managing such programs, for terminating them when their purpose has been accomplished or when they are no longer feasible, and for disseminating information resulting therefrom.

(e) The Administration shall have all the authority incidental, necessary, or appropriate to implementing its responsibilities, including without limitations, authorization:

1. to ensure that full consideration and adequate support is given to advancing energy research and development of efficient and environmentally acceptable energy sources, technologies, and techniques including but not limited to:

(i) coal gasification;
(ii) coal liquefaction;
(iii) solvent refined coal;
(iv) improved extraction methods and *in situ* conversion of fuels;
(v) advanced power cycle development;
(vi) shale oil development;
(vii) geothermal energy;

(viii) thermally-actuated heat pumps;
(ix) fuel cells and other direct conversion methods;
(x) solar energy;
(xi) hydrogen as an energy form;
(xii) nuclear breeder processes;
(xiii) fusion processes;
(xiv) magnetohydrodynamics;
(xv) use of agricultural products for energy;
(xvi) utilization of waste products for fuels;
(xvii) cryogenic transmission of electric power;
(xviii) electrical energy storage methods;
(xix) alternative to internal combustion engines;
(xx) wind power;
(xxi) tidal power; and
(xxii) ocean current and thermal gradient power;

2. to prescribe such policies, standards, criteria, procedures, rules, and regulations as it deems necessary or appropriate.

3. to enter into such contracts and agreements, including grant agreements, with public agencies and private organizations and persons; to make payments therefor (in lump sum or installments, and in advance or by way of reimbursement, and with necessary adjustments on account of overpayments and underpayments).

4. to engage in joint projects of a research, developmental, and demonstration nature with public agencies and private organizations or individuals in the organizational form deemed appropriate, and to perform services with or for them on matters of mutual interest, the cost of such projects or services to be apportioned equitably by the Administration.

5. to acquire any of the following described rights if the property acquired thereby is for use by or for, or is useful to, the performance of functions vested in the Administration:

(i) copyrights, patents, and applications for patents, designs, processes and manufacturing data;

(ii) licenses under copyrights, patents, and applications for patents;

(iii) releases, before suit is brought, for past infringement of patents or copyrights; and

(iv) use of Federal lands (except lands preempted for other use by Federal statutes) which contain energy sources which ERDDA determines are necessary to carry out its research and development functions and programs. The responsible officials of such other departments or agencies which have jurisdiction over Federal lands are hereby authorized and directed to make such lands available to ERDDA under terms and conditions promulgated by them to protect the environment and other resource values of lands involved.

6. to make special studies concerning matters within the special competence of the Administration; to prepare from the records of the Administration special compilations, lists, bulletins, or reports; to furnish transcripts or copies of such studies, compilations, and other records; to provide copies of charts, maps, or photographs, and to provide services incident to the conduct of the regular work of the Administration. The administration shall require payment of the actual or estimated cost of such special work in accordance with regulations prescribed by the President.

7. to exercise, in relation to the functions transferred herein, to the extent necessary or appropriate to perform such functions, any authority or part thereof available by law, including appropriations Acts, to the official or agency from which such functions were transferred.

(f) The Administration shall utilize or acquire the facilities of existing Federal scientific laboratories engaged in energy research and development; it shall also establish and operate additional facilities and test sites; and it shall utilize such services of contract agencies as it considers necessary to effectuate the purposes of this Act.

(g) The Administrator shall, as soon as practicable after the end of each fiscal year, submit a Report to the Board, and the Board shall submit a Report to the President for transmittal to the Congress, on the activities of the Administration during the preceding fiscal year, with a full accounting of receipts and expenditures, projects terminated and initiated, and plans and progress made in developing new energy supply and in attaining the capability of energy self-sufficiency from domestic resources.

(h) The President, in the ninth year after the effective date of this Act, shall report to the Congress his evaluation of progress under it and his recommendation for continuance of the Federal energy research and development programs.

TITLE IV

TRANSFERS

SEC. 108. There are hereby transferred to and vested in the Administration such Federal energy research and development functions and programs as are essential to ERDDA's fulfilling its obligations under this Act. Without limitation, such transfer shall include:

(a) All energy research and development functions and programs of the Atomic Energy Commission and of the Chairman and members of the Commission except those pertaining to nuclear weapons or military use of nuclear power. The Atomic Energy Commission's research and development functions related to such military purposes shall be transferred to the Department of Defense, and the Secretary of Defense and ERDDA shall establish a special liaison committee to provide coordination, cooperation, and economy between the Department of Defense and ERDDA as to their respective research and development programs.

The remaining functions of the Atomic Energy Commission shall continue as provided in Section 115 below.

(b) All energy research and development functions and programs of the Secretary of the Interior, the Department of the Interior, and officers and components of that Department.

(c) The energy research and development functions and programs of such other Federal departments or agencies, including without limitation those in the Departments of Commerce. Transportation, Housing and Urban Development, and those in independent agencies such as the General Services Administration, the National Aeronautics and Space Administration, the National Science Foundation, and the Tennessee Valley Authority, as in ERDDA's judgment are necessary or appropriate for it to fulfill its responsibilities under this Act.

(d) Authority for reviewing and coordinating all other energy research and development functions and programs in Federal departments or agencies in the Executive Branch.

(e) Unexpended balances of appropriations, authorizations, allocations, and other funds relating to the functions transferred hereby to ERDDA shall be transferred as determined by the Director of the Office of Management and Budget in accordance with Section 109 below and with Section 202 of the Budget and Procedures Act (31 USC 581(c)).

SEC. 109. (a) During the transition of transfers every effort shall be made to not in any way impede or impair the progress of current Federal energy research and development programs.

(b) Transfer of nontemporary personnel shall not cause any such employees to be separated or reduced in grade or compensation for one year after such transfer.

TITLE V

SAVINGS PROVISIONS

SEC. 110. All orders, determinations, rules, regulations, permits, contracts, certificates, licenses, and privileges which have been issued, made, granted, or allowed to become effective by the President, any Federal department or agency or official thereof, or by a court of competent jurisdiction, in the performance of functions which are transferred by this Act, and which are in effect at the time this Act takes effect, shall continue in effect according to their terms until modified, terminated, superseded, set aside, or revoked by the President, the Administrator, or other authorized officials, a court of competent jurisdiction, or by operation of law.

SEC. 111. (a) The provisions of this Act shall not affect any proceedings pending at the time it takes effect before any department or agency, or component thereof, functions of which are transferred by the Act, but to the extent such proceedings relate to functions so transferred, they shall be continued. Orders

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shall be issued in such proceedings, appeals taken therefrom, and payments made pursuant to such orders, as if the Act had not been enacted; and orders issued in any such proceedings shall continue in effect until modified, terminated, superseded, or revoked by a duly authorized official, by a court of competent jurisdiction, or by operation of law. Nothing herein shall be deemed to prohibit the discontinuance or modification of any such proceeding under the same terms and conditions and to the same extent that such proceeding could have been discontinued if the Act had not been enacted.

(b) Except as provided in Subsection (d)—

1. the provisions of this Act shall not affect suits commenced prior to the date this Act takes effect, and

2. in all such suits proceedings shall be had, appeals taken, and judgments rendered, in the same manner and effect as if the Act had not been enacted.

(c) No suit, action, or other proceeding commenced by or against any officer in his official capacity as an officer of any department or agency whose functions are transferred by the Act shall abate by reason of enactment of the Act. No cause of action by or against any department or agency, functions of which are here transferred, or by or against any officer thereof in his official capacity shall abate by reason of the enactment of this Act. Causes of actions, suits, actions, or other proceedings may be asserted by or against the United States or such official as may be appropriate and, in any litigation pending when the Act takes effect, the court may at any time, on its own motion or that of any party, enter any order which will give effect to the provisions of this Act.

(d) If, before the date on which this Act takes effect, any department or agency, or officer thereof in his official capacity, is a party to a suit involving any function of such department, agency, or officer transferred by this Act to the Administration, then such suit shall be continued as if this Act had not been enacted, with the Administration substituted.

(e) Final orders and actions of any official or component in the performance of functions transferred by this Act shall be subject to judicial review to the same extent and in the same manner as if there had been no transfer. Any statutory requirements relating to notices, hearings, action upon the record, or administrative review that apply to any function transferred hereby shall apply to the performance of those functions by the Administration, or any officer or component.

SEC. 112. With respect to any function transferred by the Act and performed after its effective date, reference in any other law (including reorganization plans) to any department or agency or any officer or office the functions of which are so transferred shall be deemed to refer to the Administration or officials thereof in which this Act vests such functions.

SEC. 113. Nothing herein shall be construed to limit, curtail, abolish, or terminate any function of the President which he had immediately before the effective date of the Act; or to limit, curtail, abolish, or terminate his authority to perform such function; or to limit, curtail, abolish, or terminate his authority to delegate, redelegate, or terminate any delegation of functions.

TITLE VI

FUNDING

SEC. 114. (a) There is hereby established in the Treasury of the United States a trust fund to be known as the Federal Energy Research, Development, and Demostration Trust Fund (referred to herein as the "fund"). The fund shall consist of such amounts as may be credited or appropriated to it as provided in this section, and moneys so credited or appropriated are hereby made available to ERDDA for carrying out the purposes of this Act including the administration thereof, without fiscal year limitations.

(b) Commencing with the fiscal year ending June 30, 1974, and each fiscal year thereafter, all revenues (except so much thereof as may be already obligated under the provisions of other legislation such as Section 2(c)(2) of the Land and Water Conservation Fund Act of 1965 (16 U.S.C. 4601–5) due and payable during each such fiscal year to the United States for deposit in the Treasury as receipts from Federal lease sales of all energy sources, as well as royalties and other revenues derived from operations on, or the use of, such Federal leases, shall, up to $2,000,000,000, be credited to the fund.

(c) In addition to the moneys credited to the fund pursuant to Subsection (b) of this section, there is authorized to be appropriated to the fund for the fiscal year ending June 30, 1974, and each fiscal year thereafter, such amount as is necessary to make the income of the fund $2,000,000,000 for each such fiscal year.

(d)(1) It shall be the duty of the Secretary of the Treasury to manage the fund and (after consultation with appropriate officials of ERDDA) to report to the Congress not later than the first day of March of each year on the financial condition and the results of the operations of the fund during the preceding fiscal year and on its expected condition and operations during each fiscal year thereafter. Such report shall be printed as a Senate and House document of the session of the Congress to which the report is made.

(2) It shall be the duty of the Secretary of the Treasury to invest such portion of the fund as is not, in his judgment, required to meet current withdrawals. Such investments may be made only in interest-bearing obligations of the United States or in obligations guaranteed as to both principal and interest by the United States. For such purpose such obligations may be acquired (A) on original issue at the issue price, or (B) by purchase of outstanding obligations at the market price. The purpose for which obligations of the United States may be issued under the Second Liberty Bond Act, as amended, are hereby extended to authorize the issuance at par of special obligations exclusively to the fund. Such special obligations shall bear interest at a rate equal to the average rate of interest, computed as to the end of the calendar month next preceding the date of such issue, borne by all marketable interest-bearing obligations of the United States then forming a part of the public debt; except that where such average rate is not a multiple of one-eighth of 1 per centum, the rate of interest of such special obligations shall be the multiple of one-eighth of 1 per centum next lower than such average rate. Such special obligations shall be issued only if the Secretary of the Treasury determines that the purchase of other interest-bearing obligations of the United States, or of obligations guaranteed as to both principal and interest by the United States on original issue or at the market price, is not in the public interest.

(3) Any obligation acquired by the fund (except special obligations issued exclusively to the fund) may be sold by the Secretary of the Treasury at the market price, and such special obligations may be redeemed at par plus accured interest.

(4) The interest on, and the proceeds from the sale or redemption of, any obligations held in the fund shall be credited to and form a part of the fund.

TITLE VII

NUCLEAR ENERGY COMMISSION

SEC. 115. (a) The Atomic Energy Commission shall retain its functions pertaining to uranium and thorium reserve assessment, and its functions pertaining to the licensing and related regulatory functions of the Chairman and members of the Commission, the General Counsel, and other officers and components of the Commission performing such functions, which functions, officers, and components are not included in the transfer to the Administrator by section 108 above.

(b) The Atomic Energy Commission is hereby renamed the Nuclear Energy Commission.

TITLE VIII

EFFECTIVE DATE AND INTERIM APPOINTMENT

SEC. 116. The provisions of this Act dealing with title II (sections 103, 104, 105, and 106) shall take effect on the day of enactment. All other provisions shall take effect thirty days thereafter. Funds available to any department or agency (or any official or component thereof), any functions of which are transferred to the Administration by this Act, may, with the approval of the President, be used to pay the compensation and expenses of any officer appointed pursuant to this subsection until such time as funds for that purpose are otherwise available.

Title IX

DEFINITIONS AND ADMINISTRATIVE PROVISIONS

Sec. 117. (a) As used herein references to:

1. "function" or "functions" include references to duty, obligation, power, authority, responsibility, right, privilege, and activity, or the plural thereof, as the case may be;
2. "perform" or "performance" when used in relation to functions, include the exercise of power, authority, rights, and privileges;
3. "research and development" include all phases of Federal energy research, development, and demonstration, ranging from the conception of scientific and engineering principles appropriate for attaining a particular technological objective through the demonstration of their practical utility on a commercial scale, except to the extent they are or military purposes;
4. "demonstration" refer to that stage of a research and development program which typically follows the pilot plant stage and the objective of which is to establish the commercial feasibility of a particular process before it is put into commercial use;
5. "energy sources" include fossil fuels, geothermal energy, nuclear energy, solar energy, tidal energy, and other unconventional sources of energy;
6. "person" include any individual, association, institution, corporation, or other entity, any state or political subdivision, or agency or institution thereof, and any Federal department or agency;
7. "the Act" or "this Act" refer to the "Energy Research, Development, and Demonstration Act" enacted herein;
8. "the Administration" or "ERDDA" refer to "the Energy Research, Development, and Demonstration Administration" established herein; and
9. "fund" refer to the Federal Energy Research, Development and Demonstration Trust Fund established herein.

Any reference to any provision of law shall be deemed to include, as appropriate, references thereto as now or hereafter amended or supplemented.

(b) The Administrator is authorized to accept, hold, administer, and utilize gifts, and bequests of property, both real and personal, for the purpose of aiding or facilitating the work of the Administration. Gifts and bequests of money and proceeds from sales of other property received as gifts or bequests shall be deposited in the Treasury and shall be disbursed upon the order of the Administrator. Property accepted pursuant to this section, and the proceeds thereof, shall be used as nearly as possible in accordance with the terms of the gift or bequest. For the purpose of Federal income, estate, and gift taxes, property accepted under this section shall be considered as a gift or bequest to the United States.

(c) The Administration shall cause a seal of office to be made of such device as the Board shall approve, and judicial notice shall be taken of such seal.

Title X

SEPARABILITY

Sec. 118. If any provisions of this Act, or the application thereof to any person or circumstance is held invalid, the remainder of the Act, and the application of such provision to other persons or circumstances shall not be affected thereby.

A Bill To Establish an Energy Research, Development, and Demonstration Administration

The attached proposed legislation is based on the conviction that a substantially increased centralized, and sustained energy research and development program, including demonstration, is indispensable to development of the nation's domestic energy sources, and thereby its energy self-sufficiency, through socially and environmentally accepted methods for producing, conserving and utilizing all forms of energy. Accomplishment of this vital effort requires a fresh new organization independent of existing organizations and procedures, and charged with overall and specific accountability for coordination, streamlined administration, and results.

The bill accordingly provides for the establishment of a new independent agency, the Federal Energy Research, Development, and Demonstration Administration ("ERDDA"). Responsibility is consolidated therein for coordinating and administering all existing, and for initiating, coordinating and administering extensive new, energy research and development functions and programs applicable to all forms of energy—except those undertaken for military purposes. Commensurate authority extends from overall policy planning and budget control, to all stages of particular projects, from initial conception through design, construction, operation and maintenance of commercial-sized demonstration plants, such operations to be carried on internally with ERDDA's own facilities, or by suitable arrangement with contract agencies.

A 15-member Board of Governors, composed of Government Officials qualified in energy and energy research and development, and of experts from the private sector, is responsible for overall supervision of ERDDA. The daily operations of ERDDA are to be directed by an "Administrator," who must be outstandingly qualified in those fields, and their management. He will serve as Chief Executive Officer responsible to the Board for carrying out the Board's policies consistent with the objectives and purposes of the Act.

To carry out this effort, the bill provides for funding through a special trust fund composed of receipts from Federal lease sales and all other sales or grants of development rights of energy sources on Federal lands, up to $2 billion a year. The payments to the Federal Government for energy development rights thus earmarked for development of new energy sources would provide the sustained continuity indispensable to a project of this nature.

[From the Congressional Record, July 13, 1973]

STATEMENTS ON INTRODUCED BILLS AND JOINT RESOLUTIONS

Mr. Mr. Cook (for himself, Mr. Robert C. Byrd, and Mr. Baker):

S. 2167. A bill to authorize the Secretary of the Interior to conduct research, development, and demonstration projects in the fields of energy sources and technologies. Referred to the Committee on Interior and Insular Affairs.

Mr. COOK. Mr. President, on Tuesday, July 10, I was pleased to join with my colleagues in a colloquy on the energy problems which this Nation faces. I believe most sincerely that in addition to focusing attention on these problems, we also have to come forward with sensible and workable solutions.

At the conclusion of my statement I again expressed my belief that we must solve our problem by the production and use of our domestic resources. I proposed that we expend every effort to improve our research and development efforts to a degree that we are no longer dependent on a foreign power for our energy fuels. In so doing we could insure our status as a world power.

I referred to the President's second energy statement as well as various pieces of legislation before the Congress.

The President has now concluded that the present program for funding energy R. & D. is not adequate. There are many of us who have held this view for some time and I am pleased to see this new approach the President is now taking. His announcement that $10 billion should be funded for energy R. & D. over the next 5 years beginning in 1975 follows very closely the proposal contained in Senator Jackson's bill, S. 1283, of which I am a cosponsor.

S. 1283 would establish a national program for Research, Development and Demonstration in Fuels and Energy and for the coordination and financial supplementation of Federal energy research and development. The bill would cost $20 billion over a 10-year period.

Mr. President, regardless of the course we decide to follow I believe that the objective can be achieved only if there is assured financing over a continuing period. If we permit the R. & D. program to be dependent on an annual appropriation we most certainly risk attainment of our goal. The question then arises as to how this assured and continued funding can best be provided.

In 1956, when the decision was made to undertake the construction of 40,000 miles of super interstate highways we recognized that in so doing we were tackling the greatest construction project in the history of man. We recognized further that to achieve our goal that we must have assured funding over a continuing period. We realized that we must remove the uncertainties inherent in dependence on annual appropriations. The decision was made by the 84th Congress and President Eisenhower to establish a Highway Trust Fund for this purpose. Public Law 627 came into being. The fund derived its assets from taxes paid on fuels, tread rubber, tires, tubes, buses, trucks, and other highway use sources. In this way the user paid the cost of the highway. We now enjoy a highway network which I question would exist had we not created this fund. As we seek the best solution to funding required R. & D. programs for energy, I think we would do well to consider our previous action.

The requirement exists for assured and continuous funding of our R. & D. program. What better way to provide this funding than the creation of a Federal Energy Research and Development Trust Fund. This fund could act as a repository for funds of a prescribed amount and expenditure could be made from the fund to meet requirements as they occurred over a continuous time period. I suggest a sum of $2 billion would be paid into the fund annually. I would not restrict or require that a specific amount be expended over a fiscal year and would permit the administration to expend the available funds over a continued period to meet requirements. Experience has shown that R. & D. projects usually begin with small initial funding requirements and their requirements over succeeding periods are dictated by their success or failure.

In suggesting $2 billion as an annual sum I realize that this amount is a quantum jump in R. & D. expenditure. For the period fiscal year 1970; fiscal year 1974 only $2.753 billion was funded. These figures were included in the President's first energy message, and I ask unanimous consent that a copy be printed in the record.

There being no objection, the tables, were ordered to be printed in the record, as follows:

FEDERAL ENERGY R. & D. FUNDING

Agency	Fiscal year 1970	1971	1972	1973	1974
Coal: Resources development	30.4	49.0	73.5	94.5	119.9
Production and utilization R. & D. including gasification, liquefaction and MHD:					
DOI, OCR	13.5	18.8	30.3	43.5	52.5
DOI, BOM	13.2	15.4	14.7	19.8	18.1
Mining health and safety research, DOI, BOM	3.7	14.8	28.5	31.2	28.3
Interior central fund (part), DOI					21.0
Petroleum and natural gas	8.8	11.5	12.9	12.8	9.1
Petroleum extraction technology, DOI, BOM	2.7	2.7	3.2	3.1	3.1
Nuclear gas stimulation, AEC	3.7	6.1	7.1	7.2	4.0
Oil shale, DOI, BOM	2.4	2.7	2.6	2.5	2.0
Nuclear fission	283.4	295.2	358.0	412.0	475.4
Liquid metal fast breeder reactor:					
AEC	144.3	167.9	236.0	269.0	320.0
TVA			.2	3.0	3.0
Other civilian nuclear power, AEC	108.5	96.6	86.8	98.0	90.5
Nuclear materials process development, AEC	30.6	30.7	35.0	42.0	61.9
Nuclear fusion	37.5	42.2	52.8	65.5	88.5
Magnetic confinement, AEC	34.3	32.2	33.3	39.6	47.3
Laser, AEC	3.2	10.0	19.5	25.9	41.2
Solar energy, NSF			1.7	4.2	12.2
Geothermal energy	.2	.2	1.4	3.4	4.1
NSF			.7	.7	1.4
DOI-GS	.2	.2	.7	2.5	2.5
DOI-BOM				.2	.2
Electrical generation, transmisison and storage		1.3	2.2	4.9	4.1
NSF		.5	1.3	2.4	.9
DOI		.8	.9	1.0	1.0
AEC				1.5	2.2

Control technology (stationary sources)			28.6	38.1	47.5
Air pollution control technology, EPA	19.8	17.4	24.5	29.5	21.5
SOX removal, TVA			1.1	3.0	18.0
Thermal effects:					
EPA	.8	.6	.7	1.0	1.0
AEC	1.5	1.8	2.3	4.6	7.0
Miscellaneous			6.3	6.9	11.0
Systems and resource studies, NSF			4.4	5.3	5.3
Energetics research, NSF			1.9	1.6	1.7
Interior central fund (part), DOI					4.0
Total research and development	382.4	419.2	537.4	642.3	771.8
AEC	326.1	345.3	420.0	487.8	574.1
EPA	20.6	18.0	25.2	30.5	22.5
NSF		.5	10.0	14.2	21.5
DOI	35.7	55.4	80.9	103.8	132.7
TVA			1.3	6.0	21.0

Agency codes: AEC—Atomic Energy Commission; DOI, BOM—Department of the Interior, Bureau of Mines; DOI, GS—Department of the Interior, Geological Survey; DOI, OCR—Department of the Interior, Office of Coal Research; NSF—National Science Foundation; TVA—Tennessee Valley Authority.

Mr. Cook. In analyzing these figures it is interesting to note that $2.110 billion or 76.6 percent of this total was funded for atomic energy. The remaining sum—$642 million was divided over all other R. & D. projects related to energy.

I take no issue with the amount funded for atomic energy as I believe that we will benefit from this important program. I do regret the paucity of funds—$642 million—which has been shared over the past 5 years by programs related to: coal, oil, gas, geothermal, solar, and other miscellaneous systems. We must correct this deficiency. I believe that the establishment of a fund in the amounts suggested will meet this requirement.

Let us consider the source of these funds. I again suggest the user approach. However, rather than revenue from the tax placed on the user I suggest that we utilize the revenue from the assets of the user. In this instance the user is most certainly the public—you and I. And the asset of which I speak is our public land and more specifically that public land which lies on the Outer Continental Shelf—OCS. For many years we had these assets but we did not consider them to be of any great value because the supply far exceeded the demand.

Today we find that these OCS assets have indeed increased in value. The irony in this increase is that it has come about by an energy shortage, particularly oil and gas, which threatens to destroy many of our much more tangible and recognizable assets.

The revenue comes to us through the lease bonuses paid by the energy industry for permission to explore for and produce oil and gas from our public land. The use of funds collected by the Government in our interest from the energy industries for the use of our land would seem to me to be a most logical source of funds for Government funded R. & D. programs to solve our energy problem. Projections for the adequacy of such funds seem most favorable.

I have received information concerning the OCS lease sales and request that it be printed in the Record at this point.

There being no objection, the table was ordered to be printed in the Record, as follows:

OUTER CONTINENTAL SHELF LEASE SALES

Year	Leased tracts	Acres	Bonus (millions)	1st-year rentals (millions)
1968	197	934,167	$1,346	$3.0
1969	40	114,283	112	1.1
1970	136	591,040	944	2.1
1971	11	37,222	96	.4
1972	178	826,195	2,251	2.5
1973 [1]	104	600,000	1,598	1.8
Total	666	3,102,907	6,347	10.9

[1] Preliminary estimates. O. & G. Journal, June 25, 1973. In addition a lease sale of about 800,000 acreas is scheduled for December 1973.

Mr. COOK. If we take the period of calendar year 1968–72 and the first few months of 1973 we find that $6.347 billion have been collected in lease bonus payment by the energy industry. This is considerably more than was expended for the R. & D. during a similar period. I also remind the Congress that the President has announced his intention to increase by threefold our previous lease sales and has announced one additional lease sale of considerable size for December of this year. Judging from the acreage involved the revenue from this sale could well exceed $1 billion. This total sum for this year would be over one-half billion in excess of that required to support the funding for the proposed trust fund.

Mr. President, on July 10, 1973, I announced my intention to propose legislation to provide the necessary funds for energy research and development. I am today introducing a bill for Senator BAKER of Tennessee, Senator ROBERT C. BYRD of West Virginia, and myself to establish in the Treasury of the United States a trust fund to be known as the "Federal Energy Research and Development Trust Fund" and ask unanimous consent that the text be printed in the RECORD at the conclusion of my remarks.

The ACTING PRESIDENT pro tempore. Without objection, it is so ordered.

(See exhibit 1.)

Mr. COOK. Commencing with the year ending June 30, 1974, and each fiscal year thereafter, all revenues up to $2 billion except as otherwise obligated, due and payable during each such fiscal year to the United States for deposit in the Treasury as miscellaneous receipts under the Outer Continental Shelf Lands Act shall be credited to the Fund. In the unlikely event the leasing program does not generate sufficient funds: sufficient funds would be authorized as necessary to make the annual income of the Fund $2 billion.

In announcing his cosponsorship of this bill Senator Baker suggested that an attempt be made to broaden the base of contributions to this Fund and that one possible method might be incorporated in a user's utility tax. He further stated that he intends to offer something concrete along these lines in the near future. I welcome Senator BAKER's suggestions as I believe that it has considerable merit. It follows very closely the intent of the bill in that the Fund would be supported by the user. I believe that this matter could be considered in detail by the committee to which it is referred, and I so recommend. Certainly we would want to make an ample provision for the necessary funds.

It is my intent that the Secretary of the Interior or, if the Congress so chooses, the Secretary of the Department of Energy and Natural Resources, would use the Fund to conduct research, development, and demonstartion projects.

I might suggest at this point, Mr. President, that it might even be considered, in the event the trust were to be established to the full extent, that if it were necessary, the Federal Government could even go into the business, as we did in the atomic energy crisis and as we did in the NASA crisis, as we did prior to World War II and during the course of World War II, and that if it is necessary it might even be considered that it would be prudent to the extent that the Federal Government would go into the business of the establishment of refineries, the establishment of pipelines, or whatever was necessary to solve and create a logical energy program for the United States, so that we would not be dependent on foreign sources.

Therefore, Mr. President, on this basis, the Government could enter into contracts and agreements with any person for conduct by such persons of these projects in all fields of energy sources and technologies.

Mr. President, the 93d Congress is making progress in solving our energy problems. I urge that it continue this progress and support the passage of this bill.

EXHIBIT 1—S. 2167

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That the Secretary of the Interior is authorized, utilizing moneys in the Fund established by section 2 of this Act, to conduct research, development, and demonstration projects in, and to enter into agreements with any person for the conduct by such person of research, development, and demonstration projects in, the fields of energy sources and technologies. In carrying out the provisions of this Act, the Secretary of the Interior is authorized to make grants, and to enter into contracts, leases, or other arrangements.

(b) As used in this section, the term—

(1) "energy sources" includes fossil fuels, geothermal energy, nuclear energy, and solar energy, tidal energy, and unconventional sources of energy; and

(2) "person" includes any individual, association, institution, corporation, or other entity, any State or political subdivision, or agency or institution thereof, and any Federal department or agency.

SEC. 2. (a) There is hereby established in the Treasury of the United States a trust fund to be known as the "Federal Energy Research and Development Trust Fund" (hereafter referred to in this section as the "Fund"). The Fund shall consist of such amounts as may be appropriated or credited to it as provided in this section. Moneys credited or appropriated to the Fund pursuant to this section are hereby made available to the Secretary of the Interior for carrying out the purposes of this Act without fiscal year limitations.

(b) Commencing with the fiscal year ending June 30, 1974, and each fiscal year thereafter, all revenues (except so much thereof as may be obligated under the provisions of section 2(c)(2) of the Land and Water Conservation Fund Act of 1965 (16 U.S.C. 4601–5)) due and payable during each such fiscal year to the United States for deposit in the Treasury as miscellaneous receipts under the Outer Continental Shelf Lands Act shall, up to $2,000,000,000, be credited to the Fund.

(c) In addition to the moneys credited to the Fund pursuant to subsection (b) of this section, there is authorized to be appropriated to the Fund, for the fiscal year ending June 30, 1974, and each fiscal year thereafter, such amount as is necessary to make the income of the Fund $2,000,000,000 for each such fiscal year.

(d)(1) It shall be the duty of the Secretary of the Treasury to manage the Fund and (after consultation with the Secretary of the Interior) to report to the Congress not later than the first day of March of each year of the financial condition and the results of the operations of the Fund during the preceding fiscal year and on its expected condition and operations during each fiscal year thereafter. Such report shall be printed as a Senate document of the session of the Congress to which the report is made.

(2) It shall be the duty of the Secretary of the Treasury to invest such portion of the Fund as is not, in his judgment, required to meet current withdrawals. Such investments may be made only in interest-bearing obligations of the United States or in obligations guaranteed as to both principal and interest by the United States. For such purpose such obligations may be acquired (A) on original issue at the issue price, or (B) by purchase of outstanding obligations at the market price. The purposes for which obligations of the United States may be issued under the Second Liberty Bond Act, as amended, are hereby extended to authorize the issuance at par of special obligations exclusively to the Fund. Such special obligations shall bear interest at a rate equal to the average rate of interest, computed as to the end of the calendar month next preceding the date of such issue, borne by all marketable interest-bearing obligations of the United States then forming a part of the Public Debt; except that where such average rate is not a multiple of one-eight of 1 percent, the rate of interest of such special obligations shall be the multiple of one-eight of 1 percent next lower than such average rate. Such special obligations shall be issued only if the Secretary of the Treasury determines that the purchase of other interest-bearing obligations of the United States, or of obligations guaranteed as to both principal and interest by the United States on original issue or at the market price, is not in the public interest.

(3) Any obligation acquired by the fund (except special obligations issued exclusively to the Fund) may be sold by the Secretary of the Treasury at the market price, and such special obligations may be redeemed at par plus accrued interest.

(4) The interest on, and the proceeds from the sale or redemption of, any obligations held in the Fund shall be credited to and form a part of the Fund.

Mr. ROBERT C. BYRD. Mr. President, will the Senator yield?

Mr. COOK. I yield.

Mr. ROBERT C. BYRD. Mr. President, I congratulate my distinguished friend from Kentucky (Mr. Cook) on the foresight that he is demonstrating in introducing this legislation.

We in this country have been living in an energy-cheap era. We have been wasteful, we have been thoughtless, and we have lacked the vision and foresight that we should have shown, and are paying for it dearly now and will continue to do so. For too long administrations—Democratic and Republican—have failed to budget sufficient moneys for energy research, and particularly in connection with coal. The problems we are having in the 1970's derive in great measure from the fact that we failed to act in the 1960's to provide adequate funds for coal, oil, and gas research.

As a member of the Senate Appropriations Committee, for 15 years I have sought to secure increased appropriations for coal research. When I was a Member of the other body, and served there with my distinguished friend the junior Senator from Montana (Mr. Metcalf)—who is now presiding over this august body—we sought to establish an Office of Coal Research, and after several years of persistent efforts, Congress enacted legislation to provide such an office. But the administrations, as I say, both under Democratic leadership and under Republican leadership, have in my judgment failed over the years to provide the necessary funding requests to adequately deal with the energy problem through research.

It is true, as the distinguished Senator from Kentucky pointed out, there has been a considerable amount of money spent in the nuclear energy field, but coal, the most bountiful fossil fuel resource we have in this country, has consistently come up on the low end of the totem pole. There has long been a serious imbalance in funding for research in the energy field. Over the years, I have tried to add moneys for coal research in appropriation bills. It has been like trying to wring water out of a dry towel—a drop here and a drop there—we get a little money from the subcommittee, and then the full committee. It comes to the Senate. It goes to conference and there it gets cut in half. It has been a severe trial to try to add moneys for coal research when the administration fails to request sufficient funds for such in the budget. The very best we can do is too little.

I believe that the able Senator from Kentucky has come up with an idea here which, patterned after the highway trust funds which have been so successful and without which we would not today have the broad network of excellent interstate highways in this country, will provide adequately for the funding of energy research. I want to congratulate him. I appreciate his adding my name as a cosponsor. I trust that we will have the support of other Senators for the legislation..

I hope that the legislation the Senator from Kentucky has introduced will receive speedy hearings and expeditious action.

Mr. COOK. Mr. President, I want to thank the distinguished Senator from West Virginia. Through the efforts of the distinguished Senator from West Virginia in his position as a Senator from West Virginia and his position on the Appropriations Committee, the funds for the Office of Coal Research this year are $113 million, which is almost twice the amount the administration requested.

The point I am trying to make is that the Senator from West Virginia has helped me ever since I came here. The Institute for Surface Mining, established at Berea College in Kentucky, is the only institute of its kind in the United States. We have been able, by hard work, to get it funded at an approximate level of $300,000 a year, yet it has been used in almost every coal State in the United States, including the State of the distinguished Senator from Montana (Mr. Metcalf), now the Presiding Officer of the Senate.

I might also say that it was through the efforts of the senior Senator from West Virginia, in approximately 1955 or 1956, that the first money was put in the budget for coal gasification and the institute was established and started work on coal gasification. Yet because it was a budget item that had to be renewed on a year-to-year-to-year basis, within 2 years it was dropped from the budget.

The project was stopped. We lost all that time between 1956 and now on coal gasification, coal liquefication, and desulfurization of coal.

Look where we are now. I might say that both Senators from West Virginia (Mr. Randolph and Mr. Robert C. Byrd) have been working on this matter far longer than I have. So that I can only say there is only one way to get rid of this frustration that we have to fight every year, and that is by the establishment of a trust so that we know there can be continuing and ongoing funds available, so that we do not have to fight every year for coal research to try to solve the various problems that need to be faced in the energy field.

Mr. ROBERT C. BYRD. I again compliment the Senator from Kentucky. It has indeed been frustrating to try to squeeze out a dollar here and a dollar there for coal research. I was able through great effort to secure moneys to establish a pilot plant to produce high-octane gasoline at Cresap, in Marshall County, W. Va. It was a pilot plant, costing $10 million to $12 million. Its purpose originally was to conduct research in the effort to produce high-octane gasoline from coal. I think we achieved our goal. At least it was proved that such gasoline can be produced from coal at prices that are almost competitive with other fuels. But the plant has been in mothballs now for some time. Yet, the country needs a low-sulfur-content fuel oil and this plant could be utilized for that purpose. The Department of the Interior is supporting the use of this plant for that purpose. I feel that it soon will be put to that use.

But we continue to spend billions of dollars for oil coming to our country from overseas which affects our balance of payments adversely, which affects our balance of trade adversely, whereas if we could spend a comparatively few pennies here, if we had spent a comparative few dollars 10 years ago, a few dollars in comparison with the high cost of importing oil coming into this country now, we would not now have such a balance-of-payments deficit, and we would not have to lean on other countries for the energy so important to our security. We would not have the problems in our own country with respect to blackouts, brownouts, and the other energy shortages that we are confronted with today and which we will be increasingly confronted with for awhile.

I congratulate the Senator from Kentucky again. He has demonstrated tremendous foresight and I hope that the Senate will act favorably and soon on this legislation.

Mr. COOK. May I associate myself with the remarks of the Senator from West Virginia.

Mr. President, it is an amazing situation we find ourselves in in this country that 6 percent of the world's population is now using between 35 percent and 40 percent of the world's fossil fuel resources. We now use 5 million barrels a day of imported crude oil. It does not take anyone long to figure out that a 42-gallon barrel—all we have to do is take a 42-gallon barrel and multiply it 5 million times, and if we continue at the rate we are increasing now, and we are increasing our utilization by 4.5 percent a year, that means that unless we do something between now and 1985, we will be importing into this country 15 million barrels of crude oil a day.

We cannot let that happen to this Nation. We have got to have a program. It is amazing that we have watched the increase in prices of various fuels and various items of fuel, yet we find out that one of the increases is a direct result of the competitive element of bidding for leases from the U.S. Government and one of the major costs that has to be put on the books by the companies is the fantastic result of the millions and millions of dollars that they have to bid for the leases and the money goes into the Treasury instead of into a trust fund to solve our energy problems.

Mr. ROBERT C. BYRD. It is a repetition of the old story, "For want of a nail, the shoe was lost. For want of a shoe, the horse was lost. For want of a horse, the rider was lost."

Mr. COOK. I thank the Senator from West Virginia.

The ACTING PRESIDENT pro tempore. The time of the Senator has expired.

Mr. STEVENS. Mr. President, I have a feeling that one of the reasons we have the opposition to the off shore drilling is that the States that are on the shore with the proposed activity have no interests. I have not seen the Senator's proposal and I wonder whether it contains any concept of payments to the States, affected by the increased activity offshore as we do in connection with the development of public lands or development of the forests in counties where they are located.

Mr. COOK. To answer the Senator's question bluntly, it does not. But we gave that serious consideration, and I would hope that the Senator from Alaska would pursue it. If he feels that there should be a particular percentage, because of the tug of war that has gone on through the years between the Federal Government and the respective States relative to offshore drilling, I hope he would collaborate with this Senator at least, in trying to find a percentage or trying to find a formula by which a percentage of the trust would be utilized for the State of Alaska, the State of Florida, the State of Louisiana, the State of Texas, the respective eastern shore States and Western shore States, to resolve the problem that the Senator from Alaska presents.

Mr. STEVENS. I would be happy to work with the Senator from Kentucky on that.

In connection with the developments of the offshore drilling in the Cook Inlet, where there are now a series of platforms that are producing oil and gas from under the Cook Inlet, we can demonstrate fully the impact of those operations on both the State and what we call the borough, and what the Senator would call the county governments, and the city governments in the area; the cost of schools; increased roads, docks, and everything else associated with that development—all of which comes out of those local governments—and they have no associated income if the drilling is outside the State's jurisdiction. I would be pleased to work with the Senator on that.

I do not think Maryland or the east coast is going to allow drilling off the east coast until they can see that it is in their financial interest to do so, because of the fantastic cost associated today in connection with environmental protection.

I think the Senator has a good proposal, and I am happy that I was here when he presented it. But I think we are going to have to do something to protect the interests of the States and local governments involved.

Mr. COOK. I thank the Senator from Alaska for raising the point, because we did raise it in our discussions. At that stage of the game, we had the information we really wanted for the establishment of the trust. I say to the Senator that we had no way of pinpointing a percentage. We had no way of determining logically and with sound reasoning an equitable formula. I think we can move in that direction, and we should. I am delighted that the Senator from Alaska raised that point.

Mr. STEVENS. I thank the Senator.

STATEMENT ON ENERGY RESEARCH POLICY

(By J. Hilbert Anderson, Consulting Engineer, and vice president, Sea Solar Power, Inc.)

All of the furor about the energy crisis has stimulated thousands of suggestions. Each proposer of a solution or partial solution is sure that his idea is most important to the overall effort. As a result we have myriads of roads to travel but no direction or mileage signs.

It is now time to take a hard look at the economics of our possible sources of energy, and decide which ones we can really afford to develop.

We, in the United States have been blessed with enough energy and ingenuity so that power has been ridiculously cheap. As late as ten years ago we were promised nuclear power "too cheap to meter". Now that the mirage has disappeared we can get down to some honest hard work to solve the problem.

What is the real measure of what we can afford to pay for energy? When we tried to analyse this on a logical basis we suddenly realized that our real objective is simply to produce power cheaper than animal power. If we can't produce power cheaper than animals can produce it, then we will obviously go back to an animal powered society. Whether the animals are human or not, has no bearing on the case.

Probably the best measure of the cost of animal power is the horse, our traditional source of power, prior to the industrial revolution, and a source that is still in use. A draft horse currently costs about $300.00. If we say that one horse produces one horsepower, or three quarters of a kilowatt, then the cost of a horsepowered plant would be $400.00 per kilowatt. Since a horse can work only eight hours per day, and perhaps 250 days per year, the percentage of time worked, or the load factor is only 22.8%. The fuel cost is the food cost for the horse, which we are told is approximately $1.25 per day. If the horse produces 1490 kilowatt hours per year and the cost of food is $456.00 per year, then the cost of fuel is 30.6 cents per kilowatt hour. If we assume the fixed charges for maintaining a horse are 15% per year, then this adds $60.00 per year to our cost, or 3.0 cents per kilowatt hour. Our total cost of power is then 33.6 cents per kilowatt hour. As an approximation we can say that any source of power that will cost more than 34 cents per kilowatt hour is hardly worth developing.

Now, let us look at costs of presently used sources of power, and compare them with estimated costs of proposed potential sources of power. This should tell us where we should really spend our development effort.

Our first chart, Fig. 1 shows the approximate range of installed costs for various types of power plants. Much of this data was taken from information supplied by the National Science Foundation.

The first three bars on the left of the chart show costs of conventional fossil fueled plants, ranging from a minimum of $200.00 per kilowatt for gas fired plants to $400.00 for coal plants.

The next bar shows Sea Thermal Power. This means power generation from the warm solar heated surface waters of the ocean. The costs of $300 to $500 per kilowatt were estimated by the National Science Foundation. Our own original estimated costs were $160 per kilowatt.

Geothermal power is shown with plant costs from $100 to $500 per kilowatt. The wide variation will depend largely on the temperature and corrosiveness of the water or steam supply, and the type of cooling system used.

Wind power is estimated to cost from $200 to $600 per kilowatt, and these estimates seem to be based on sound experience.

Nuclear power plant costs range from a little more than $400 per kilowatt for plants presently being completed to about $1000 for the projected breeder reactor plants.

Solar thermal plants collect the sun's energy on man made collectors in desert locations, convert it to heat energy, which in turn drives a more or less conventional power plant. Cost estimates run from $900 to $1900 per kilowatt, depending upon how optimistic one is about the cost and efficiency of solar collectors.

PV Earth represents direct conversion of the sun's energy to electricity by photovoltaic cells arranged in huge arrays. The upper figure of $70,000 represents costs based on present prices of photovoltaic cells. Proponents say that if cell efficiency can be improved considerably, and if manufacturing costs can be reduced by a factor of more than 100 to 1, then costs might come down to $300 per kilowatt.

PV Space uses photovoltaic collectors in a huge array placed in a synchronous orbit as a space station. This station then transmits power to an earth station by microwave transmission. One advantage is that solar radiation is far more intense outside the earth's atmosphere, thereby boosting cell output. This is already demonstrated by the synchronous satellite presently in use. The other major advantage is that power output is held constant and is developed for about 23 hours of the day vs. only about 10 hours per day for a similar station on earth. Present cost estimates show a price of $200,000 per kilowatt. Proponents hope that costs might come down to $500 after many years of research and manufacturing development.

The cost of power depends not only on the plant cost, but also on how much of the time power can be produced, commonly called the load factor. The fixed cost for power can be represented simply by the formula:

$$\text{Fixed cost/kwh} = \frac{.15 \times \text{capital cost/kw}}{\text{load factor} \times 8760}$$

The capital cost of 15% is a fairly common figure, including interest, taxes, maintenance, and profits.

To the fixed cost for power we must add fuel costs. Solar, hydro, wind, and tidal power plants require no fuel. All others require fuel. The fuel cost for power can be represented by:

$$\text{Fuel cost/kwh} = \frac{3413}{\text{Efficiency}} \times \frac{\text{Fuel cost}}{\text{Btu}}$$

The total power cost produced at the plant is then the sum of the fixed cost and the fuel cost.

Fig. 2 is a chart of power costs from various types of plants, plotted against percent load factor. The diagonal lines show the plant costs in dollars per kilowatt. The lower bars show the power cost from the fixed charges, nd the upper bars show the total cost of power with fuel cost added to fixed cost.

The fixed cost for horsepower discussed earlier is plotted at 22.8% load factor, and shown at three cents per kilowatt hour for a capital cost of $400 per kilowatt. Adding the fuel cost of 30.6 cents per kilowatt hour brings the total cost to about 34 cents per kilowatt as shown by the upper bar.

An interesting side light is the cost of power to run our automobiles. This is shown in the inset. The average automobile runs about 10,000 miles per year, and automobile engineers tell us that the actual power usage is about 30 horsepower. At these ratings the load factor is only 3.8% and the capital cost is about $175 per kilowatt, showing a fixed cost of about eight cents per kilowatt hour. Adding the fuel cost brings the power cost up to a total of about 10 cents per kilowatt hour.

It is interesting to note that if we take recently published average automobile running costs of 13 cents per mile the cost also comes out to about 10 cents per kilowatt hour. This merely shows that the public is willing to pay this much for power, if they have to. Note, however, that the cost of power on the automobile or the horse are for power delivered to the user, not power at the plant, as defined in the other cases.

Tidal power plants can operate at a load factor of only 25%. The only large tidal power plant existing is that on the River Rance in France. It cost about $350 per kilowatt. Projected cost for the Passamaquoddy plant proposed for the U.S. were approximately $800 per kilowatt. This would bring power costs to six cents per kilowatt with no fuel cost.

Small wonder that more tidal plants have not been built!

The gas turbine is the cheapest form of fuel fired plant, at costs as low as $125 per kilowatt. However, efficiency is low and fuel prices are very high, so that the current load factor is quite low. This results in a high cost of up to 22 mills per kilowatt hour for gas turbine power. Gas turbine cycle efficiencies can be almost doubled, but this is counteracted by rapidly increasing fuel prices.

PV on earth is shown at a load factor of 33%. This brings presently projected costs to about $3.50 per kilowatt. Since a storage system must be added to these costs to provide power at night the economics look poor indeed.

Solar thermal power will have a low load factor similar to that of PV. Maximum estimated costs of 10 cents per kilowatt hour do not include costs of required energy storage systems. Therefore, the cost will probably be higher than 10 cents shown on the chart.

The hydroelectric power plant cost of $400 per kilowatt was based on the average of a world wide survey published in *Fortune* several years ago. Actual costs ranged from about $200 to $800 per kilowatt. Load factors probably average about 50%, because of large yearly variations in water supply.

The average load factor for nuclear plants has been 60%. Cost of nuclear fuel is quite low, although disposal costs for residual fuel should be added. Based on a fuel cost of about three mills per kilowatt hour added to the fixed costs nuclear power total costs should vary from about 15 mills to about 32 mills.

Wind power is estimated to have a better load factor than that established by nuclear plants. Since wind power has a random load factor, rather than a fixed one like solar power, storage requirements will be much less, and can be lessened largely by means of a wide distribution network. Therefore, the costs varying from seven mills to 17 mills should not have to be increased greatly for storage systems.

Fossil fuel steam plants have a probable load factor of about 70%, although the U.S. average is lower than this. Based on a fuel cost of about three mills per kilowatt hour and the capital costs from $175 to $400 per kilowatt the power cost would vary from about 6.6 mills to 12 mills per kilowatt hour. As fuel costs go up these costs will certainly be higher.

Geothermal plants have an excellent load factor already demonstrated to be over 90%. A load factor of 85% is shown here. Fuel costs are presently a little less than three mills per kilowatt hour. Adding this to the fixed cost charges shows a power cost of five to 12 mills per kilowatt hour. This is presently and will almost surely continue to be one of our lowest cost sources of power available on a large scale.

Sea Thermal Power should have an extremely high load factor, and has a slight advantage over geothermal power in that maximum power output occurs in the summer, when demand is greatest. Therefore we have assumed the load factor to be 90%. Since there is no fuel cost the power cost varies from an estimated three mills to nine mills.

Photovoltaic solar power in space has an advantage of providing power about 23 hours out of 24, so should have a load factor of about 95%. The extreme costs of the equipment rule it out as a practical source of power except as a possibility for the distant future.

The chart says very clearly that of all the possible new sources of power only Wind power, Geothermal power, and Sea Thermal power appear to be clearly economical in competition with present sources. If we accept this as a possibility, then we must ask ourselves what is the potential of each, where is it available, and how soon can we develop it.

The potential for wind power has been estimated by different authorities. Heronemus ("Pollution-Free Energy from Offshore Winds", by W. E. Heronemus, presented to "Marine Technology Society", September 1972) reports the total Northern Hemisphere wind energy at 10^{11} megawatts in winter and 60% of that in summer. The World Meteorological Organization estimates that 2 x 10^7 megawatts of wind power is available at favorable sites. This compares to a total average U.S. usage of 1.76 x 10^5 megawatts in 1970. Obviously the potential is big enough to be worthwhile.

In the case of geothermal power wildly different estimates of the potential are made. Be that as it may, most authorities do agree that there is sufficient potential to be worthwhile, and estimates are rising quite rapidly.

The biggest problem in developing geothermal capacity is that of heat rejection, but new cooling systems now appear to be able to solve that problem, so that a large potential for geothermal power can be realized.

Sea Thermal Power has more potential than we can probably ever use. The Gulf Stream alone has a potential power production capacity of more than 100 times the total U.S. usage.

The possible location of these various sources of power is really not as important as some people seem to think. For example, if I generate Sea Thermal Power in Florida and save a barrel of oil there, then that barrel of oil is available for use in Minnesota. Or if I save a barrel of oil in California by using Geothermal power, then that barrel is available for New York.

Fortunately Wind power, Geothermal power, and Sea Thermal power complement each other very well in their availability. Many favorable wind sites occur in New England and the Midwest. Geothermal hot water occurs on the West coast, Pacific Northwest, Rocky mountains, Gulf coast, Alaska, and Hawaii. Sea Thermal power is readily available close to Florida, Georgia, Puerto Rico, and Hawaii. These three sources can conveniently and economically provide power for practically the entire United States, and eliminate our dependence on foreign oil.

Let us now look at development timing for each of these power sources.

Wind power has been in use for thousands of years. Further development is only needed for large scale planning, better operating efficiency, and manufacturing capability. Small wind power plants are already marketed. Within less than five years we could have many wind power plants operating.

Geothermal power plants are already in operation at 300 MW total capacity. These are natural steam plants. A hot water demonstration plant can be built within one year after site selection and availability of funds. The turbines for such a plant are already built, waiting to be used. Manufacturing capablity is available for rapid construction of these plants. They can be built far more rapidly than nuclear plants.

We could have a Sea Thermal plant within four years after authorization and availability of funds. While there are numerous development problems, they are all of a routine engineering nature, and solutions are virtually assured for all of them. The fastest way to a solution of the problems is simply to build a plant.

It is now clear that we must change direction. Instead of putting nearly all our funds into the development of nuclear energy, we should divert a relatively small amount of this money into Wind power, Geothermal power, and Sea Thermal power. These funds will move us faster toward a solution of our energy problems in less time and at less cost than by any other conceivable path. They will also solve this problem with the complete approval of all those interested in protecting our environment for the good of mankind.

The time for action is *now.*

Further delays and inaction will cost us far more in money and human suffering than the little money that we need spend to complete these developments.

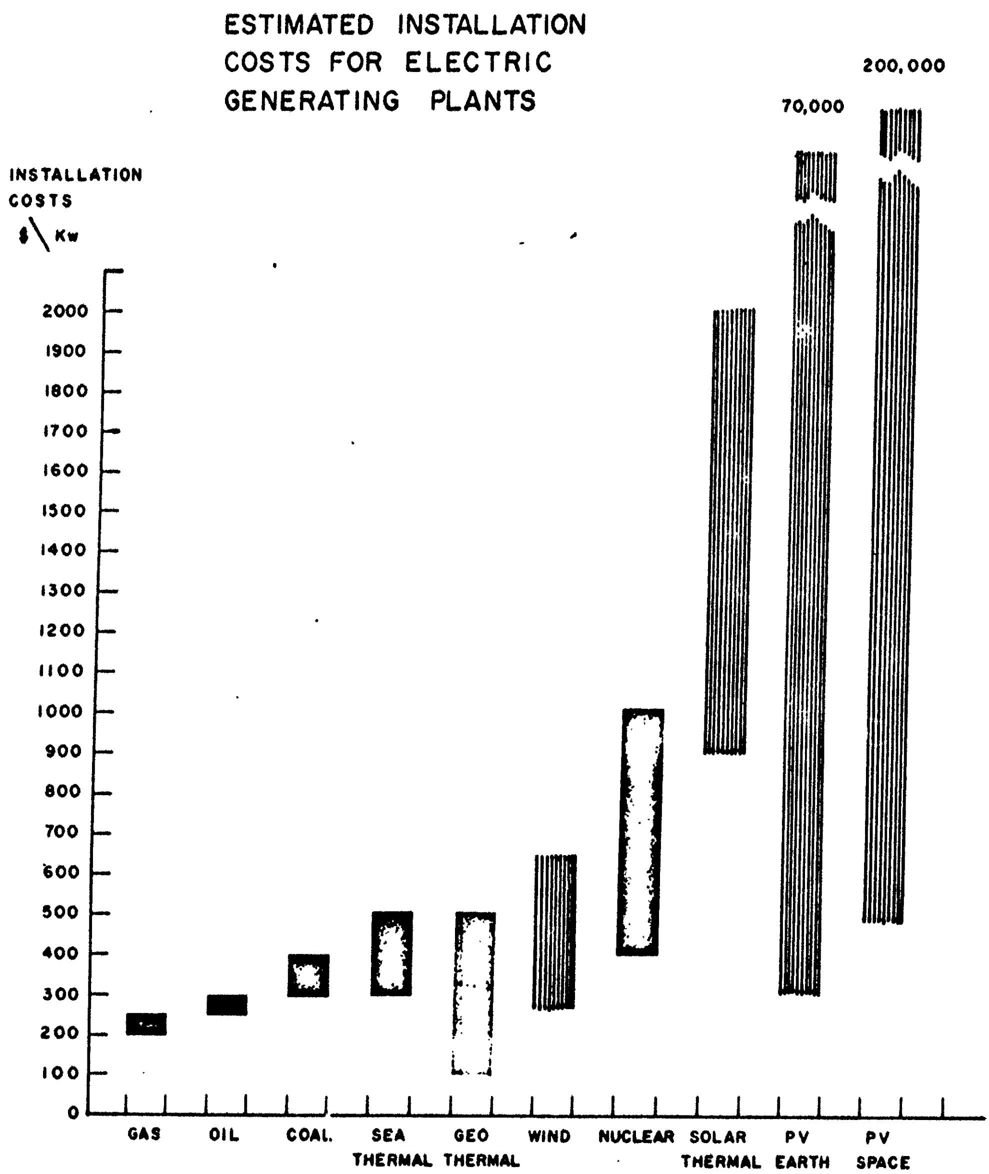
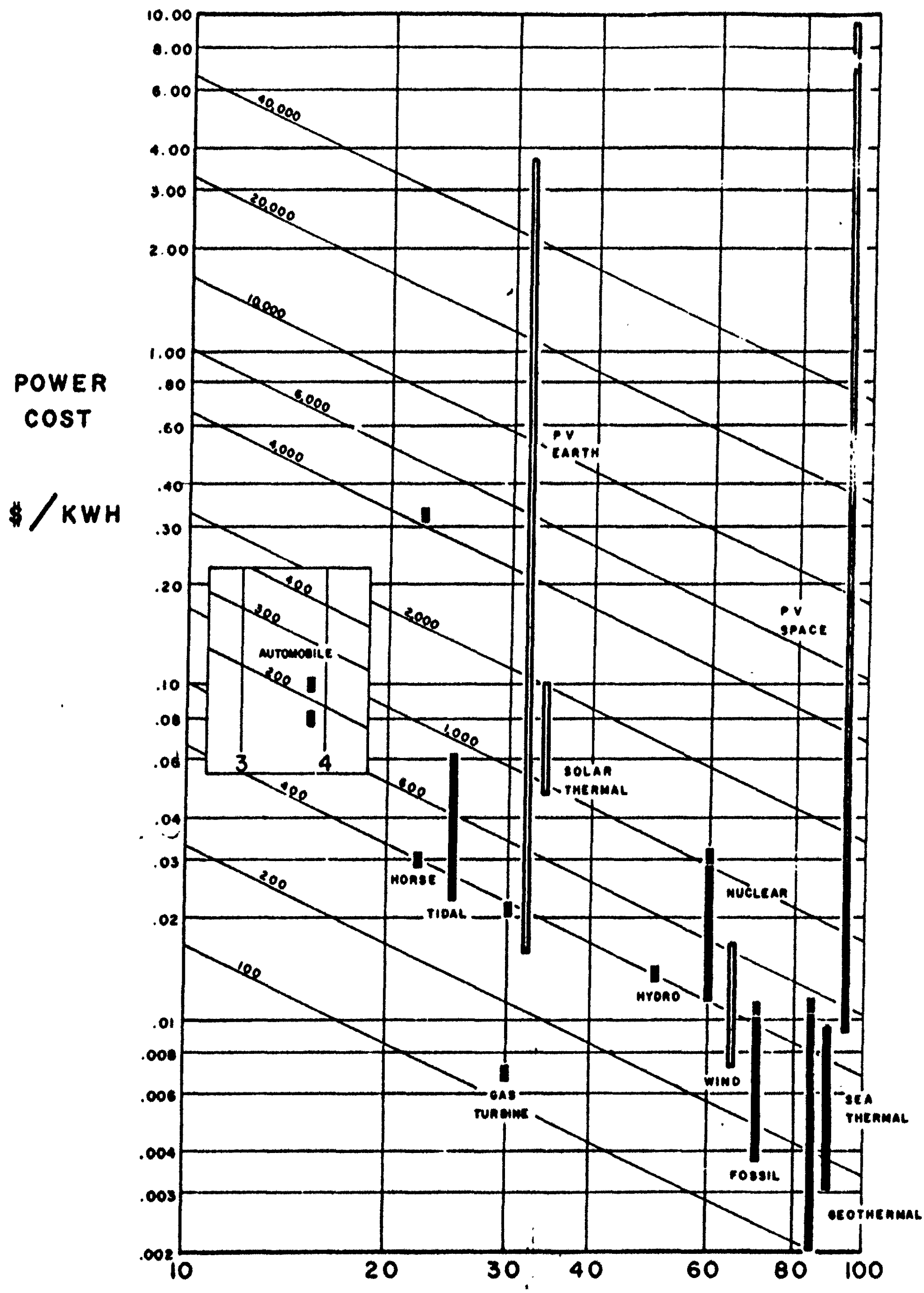


FIG. 1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POWER COST
$/KWH
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300
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100
AUTOMOBILE
3
4
PV EARTH
PV SPACE
SOLAR THERMAL
HORSE
TIDAL
GAS TURBINE
HYDRO
NUCLEAR
WIND
FOSSIL
SEA THERMAL
GEOTHERMAL
10
20
30
40
60
80
100
PERCENT LOAD FACTOR

FIG. 2.

ILLINOIS COLLEGE REPUBLICAN FEDERATION, INC.,
December 10, 1973.

Mr. MICHAEL STERN,
Staff Director, Senate Finance Committee, New Senate Office Building, Washington, D.C.

MR. STERN: It is my wish that this letter be included in this year's hearing record on November 27, 28, 29, of the new Subcommittee on Energy.

We hope that this subcommittee will try to create reasonable incentives for energy conservation and production, and to see that our clean energy options are not neglected. With the help of this subcommittee, now is the time, when everyone is highly interested in energy supplies, to let the people know that the government has knowledge of clean energy alternatives.

With your help, development of clean energy can be implemented at the national and local level. Heat the local school with electric power from wind-driven generators. Run the school bus on clean solar-made methane gas (from leaves, trash, algae, sewage). Heat the school's water with solar water heaters. Help run the local power plant with fuel made from trash. It is clean energy, directly or indirectly.

Some equipment could be improvised this winter. State governments could finance or promote bigger installations in a few years. With government and industry backing, large-scale use of clean energy could begin in the 1970's, instead of the year 2000!!

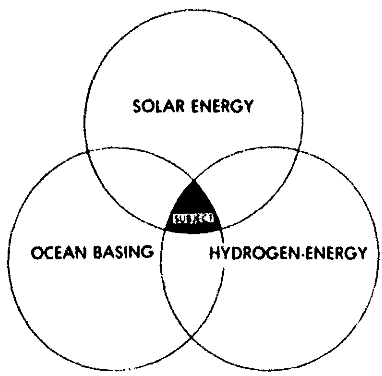
This is the government's opportunity to destroy the myth that clean energy can not help us in the 1970's, and to let the people know that you *do* consider it an acceptable "solution" to the country's future energy supply!!

Sincerely yours,

JEFF BAKER, *Chairman.*

A PROBLEM STATEMENT:

OCEAN BASED SOLAR-TO-HYDROGEN ENERGY CONVERSION MACRO SYSTEM



By

William J. D. Escher

Escher Technology Associates

And

Joe A. Hanson

Oceanic Institute

NOVEMBER 1973

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ETA PT-33

OCEAN BASED SOLAR -TO-HYDROGEN ENERGY CONVERSION MACRO SYSTEM

by WILLIAM J. D. ESCHER and JOE A. HANSON

SUMMARY

This paper is in essence only a "problem statement" or initial conceptualization, in which a potentially important large-scale technological enterprise is addressed: an ocean based solar-to-hydrogen energy conversion facility. It is proposed to use hydrogen as an energy carrier to be delivered to the spectrum of energy-using sectors, instead of electricity, because of hydrogen's advantages of transportability and storability. These make hydrogen and solar energy natural adjuncts.

It is further proposed that the solar-to-hydrogen conversion process be conducted on the open ocean, and not in the traditional desert location. The advantages, we suggest, far outweigh the drawbacks. In addition to well-established marine engineering know-how, we forsee the need for a new class of large ocean stable platforms upon which to base the industrial complex. Fortunately, the basic technology for such is being pursued -- albeit at too modest a pace --by the ocean community.

It is not yet apparent to us what specific solar energy conversion mode, or combination of modes, should be selected among the several direct and indirect techniques available. Economics and available technology will control this choice as illuminated by further study.

In addition to the exportation of hydrogen-energy, in the form of cryogenic liquid hydrogen and oxygen transported in tankers, we believe it highly likely that a number of coproducts can also be profitably supplied by the ocean complex were it appropriately outfitted. Among the possibilities are: sea foods via open ocean mariculture, minerals and chemicals such as salt and fertilizers, and certain finished materials (especially those which are energy-intensive) such as magnesium and aluminum.

ACKNOWLEDGMENT

We wish to acknowledge the long-standing encouragement and patience of Professor William E. Heronemus who was instrumental in developing this paper. He and his staff at the University of Massachusetts assisted us greatly in the draft preparation stage also.

A talk based on this material was presented by one of the authors (Escher) at the Annual Winter Meeting of the American Society of Mechanical Engineers in Detroit on 12 November. This was given before the ocean engineering session chaired by Professors Heronemus and J.G. McGowan. Earlier, both authors previewed their respective contributions at the NSF sponsored Solar Sea Power Plant Conference and Workshop held at the Carnegie-Mellon University, Pittsburgh, 27-28 June.

PURPOSE, SCOPE AND BACKGROUND

In this paper we address a very large-scale technological proposition in the long-range energy planning area. Rather than a really substantive investigation of this proposition, the paper is rather limited; it is more in line with being simply a "Problem Statement". Hopefully, others will be stimulated by the offering to comment on it as such. Possibly an engineering feasibility study can be mounted in time to assess better the potential payoffs suggested here.

As indicated by the paper's title, we will view the possibility of mechanizing a process in which solar energy is used to produce hydrogen (and oxygen) as an energy form from ocean resources. Further, we will stipulate that the process be carried out wholly in an open-ocean based technological complex.

The Venn diagram of Figure 1 depicts this basic proposition:

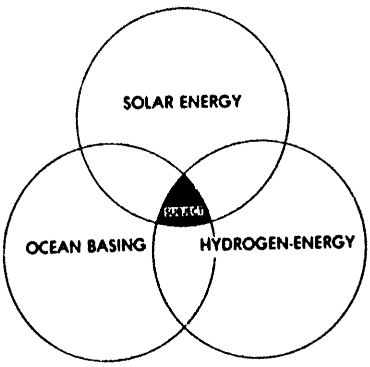
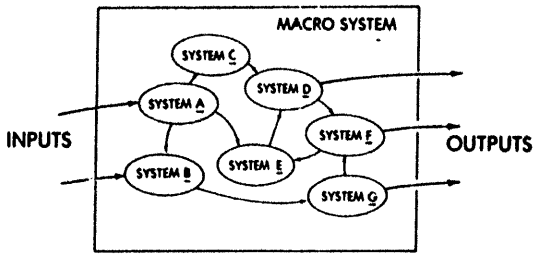


Figure 1

By "macro system" is meant a large-scale and complex technical enterprise which can be helpfully viewed as a "system of systems." Figure 2 represents this general concept pictorially. Using specified inputs, the constituent systems within the macro system interact purposefully to produce the desired outputs.

The paper's scope comprises the four points listed in Table 1. Technical aspects of a generalized model for the subject macro system are discussed with economic factors being only briefly touched upon because of limited information at this stage of the investigation. Specific hardware approaches are suggested, principally for illustrative purposes, and remain provisional pending further system design and analysis. An example is the nominal selection of depth-located electrolyzers and gaseous product storage.

WHAT IS MEANT BY "MACRO SYSTEM"



A PURPOSEFUL ASSEMBLAGE OF MATCHED, INTERACTIVE COSTITUENT SYSTEMS

Figure 2

SCOPE OF INVESTIGATION

- POSTULATE TECHNICAL MODEL
- ILLUSTRATE SPECIFIC HARDWARE APPROACHES
- ILLUMINATE POTENTIAL OF STABLE OCEAN PLATFORMS
- DELINEATE RELEVANT TECHNOLOGIES

Table 1

A central purpose of the paper is the illumination of the applicability of on-going stable ocean platform activities to ocean based enterprises of the type being proposed. Developments of the off-shore oil drilling industry in very large semisubmersible structures are noted in this connection, as are certain oceanographic projects which bear on the feasibility of future sea-based energy/industry complexes.

Finally, a technological "awareness" has been attempted. Where applicable technology for supporting the concepts to be discussed exists, this is noted. Where critical or "enabling" technology can be identified to be in especial need of early research and development support, this is pointed out (see "Concluding Observations.")

The specific macro system concept to be addressed, Figure 3, is an ocean based solar/sea energy conversion concept in which the energy "product" is in the chemical energy of hydrogen.

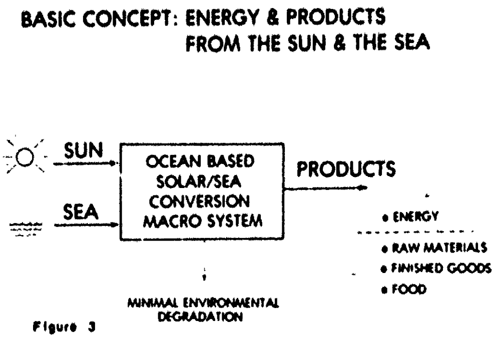


Figure 3

Inputs are two: (1) Solar energy (converted in several possible modes) and (2) the Sea itself, meaning total ocean resources: water, dissolved solids, and marine biota. The principal output is "energy", specifically "hydrogen-energy"; this is defined as hydrogen alone, or the hydrogen-oxygen bireactant pair with the two being processed and handled as a special "energy form".

Other outputs (below the dashed line in Figure 3) or "coproducts" may be forthcoming. Specific examples are: potash, magnesium metal and shellfish. However, these coproducts are viewed as secondary to the primary objective of producing hydrogen-energy.

To the extent that operation of the macro system contributes to local environmental degradation, proven or suspected, these effects must be absolutely minimized by intrinsic design measures. Hence, "minimal environmental degradation" is a fundamental criterion.

In summary, that which is envisioned is a macro system capable of optimally converting solar and ocean resources into hydrogen-energy, a storable, transportable, clean energy form. Secondarily, raw materials, finished goods, foodstuffs and other coproducts may be produced as well in association with energy production. All production is to be accomplished in an open-ocean based facility; a minimum of environmental degradation -- hopefully, none --is stipulated as a basic precept.

Historically, land-based industrial enterprises accomplish the various functions suggested here; one naturally questions such a radical departure as industrial sea-basing. Visions of costly exercises in nautical architecture in a traditionally hostile sea environment are immediately engendered. Indeed, the practicability and overall worthwhileness of the ocean basing approach has to be fundamentally questioned.

Our thesis is that the open ocean may prove to be an entirely logical, technically advantageous and economically appealing location for carrying out the input/output mix (Figure 3) at the large scale level we are considering. Recall, our purview is a long-range future-oriented one.

FUTURE NEED FOR LARGE SCALE SOLAR ENERGY CONVERSION CAPABILITY

The sun, along with hoped-for achievement of controlled thermonuclear fusion and/or success in large-scale extraction of geothermal energy, is the sole identified long-term possibility for meeting the world's ever-expanding energy demand. If we were to be able to stabilize this demand at some fixed level in the future, we would still require these non-fossil sources eventually, for our present fossil-fuel era is innately self-limited in duration.

Among the non-fossil energy sources, this paper focuses on the sun as a unique, logical means of providing energy for future generations of the earth. We make no attempt to defend this thesis, here, however. (See, for example, (1)*)

As suggested, the basic motivation to utilize solar energy stems from the knowledge that our present fossil-fuel era will peak out within 100 years in all probability, with a rapidly decreasing availability of energy from this quarter thereafter. This view has been convincingly supported by a number of authoritative investigations.

That of Elliott and Turner (2) projects the rate of production of world fossil fuels for a total estimated range (conservative to optimistic) of 85 to 226 x 10^{18} Btu. Figure 4, adapted from this reference, reveals a characteristic projection which the authors developed. For a total world resource base of 226 x 10^{18} Btu ("optimistic"), this figure reflects the world production estimates for (1) Fluid fossil fuels (natural gas, oil) alone, and (2) Total fossil fuels based on the assumption that coal gasification and liquefaction conversion processes (at 70 percent thermal efficiency) will be economically developed for widespread use. The fact that the major portion of world fossil fuels are contained in the less-desirable form of coal is clear from the curves (compare areas).

The striking point of Figure 4 which underscores the necessity for rapid development of an unprecedented non-fossil energy supply is this: world production of fossil fuel energy may peak out as early as the 2010 - 2030 time period (the specifics depend on our success in coal fluidization). Unless there is a reliable non-fossil

*Numbers in parentheses refer to references listed at the end of the paper

PROJECTED RATE OF PRODUCTION OF WORLD FOSSIL FUELS

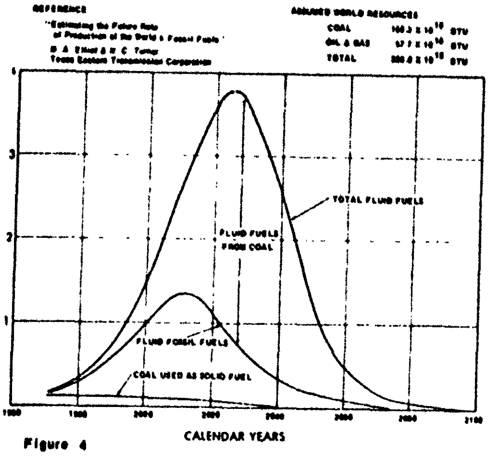


Figure 4

source of energy available at that time to "pick up the load", drastic, even precipitous ramifications to all of the world's industrial nations are predictable. The consistent, perhaps innate, correlation between national energy consumption per capita and gross national product supports this point. Further, the fortunes of developing nations of this time-period will be critically jeopardized since this is traditionally an energy-dependent transition.

Our only alternative non-fossil energy source presently in service is, of course, nuclear fission electrical generation systems. But these are "burner" reactors, able to utilize the limited U-235 isotope. These will have to be supplanted by breeder reactors in order to be able to utilize uranium resources effectively; without the breeder, our nuclear energy sources are quite limited. Our U-235 resources in the U.S. have been assessed at 283×10^{15} Btu @ \$ 8/lb of U_3O_8, and 770×10^{15} Btu @ \$ 15/lb (3). No plutonium recycle was assumed for these estimates from Brookhaven National Laboratory.

For reasons of energy resource limitation, the liquid metal fast breeder reactor (LMFBR) is necessarily projected to surpass non-breeder systems in electricity generation capacity just after the turn of the century (3). Assuming that all of the far more plentiful U-238 can be converted into thermal energy in breeders, the total domestic fission energy resource is very considerably enlarged to an estimated 39×10^{18}(3). This is far from an "unlimited" quantity when the trends of world energy consumption are addressed.

But the breeder reactor is currently only developmental in status; there are a number of basic uncertainties still facing reactor designers. The breeder could turn out to be considerably more limited in its energy contribution to national and world energy budgets than the preceding figures would suggest.

Therefore it is deemed only prudent to seek alternative non-fossil energy sources by means of actively supported research and development programs. Particularly so since the number of these alternatives is actually quite limited: solar, geothermal and thermonuclear fusion. The only one of these options in significant use today is the indirect use of solar energy in the form of hydroelectric generation.

As for the breeder reactor, and true too for today's burner reactor systems, these nuclear (fission) options have characteristic technological uncertainties and developmental lead times. These lead times, which must be gotten through before useful energy can be produced for consumption, are probably of the order of several decades. There is no real assurance of technical and economic success for any of them (and one can include the LMFBR in this consideration). Moreover, unlike solar and geothermal conversion, limited examples of which exist or have been developed in the past, controlled thermonuclear fusion basic feasibility has yet to be demonstrated.

In contrast to the case of geothermal energy extraction as we understand it, solar energy is available for conversion in very large and continuing supply when compared to anticipated future national and world needs.

The rate of energy radiated from the sun is the staggering value of 3.8×10^{26} watts, which corresponds to a continuous loss (conversion to energy) of solar mass of 4.2×10^{12} g/sec, or 4.67 million tons per second! Of this radiant energy the Earth-atmosphere system receives 5.445×10^{24} joules/year, or about 5×10^{21} Btu/year (4).

Noting again the world energy trends of Figure 4, were only 0.1 percent of this incident energy converted to usable energy forms, solar energy could readily support world energy demands of the magnitude forseen in the mid-21st Century.

Furthermore, the basic technical feasibility of solar energy conversion is not questionable: it is already amply demonstrated in at least small-scale. This point was recently made before the Subcommittee on Energy of the Committee on Science and Astronautics, U.S. House of Representatives (5):

"Solar energy is not facing the kind of technological risk that faced Fermi and his co-workers in Chicago prior to first achieving nuclear criticality; they did not know whether their device could be controlled. Neither is solar energy facing the kind of challenges confronting scientists in the field of nuclear fusion. (continued)

"Sixty years ago, a 50-horsepower engine was successfully powered by solar steam along the banks of the Nile River. Thus operation of a solar steam generator does not require any scientific breakthroughs nor solutions to complex scientific and engineering problems. The engineering problems that do exist arise out of concern for economic feasibility and not out of concern for technological feasibility."

Thus solar energy conversion uniquely combines several very desirable characteristics in view of the pressing need to establish a non-fossil energy base:

(1) The basic energy resource is available in abundant quantity,
(2) The technical feasibility of conversion for useful purposes is proven, and
(3) The conversion process is intrinsically clean, providing for a very minimum of environmental degradation.

If this is so, why are we not on a "solar energy standard" today? The answer lies in the economics of the energy industry, and to a related degree, the present lack of technology and system concepts which can be demonstrated to be competitive. Solar energy development has clearly been economically suppressed by the availability of cheap and convenient fossil fuels and low cost energy converters using these fuels. For example, solar roof-top water heaters, very popular in Florida in the 30's (as many as 7 dealers who handle the sales and service for these units can still be found in the Miami Yellow Pages), have been outdated by the subsequent availability of low cost electricity, oil and gaseous fuels.

This trend will be drastically changing in the future, and on a global basis (e.g. Reference 2; Figure 4). At some point in the 21st Century the "low cost fossil fuel competition" will have literally disappeared. This implies the switchover to a non-fossil fuel era for carrying the world energy "load" from this point on or, alternatively, an era of catastrophic change in the very makeup of world civilization.

One way of viewing this energy-base transition which lends a note of welcomed stability and continuity, perhaps, is this: Assuming, as is the tenet of this paper, that solar energy is the ultimate non-fossil energy source we will be converting to, naturally-processed solar energy (the world's fossil fuels) must now be augmented by and eventually supplanted by technologically-processed solar energy.

The present paper, in this view, suggests one such technological processing scheme for consideration.

MATCHING SOLAR ENERGY PRODUCTION AND DEMAND VIA HYDROGEN-ENERGY

For truly large-scale "central" solar energy conversion systems (the only type to be considered in this paper), there are two fundamental problems: First, the location for such solar conversion facilities will be largely dictated by their characteristic large area requirements, and the need for a maximum of solar radiant energy input (clear skies, low latitudes). In all likelihood this will result in their being located at considerable distance from our traditional larger energy utilization or need points: metropolitan areas, high-volume transportation systems, large industries. Second, the timing of solar energy availability for conversion does not usually accord with the time-of-need for that energy by the user. In other words, there is a fundamental problem of energy input/utilization mislocation, in the spatial sense, and mismatch, in the temporal sense.

Acknowledging this problem, Figure 5 calls out the need for an efficient, economic (and practical) means of moving energy -- through time and space, quite literally -- from the solar energy conversion facility to the users in all sectors of utilization: industrial, commercial and residential, electrical generation and transportation.

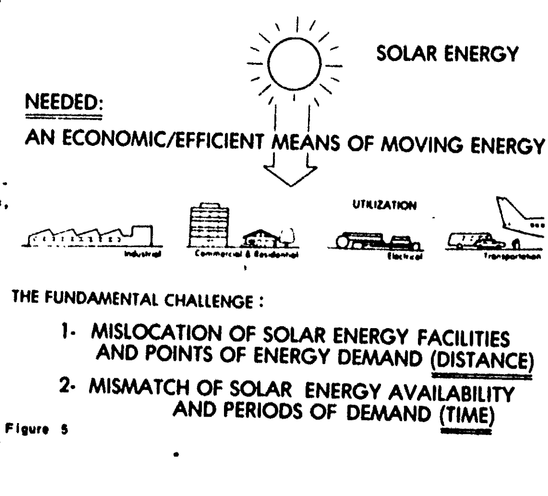


Figure 5

Clearly, what is required is a flexible, practical "energy medium" which is readily and efficiently produced at the solar conversion facilities, and which can be subsequently delivered to distant energy customers. There it can be converted into heat, electricity and shaftpower as appropriate. These conversions should be at high efficiency (to minimise the amount of "energy form" required to be produced, stored and transmitted). Also, at the utilisation end as well as at the central production facility, a benign environmental interaction should be sought.

To date the energy medium to be produced by central solar energy conversion facilities in various studies has been single-mindedly, electricity. Electrical power produced by thermal or photovoltaic converters is fed into utility system grids in such concepts to augment supplies. High-voltage dc transmission, or more advanced cryogenic systems, either cryoresistive or superconducting, have been suggested for long distance transmission.

This means of handling the "mislocation" problem noted above (Figure 5) may be feasible and, thus, a candidate approach. But it will be an expensive one as compared to traditional pipeline energy transmission of oil and natural gas.

Even if advanced electrical transmission technology can solve the "transportability" challenge for a needed energy form, electricity as such is notoriously unamenable to storage. In witness to this, for those conventional means of electrical energy storage (batteries, hydro-storage), electricity is converted to an alternative energy form for storage, e.g. chemical, gravitational. Such a conversion is always accompanied by significant energy loss in the process, which is necessarily a two-way one. Thus the "mismatch" problem (Figure 5) remains a significant issue with the all-electric approach for solar conversion.

From time to time the solar production of hydrogen as a chemical fuel has been suggested as an alternative energy-form to electricity. Hydrogen production possibilities were pointed out in the Solar Energy Panel's recent assessment (1) as well as in a scattering of earlier references associated with the pioneering solar energy technical community (see the official journal of the International Solar Energy Society).

WHY HYDROGEN-ENERGY?

(HYDROGEN FUEL & HYDROGEN-OXYGEN BIREACTANT)

- PLENTIFULLY AVAILABLE
- HIGHEST ENERGY CONVERSION EFFICIENCY
- NON-POLLUTING
- NATURALLY RECYCLABLE

ENERGY ✓ TRANSPORTABILITY
✓ STORABILITY

6

Table 2

Hydrogen as a candidate energy form for solar energy conversion offers a number of compelling advantages as listed in Table 2. For the purposes of this paper the term "hydrogen-energy" means either, and both, hydrogen alone, as a chemical fuel, and the combination of hydrogen and oxygen as a unique bireactant energy-pair.

Though it does not occur usefully in its free state naturally, the potential availability of hydrogen-energy is as abundant as water. In the process of being "consumed" hydrogen-energy returns to water with no net loss of mass.

In almost all energy conversion systems which have been evaluated for amenability to using hydrogen-energy, a maximum of energy conversion efficiency can be reached. Some converters, for example fuel cells, are uniquely oriented toward hydrogen-energy and not only reach maximum energy conversion efficiencies with this energy form but are also greatly simplified and hence most reliable and lowest in cost when designed in accordance with this as their specified input.

Environmentally, hydrogen-energy conversion systems are unexcelled because they produce only water exhaust. An exception to this is the oxides of nitrogen problem for high-temperature airbreathing conversion devices such as gas turbines, reciprocating/rotary engines, and open-flame based heating systems. This single problem can be countered effectively by a number of tactics and the pollutant can be reduced to acceptable levels. Low temperature converters, e.g. fuel cells, catalytic burners, and those devices using oxygen in lieu of air, will produce no nitrogen oxides of significance.

Water exhaust, once freed to the atmosphere from hydrogen-energy conversion systems is naturally recycled by meterological processes and is eventually returned to major bodies of water, notably the oceans in relatively short cycle periods.

Hydrogen-energy, being a chemical fuel (or bireactant pair) used in large-scale industrial quantities already, lends itself quite well to conventional methods and techniques of storage and transmission. Pipelines exist for hydrogen and oxygen, as do gaseous and cryogenic storage containers. For example liquid hydrogen storage tanks approaching 1 million gallons were constructed for the U.S. Space Program.

Thus, hydrogen-energy may well be the most advantageous means of moving energy from the basic transportability and storability standpoints, as basic as these are to the ultimate feasibility and acceptability of large-scale solar energy conversion systems (Figure 5). The electrical utility industry and others in the energy research and development business have given serious attention to the use of hydrogen-energy for electrical energy storage. This serves to demonstrate the relative attractiveness of hydrogen for storage. Based on analogy to the case of natural gas, hydrogen transmission by conventional pipeline systems will be considerably more economic than any electrical means known.

Quite apart from solar energy considerations hydrogen-energy is being given increasing attention in the U.S. and in other corners of the world. Europe is active via Euratom in research and development activity in support of hydrogen, with specific concentration on the use of nuclear reactors for hydrogen production by thermochemical water-splitting processes (6).

The natural gas industry in the United States, in increasingly short supply with its basic methane commodity which clearly must be augmented by supplemental sources (coal gasification, imported LNG, etc.), has begun long-range studies of a possible "Hydrogen-energy Economy" as a means of evolving the gas industry over to a non-fossil basis. However, once again the stress of these studies has been on nuclear energy as the primary source by which hydrogen is produced, either by electrolysis or thermochemically along lines being pursued in Europe (6).

In this pursuit, the American Gas Association is sponsoring a continuing assessment of general and specific aspects of hydrogen-energy at the Institute of Gas Technology in Chicago and elsewhere. IGT has published the findings of its first-year study of the basic feasibility of the hydrogen-energy concept (7), which is a definitive work in this emerging field.

Figure 6 reflects the IGT/A.G.A. concept in its overall approach. Conventional gas-industry means of gaseous fuel transmission in high-pressure pipelines with compressor stations periodically along the lines appears to be technically feasible, though slightly more expensive than with natural gas. It also appears feasible to store hydrogen underground (as most of our natural gas is stored presently) in natural rock structures. The industry, already heavily involved with cryogenic liquids by way of its liquefied natural gas (LNG) activity, forsees handling hydrogen in its cryogenic form also where necessary as a practical proposition, one proven out by the aerospace industry.

Note again, however, as schematized in Figure 6, the gas industry studies have focused on nuclear energy sources only to date. The same is true of the European effort cited (6).

GAS INDUSTRY'S HYDROGEN-ENERGY CONCEPT

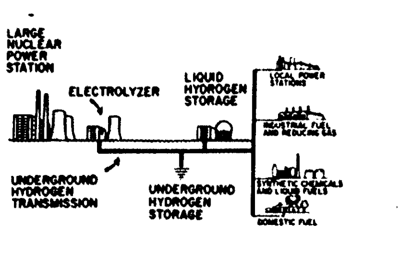


Figure 6 SOURCE INSTITUTE OF GAS TECHNOLOGY

Relative to natural gas (basically methane), hydrogen has a much lower volumetric heating value, about 325 Btu/scf vs. over 1000 Btu/scf for natural gas. For this reason, hydrogen is viewed as a "low heating value fuel" implying considerably more transmission system pipeline sizes, compressor capacities and pumping energy than presently. The same is true for underground storage requirements.

Still the A.G.A. sponsored IGT study assessment concluded the following(8):

> "Although problems exist, no insurmountable obstacles have been identified. An economic analysis shows that the overall concept can be feasible."

Thus, from the point of view of the present paper it would appear that hydrogen-energy produced from solar energy conversion facilities, were it to be made available in the future, will be accepted as a practical energy commodity.

Taking one utilization sector as an example, Transportation -- which uses about 25 percent of the U.S.'s energy budget -- it is instructive to examine its amenability to being converted from its present fossil fuel base (over 98 percent dependency) to hydrogen-energy.

Figure 7 adapted from the Transportation Energy Panel's summary report (9) projects the rapidly mounting energy demand by this sector broken down by transportation modes: ground, water and air.

U. S. TRANSPORTATION ENERGY USE

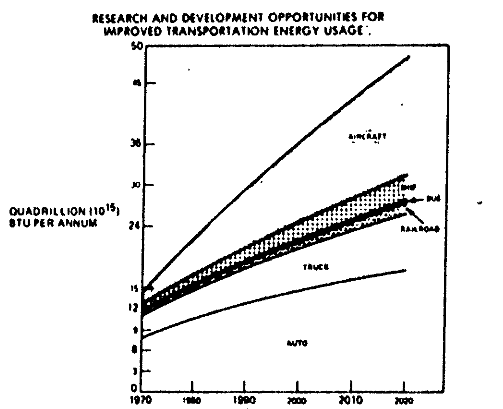


Figure 7 SOURCE REPORT-DOT-TSC-OST-73

It is beyond the scope of this paper to assess in any detail prospects for hydrogen-converting specific transportation systems. This has been accomplished in a supporting report of the Synthetic Fuels Panel (10) in summary manner already.

However, a specific example of a transportation mode which appears to be technically capable of converting from its present petroleum fuel base to hydrogen can be given here. This is selected to be air transportation, from Figure 7, the most rapidly expanding segment of all.

As evidenced in a number of feasibility and conceptual design studies by the aircraft industry and by the National Aeronautics and Space Administration, hydrogen-fueled aircraft are not only technically feasible, they may well prove to be superior designs to equivalent hydrocarbon-based airplanes. This stems from liquid hydrogen (the only practical form for aviation) as a high gravimetric heating value fuel (2.8 times the Btu/lb rating of today's jet fuels). In this vital-to-aircraft parameter, hydrogen is simply unexcelled by any fuel. As a direct result hydrogen-fueled aircraft can be designed to fly farther and carry greater payloads, or to have significantly reduced gross takeoff weights.

To achieve these payoffs the unique technical problems of hydrogen containment in an aircraft will have to be handled: (1) Hydrogen's bulkiness, 3 to 4 times that of jet fuel, and (2) Hydrogen's "deep cryogenic" nature, a volatile liquid at 21 K (36 R, or -423 F). Engineering approaches for surmounting these technical challenges are apparent but will have to be further selected and reduced to practice by appropriate research and development activities.

In view of the Nation's rather critical petroleum situation, an encouraging view of the hydrogen fueling of commercial aircraft is that, by this means, relatively abundant domestic coal resources and eventually nuclear energy can be used to support the continued expansion of aviation independent from petroleum supplies from overseas. For hydrogen can be produced from either of these sources from water. These prospects for the hydrogen conversion of commercial aviation (11) further support the validity of the the paper's basic thesis: ultimate solar-production of hydrogen.

RATIONALE FOR OCEAN BASING

Along with its selection of hydrogen-energy, in lieu of electricity or other fuels, a second departure from traditional concepts for central solar conversion facilities explored to date, the paper suggests open ocean basing of the energy complex.

It is acknowledged that past investigators have suggested the use of sea basing in connection with certain specific solar energy conversion approaches, or conversion modes: (1)Ocean thermal gradient (OTG) systems, and Wind-power conversion, both indirect means of utilizing solar energy in technological converters. Leading proponents for these two system approaches in the United States are the Andersons(12, 13) and Heronemus (14), respectively.

Ocean thermal difference (or OTG) conversion systems operate power cycles between the warm surface waters, which are heated by solar radiation, and the colder water of the depths. They are, therefore uniquely tied to ocean basing to the extent of requiring basic input/output from the ocean as source and sink. Although shore-based facilities can be used, these are apparently not competitive from an entire sea-based energy conversion complex judging from recent work in this field. The cost and parasitic pumping power costs of the long pipelines associated with the shore-based plant is a distinct disadvantage.

The National Science Foundation is presently supporting two separate investigations of the OTG approach, one at the University of Massachusetts under Professor Heronemus, with supporting participation by the Andersons who are consulting engineers (15), and the second at the Carnegie-Mellon University under Professor Zener (16). Zener has recently described the OTG system as a production means for hydrogen as well as electrical energy (17). The University of Massachusetts study is also giving some heed to the hydrogen alternative.(It is worth noting that the earlier wind-power proposals by Heronemus, leader of the Massachusetts effort under the NSF grant, considered hydrogen as a potentially useful intermediary in the production of electricity for the New England area. He especially cited its advantages of storability in matching wind-availability with periods of electrical demand.)

With the OTG and wind-power energy conversion approaches being definite modes for solar energy utilization, these examples demonstrate that the ocean basing concept -- including the emphasis on hydrogen-energy production -- is not entirely a novel approach. Moreover, one of the present authors (Escher) proposed ocean siting for large scale solar thermal conversion systems several years ago(18). This paper underscored the important contribution of the technology of stable ocean platforms as being investigated by the Oceanic Institute and the University of Hawaii. The second author (Hanson) is project manager for elements of this work in Hawaii being carried out under the Office of Sea Grant (additional reference to this work will be provided subsequently).

Ocean basing of such a large enterprise as a central solar energy conversion facility does, on first inspection at least, carry with it several serious liabilities associated with the nautical element. These points will be brought out in the following discussion (see later Table 4).

It is our belief, however, that conventional marine engineering capabilities coupled with the developing technology of large stable ocean platforms (e.g. the Hawaii program) will be capable of effectively mitigating such challenges accompanying sea-based enterprises.

What then are the compelling inducements for ocean basing a solar energy conversion complex? A number of salient advantages will be discussed below, these are listed on Table 3.

WHY OCEAN BASED SOLAR ENERGY CONVERSION?

- VIRTUALLY UNLIMITED AREA
- ENORMOUS THERMAL SINK
- IMMEDIATE SOURCE OF FEEDSTOCK WATER
- EXCELLENT LOGISTICS
- LOW-FRICTION BEARING SURFACE
- AVAILABILITY OF OCEAN THERMAL GRADIENT MODE

Table 3

First off, the intrinsic requirement for very large collection areas for large-scale, central conversion facilities is an all-too-familiar given as a basic proposition of solar energy utilization. Sunlight energy flux on the earth is a relatively diffuse input, vis-à-vis chemical and nuclear reactors, as stated by the basic Solar Constant of 1.353 kW m^2.

The resulting impact on solar energy conversion land needs were graphically presented in the Solar Energy Panel report (1), reproduced here as Figure 8. Attention is drawn to the lower energy scale in this figure."Total U.S. Energy Consumption. For in producing hydrogen-energy in contrast to electricity alone, which serves only about 10 percent of our national energy end-use presently, solar energy can ultimately be broadly applied across all energy using sectors as suggested in earlier Figure 5.

Note that this scale extends to the year 2020, about the time the initial availability of a non-fossil alternative energy system will become absolutely mandatory according to authoritative and recent estimates such as those of Elliott and Turner (2) discussed earlier.

The clear implication in viewing Figure 8 is that very large land areas must be dedicated to solar conversion system usage as time passes if the sun is to be a major non-fossil source of our energy. But much of the U.S. (in the example given here) and any nation generally speaking, is not suitable for solar collector installations and operation for reasons of terrain, climate and other-use commitment. Of the remaining fraction of the land area which otherwise qualifies technically and availability-wise -- typically the U.S.'s Southwest desert area is proposed -- it is not at all clear that this form of land-use will meet with the approval of local citizens, and national and regional naturalist and conservation groups. This issue has yet to be explored on a serious-minded basis.

SOLAR ENERGY CONVERSION LAND NEEDS

SOURCE SOLAR ENERGY AS A NATIONAL RESOURCE
NSF/NASA SOLAR ENERGY PANEL REPORT

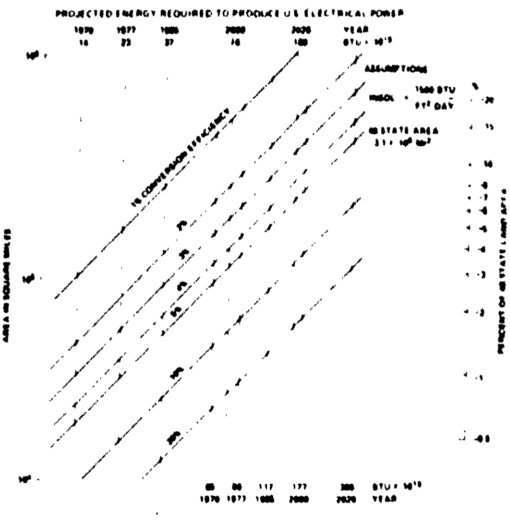


Figure 8

In view of this questionable availability of land area in requisite amounts for solar energy collection in the long run, the vast area potentially available from the sea provides a tremendous inducement to examine the ultimate feasibility of ocean based solar collectors. A cursory glance at a World globe will demonstrate this potential vividly.

Secondly, a conclusive advantage of ocean basing is the ready availability of an almost unlimited source of low-temperature water for cooling purposes. After all, basic solar energy conversion processes are like any others: by nature these are heat-rejecting operations. This heat must be dissipated to as low a temperature sink as feasible in order to maximize the efficiency of the conversion step(s) in order to minimize solar collector size, capital investment, amount of heat to be rejected, etc.

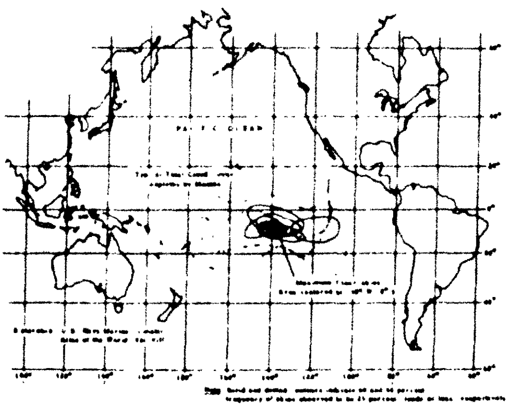
The lack of an adequate thermal sink is proving to be a definite limitation in the case of many of the desert-located solar conversion schemes proposed to date. Often, as a means of cooling, a desalination plant function is introduced into the basic solar conversion complex. In the case of the U.S. Southwest the Colorado river, Salton Sea, or the Gulf of California are named as sources of water in need of purifying.

Functionally, this water is needed for cooling purposes.

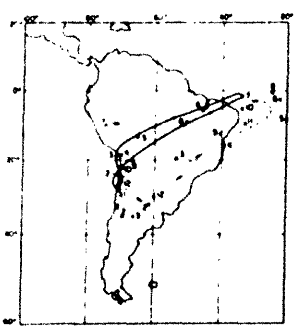
In an ocean based system, thermal rejection to cold depth water, ideal from the thermodynamic cycle efficiency standpoint, can conceivably be very beneficial otherwise. Mariculture, or marine farming is a definite prospective benefactor for which the process of thermal upwelling of nutrient ladened depth waters may be applicable as will be covered later in the paper.

Thirdly, given that the solar facility is to produce hydrogen-energy as its principal output, ocean basing provides for an immediate source of feedstock water. Purification steps will undoubtedly be required to preprocess the seawater prior to delivery to electrolytic cells or equivalent thermochemical reactors. It will be observed that the resulting seawater concentrates may have considerable value in various coproduction schemes which may be considered.

MAXIMIZING INCIDENT SOLAR RADIATION



CLOUD-COVER MINIMUM TRENDS IN MID PACIFIC REGION



SEASONAL DISPLACEMENT OF MONTHLY (NUMBERS) MAXIMA OF SOLAR RADIATION FOR SOUTH AMERICA

Figure 9

A fourth point, all of the world's large-tonnage transportation means are based on water-borne vehicles of one kind or another: viz., tankers, freighters, barges. These are also the most energy-efficient of transport modes (Btu/ton-mile, J/kg-km)(19). Initial construction of the macro system at sea as well as its in-service logistical requirements can be thus met with adequate, efficient logistic means, namely ocean-borne transports.

For instance, global delivery of the hydrogen-energy product as cryogenic hydrogen and oxygen by large Cryotankers', whose forerunners are the LNG cryogenic shipping of today, are envisioned (20). In its construction phase, an ocean based solar energy facility can be supported by worldwide ship-building facilities and logical extensions of these. Such will be far more economic and expeditious than the creation of new land-based facilities in desert regions to serve this need.

A fifth point: in a practical "big-picture" sense the ocean is a very extensive low-friction bearing surface for the translating and rotation of very large areas and masses. Supertankers provide a case-in-point illustration. The ocean based solar energy facility may profit from this fact in a number of ways.

One possibility, suggested in Figure 9's two sketches, is the capability of translating the entire solar collector systems -- at very low speeds of course -- through a scheduled program for the purpose of maximizing incident solar radiation, hence productivity. The top sketch of Figure 9 shows characteristic sunlight maximum" isopleths for a number of months for the Central Pacific region as estimated from marine climatological data. Note the single isopleth (for June) shifted to the right (East) of the hatched locus of maxima otherwise. Perhaps, as a conjecture, allowing the energy complex to move with the solar energy trends would offer an important degree-of-freedom in system optimization.

The fact there are distinctive geographical trends for seasonal displacement of solar radiation maxima is clearly indicated in the lower sketch of the figure. This shows the situation for the South American continent.

As a significant aside, by comparison to land coverage there appears to be a critical lack of ocean area solar radiation data to the extent this has been looked into by the authors. Solar data along with conventional meteorological recordings and sea-state/oceanographic information will be quite basic to the design and location of an ocean based energy complex of the kind being described in this paper.

More local utilization of the "ocean bearing surface" for rotation of large solar collectors for sun-tracking will be illustrated in the later section: "Conceptualizing the Macro System."

Sixth, and lastly, a unique and intrinsic advantage of ocean basing is the availability to the ocean thermal gradient (OTG) energy conversion process, often referred to as "Sea Solar Power." (We are attempting to broaden what is meant by this title in a sense through this paper.) Applicable references for the OTG approach have been given (12, 13, 15, 16 & 17). This approach is basically appealing in its low cost and minimal technology requirements.

However, given ocean basing as a general approach for siting solar energy conversion facilities, what is not yet clear at this time (and to be the object of any system analysis to be mounted) is how dominant a conversion mode should OTG in fact be. Is there an optimal "mix and match" of this mode with others, say wind or direct thermal? Perhaps, for at least certain locales and other circumstances which govern the makeup of the facility, the OTG mode should dominate or be used exclusively.

For the purposes of this problem statement oriented paper, we are considering the issue open, and accordingly list the OTG mode as one of the candidates along with the others.

In any case, the study work being pursued presently by the University of Massachusetts and Carnegie-Mellon will be most helpful in later system optimization in which the role of OTG will become apparent presumably.

Consideration of the "Rationale for Ocean Basing" would be incomplete without noting the "other side of the coin", i.e. the disadvantages. Many of these are obvious of course, issues that have been faced up to by the nautical community over the years. Other marine aspects may pose special problems or constraints in the case of a solar conversion facility which are not so evident (some of these probably will not surface until in-depth engineering studies are underway).

Nevertheless, Table 4 is an attempt to list some of the significant issues as "challenges". A brief comment on each is offered here:

(1) The ocean offers a dynamic, ever-varying interface for a free-floating facility requiring means of flotation, depth control and orientation means.

(2) Because of currents, winds and other disturbances, generally a means of station-keeping will be necessary such as tethering, ocean-floor attachment, or active propulsion.

(3) Salt water and air corrosion is always a major problem to be countered.

(4) Marine organism fouling (e.g. barnacles) may offer severe problems, particularly in heat-exchanger elements.

(5) Inadvertant "overboarding" or accidental dislodgment of equipment may result in an irrevocable loss to the depths.

(6) Question of ocean resources utilization and "ownership" will undoubtedly arise in such a large-scale facility. resolution of these indistinct issues remains open.

CHALLENGES OF THE OCEAN ENVIRONMENT

- DYNAMIC, VARIABLE REQUIRING FLOTATION
- STATION KEEPING REQUIREMENT
- SALT WATER, AIR CORROSIVITY
- MARINE ORGANISM FOULING
- LOSSES TO THE DEPTHS
- QUESTIONS OF "OWNERSHIP"/USE

Table 4

MACRO SYSTEM MAKEUP AND OPERATION

Referring to earlier Figure 3 which depicts the subject macro system as a single "black box", with inputs being the sun and the sea, and outputs being energy (viz., hydrogen-energy) and certain coproducts, the individual system makeup of the macro system will now be gone into. "Macro system" as a concept has been discussed earlier by way of background, see Figure 3.

The basic systems constituting the subject macro system are represented in Figure 10, as is the system interfacing. As noted by the bold arrows in this diagram which track the primary energy-oriented processes, the production of the cryogenic energy commodity is straight-forward. Purified sea water, perhaps augmented by collected rainwater, is electrolyzed into hydrogen and oxygen gas. These gases are stored as appropriate for subsequent liquefaction into the final form and stored for shipment in cryotankers.

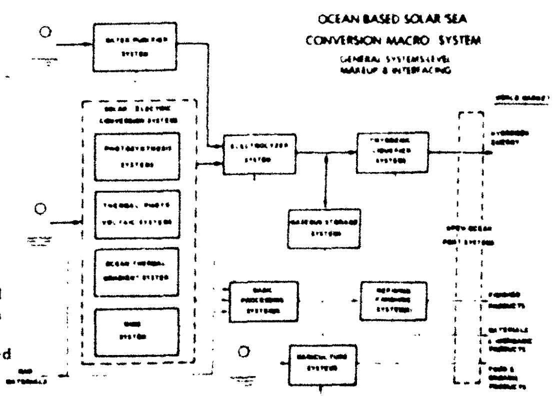


Figure 10

CHARACTERISTICS OF LIQUID FUELS

Fuel (or ref.)	Specific Gravity	Density lb/ft^3	Density lb/gal	Gravimetric Heating Value 1000 Btu/lb (Lower)	Gravimetric Heating Value 1000 Btu/lb (Higher)	Volumetric Heating Value 1000 Btu/gal (Lower)
Water, H_2O	1.00	62.4	8.35	...	...	...
Gasoline	0.72	44.9	5.87	19.1	20.3	112
LNG	0.42	26.2	3.50	21.5	23.9	75.2
LH_2	0.071	4.42	0.59	51.5	61.0	30.4
LO_2	1.14	71.2	9.52	...	.	..
H_2O^* (O_2/H_2, cryogenic, stoichiometric)	0.42	26.2	3.51	5.73	6.79	29.4

Source: Reference 10

Table 5

Table 5 lists pertinent physical and thermochemical characteristics of cryogenic hydrogen and oxygen, along with those of LNG, gasoline and water for reference purposes. Also, the special view of hydrogen and oxygen as a "bulk" bireactant at the unique stoichiometric ratio derived from water-splitting as a method of production (e.g. water electrolysis, as employed here) is expressed here as "H_2O^*". This has been referred to as "the higher energy form of water."

A detailed description of the technical characteristics or a discussion of the state of development of the individual systems called out in Figure 10 is beyond the scope of this paper. Applicable references are available, for example: solar water purifiers, general solar energy literature, e.g. (21), electrolyzers (22,23), cryogenic liquefiers (24,25), open-ocean port systems (26). An earlier study of sizing and integrating all of the above at the 5000 ton/day of cryogenic hydrogen and oxygen production level (equivalent to approximately 1000 MW as chemical energy continuous production) was presented in (18).

Of paramount interest, in view of its being the sole available process for producing hydrogen-energy from water, is electrolysis. Large-scale electrolyzer plants have been operated for many years (23) in locations all over the world, which provides an established base of departure for projecting future macro systems such as that being considered here (Figure 10). The potential for advancements in electrolyzer technology to improve efficiency, already fairly high (65 - 70 percent on a higher heating value of hydrogen output and the net electrical energy input basis), and to achieve a reasonable production cost is quite promising today. Hydrogen-oxygen fuel cell technology, attributable to the Space Program with respect to recent advancements, has much to offer in this area.

Figure 11, extracted from the Synthetic Fuels Panel summary report (27) reflects the estimated build-up and total cost of electrolytic hydrogen, both

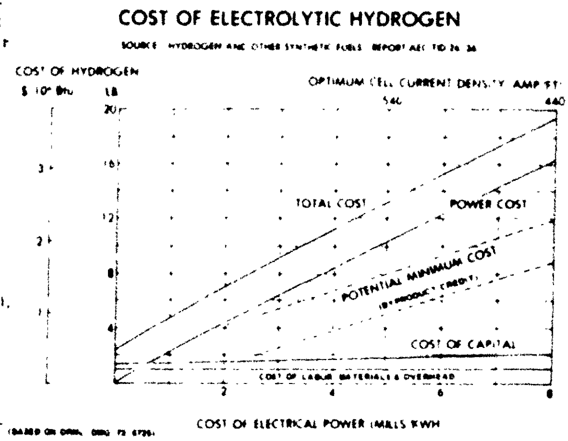


Figure 11

in cents/lb and dollars/million Btu. This projection is predicated on some advancements in industrial electrolyzer technology as mentioned.

Clearly, electrolytic hydrogen-energy production costs are electrical-power-cost-sensitive when conventional power-purchase approaches are considered. As a matter of record, if total energy costs from a projected nuclear-electric generating facility of the type being constructed at this time are realistically assessed, electric power costs well in excess of 10 mills/kWh result. From Figure 11, resulting total cost of hydrogen-energy will be extremely high, and certainly not competitive with today's non-electrolytic means of producing hydrogen (fossil fuel sources). This high cost is a major inducement to seek new energy sources.

As shown by the dashed lines in the figure, a very significant reduction in electrolytic hydrogen production costs may be achievable by the sale of byproduct oxygen and/or deuterium (as heavy water, very likely). The latter is fairly readily producible from the fundamental electrolytic processes involved. Such "coproduction", to be considerably broadened as a basic strategy later in the paper, may be a most significant approach for limiting hydrogen-energy prices in the market-place as produced in an ocean-based solar energy conversion macro system.

Returning to Figure 11, the determination of an "internal" macro system cost of electrical power (electricity is not purchased from a utility, the conventional consideration) must await a detailed systems analysis which is, once again, well beyond the "problem statement" scope of the paper.

Note also that the energy-cost of liquefaction of hydrogen is not included in Figure 11's ordinate values. This will have to be added unless an alternative means of transporting the product from the production site to the using sectors can be effectively introduced.

With reference to the general macro system block diagram (Figure 10), a number of approaches for converting solar energy into electricity for powering the electrolyzer system are shown as contained in the larger dashed "box". Noted here are photosynthesis, direct thermal, photovoltaic, ocean thermal gradient (OTG), and wind systems, as potentially available solar-to-electric conversion modes. Each of these has been individually explored as discussed, for example in the Solar Energy Panel summary report (1). However, seldom are they discussed collectively. Individual system references are: direct thermal (28), photovoltaic (29), OTG (12,13,17) and wind (14).

It may well be the case that a single one of these potential conversion modes would be the logical choice for an ocean based application. Indeed, advocates of the OTG approach attempt to make this synonymous with any "Solar Sea Power Plant." But the systems engineering approach demands that all conceivable solar-to-electric conversion modes be examined for applicability in the initial conceptual phase of such a technological enterprise as under consideration here. Subsequently, as we get beyond the present "problem statement" point and into the detailed systems analysis and macro system synthesis stage, where numbers can be developed, we can intelligently narrow down the candidates we will further consider for solar energy conversion.

Actually, further study may reveal the desirability of establishing a "blending" of two or more conversion modes as opposed to a single one being totally dominant. Whether a heterogeneous (i.e., multimode) or homogeneous (i.e., single mode) approach is optimum is simply not clear at this point. It is for this reason that Figure 10, in effect, merely lists the basic candidate solar conversion modes. It is apparent that each can be made to produce electrical power suitable for powering a water electrolyzer system for the production of hydrogen and oxygen.

SOLAR ENERGY INPUT MODE MATCHING

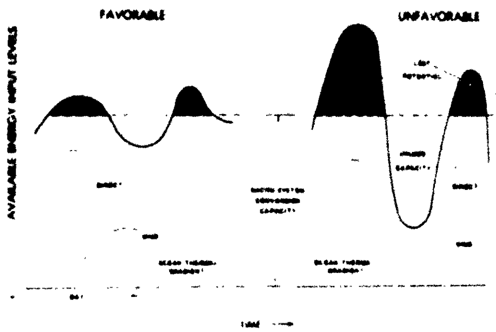


Figure 12

Among the system considerations which must be assessed is the problem of solar energy input mode matching as reflected in Figure 12. The apparent input modes are both of the direct solar radiant energy and indirect (atmospheric and oceanic intermediary) kinds. With reference to the candidate conversion modes represented in Figure 10, photosynthesis, thermal and photovoltaic conversion would involve the direct receipt of solar radiant energy. These are lumped into the single characteristic curves labeled "direct" in Figure 12. The indirect conversion modes of wind and OTG are separately called out. (To the extent that ocean waves are wind-generated, wave energy conversion should probably be added to the list of candidates, wave-pumps as conversion devices have been suggested).

The upper bold line in the two sketches titled "Favorable" and "Unfavorable" in Figure 12 represent the instantaneous additive converted energy available to the entire macro system. Since this will be converted to electrical power (to drive the electrolyzer system), there will be some rated capacity of the macro system to absorb this energy usefully in the production of hydrogen-energy product. This rated capacity is denoted by the horizontal dashed line. Actually, because electrolyzers are rather flexible in terms of operating with both light-load and overload conditions, and because intermediate energy storage possibilities exist (e.g., thermal storage), macro system capacity for energy absorbtion would better be represented by a "band" rather than the discrete line shown, but the latter illustrates the point being made.

Under a "favorable" matching situation (left hand sketch), there is considerable compensation in the direct and indirect solar energy input modes resulting in reasonably good matching of input and capacity. Such is not the case in the "unfavorable" situation (right hand sketch). Here, considerable lost potential (darkened area above dashed line) is experienced. In other words, at certain times, far more solar energy input is available than can be put to work in the facility's various systems.

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Conversely, under an "unfavorable" matching situation, periods of very low energy input will also occur. This implies unused capacity for the facility, or a reduced "plant capacity factor" which means lowered production rates for a given capital investment and operating cost. This is reflected in higher cost of product, an undesirable effect.

Optimization of the solar energy input/facility capacity match will be quite complex since its is a function of many variables including climatological and meteorological factors, as well as conversion systems selection, sizing and interfacing.

Earlier Figure 9 introduces aspects of the general problem with regard to ocean-site location for the macro system. For the direct conversion systems (thermal, photovoltaic, photosynthetic) it will be important to seek a maximum of solar input radiation, a function of season, latitude and clear-skies factors. The upper sketch of Figure 9 attempts to indicate for one oceanic region, the Central Pacific, cloud cover minima trends as developed from available marine climatological data in Reference 18.

World distribution of solar energy received data have been described, e.g. (30), but such seems to be limited in the main to land locations, where the great bulk of weather observation stations have been located. In considering ocean based solar energy conversion, our subject, there is a clear need for oceanic insolation information for basic site considerations and overall input energy assessment.

Illustrating the more adequate availability of solar input information over land masses, the lower sketch of Figure 9 shows the positions of monthly solar radiation maxima for the South American continent. This figure was extracted from (31). One anticipates that similar trends occur over the ocean as suggested by the eastward translation of the single isopleth (for the month of June (18)) as seen in the upper sketch (Figure 9).

One previously noted advantage of ocean basing is the degree-of-freedom opened up by the ocean, surface viewed as a "bearing surface" for translating the entire macro system. Perhaps, to some degree or other, the macro system can be programmed to pursue the region of maximum solar radiation as it moves over the sea in its seasonal trend. This must be left as a speculative possibility at this writing, however.

Returning to the general macro system concept as depicted in Figures 3 and 10, the issue of coproduction of commodities in addition to hydrogen-energy will now be briefly addressed. Listed possibilities are raw materials, finished goods and food. Quite apart from the prospect of opening up an entirely new source of various products in these categories, such coproduction by the macro system may be most effective in increasing the "revenue base" for the ocean based complex, without commensurate increases in facility and operating costs. If so, the basic pricing of hydrogen-energy will be favorably affected thereby improving the competitive position of the overall approach in the energy market.

This general line of reasoning is by no means new; it has been suggested by numerous researchers in the "applied oceanography" field. For example, Anderson suggests (12) that "the sea plant", in this case based on OTG conversion solely, can also produce fresh water, chemicals and sea food. He specifically proposes that such heavy industries as iron ore reduction and steel plants, and aluminum reduction facilities, be colocated on the ocean for advantages of logistics, cheap power and environmentally acceptable waste disposal.

Such possibilities are suggested in the "basic processing" and "refining/finishing" system blocks of Figure 10. As shown, raw materials can either be imported (by ship) or extracted from the sea water concentrates stemming from the basic electrolyzer water feedstock preparation process, or both.

Potable water itself may be an important product for exportation. At the Solar Sea Plant Conference and Workshop held by Carnegie-Mellon University under National Science Foundation support on 27-28 June 1973, Dr. Joseph Barnea of the United Nations Office of Resources and Transportation, noted that fresh water supplies are significantly more in short supply than energy in a large number of the nations of the world (32). In this connection it is well to note that hydrogen-energy, ideally in being converted to useful forms provides pure water as the exhaust product.

A very substantial and instructive study of coproduction of industrial and agro-industrial products from a primary energy based complex was carried out by the Atomic Energy Commission's Oak Ridge National Laboratory in the 1967-68 time-period. The energy source in this instance was land based nuclear reactors. But much of the ground covered under this rather extensive effort, reported on in (33) and a large number of companion and derivitive reports and papers (e.g., 34), is equally applicable to the solar ocean base complex under examination here.

Illustrating this, Figure 13, taken from (34), shows diagrammatically the conversion of sea water concentrates, such as will be derived from electrolyzer feedwater processing in the macro system, to primary, secondary and even tertiary products of commercial value.

COPRODUCTS FROM SEAWATER CONCENTRATES

SOURCE W C LEE INDUSTRIAL COMPLEXES BASED ON NUCLEAR DESALTING WASTE BRINES IAEA SM 126/37

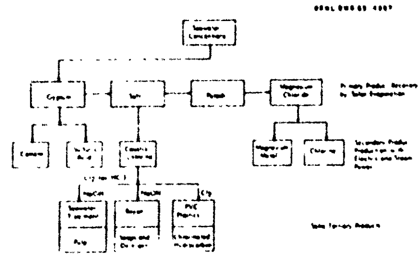


Figure 13

A unique and potentially most significant coproduct area is based on open sea mariculture. A number of advocates of energy conversion at sea have cited the synergistic potential of mariculture and the natural thermal rejection characteristics of energy conversion processes as already touched upon, and to be further noted below (e.g., 12,18,35). In reality, however, very little firm information on open sea mariculture exists. No one, except possibly the Japanese with their near-shore tuna pens and extensive oyster raft arrays, has really attempted to establish mariculture operations on the high seas as yet. Therefore, schemes for associating open sea mariculture with ocean based energy conversion are quite speculative at this point.

Nonetheless, for the past two years the Oceanic Institute in Hawaii, under a Sea Grant from the National Oceanic and Atmospheric Administration, has been pursuing an analysis of the potentials and problems inherent in open sea mariculture activities contemplated for the future. At this writing, an extensive report is being readied by one of the present authors (Hanson) for publication.

Without going into any details of this work, we can say here that a major conclusion of this study is that sessile (fixed to one spot) organisms are the most attractive early candidates. Oysters and mussels in particular have high productivity rates, are contained in the open sea easily and can be raised on plankton. The feed-plankton can be produced in considerable abundance if we can achieve artificial upwelling of waters lying several hundred meters below the surface. These depth waters, too deep for supporting photosynthetic processes directly, are typically rich in inorganic nutrients.

At St. Croix in the Virgin Islands, researchers of Lamont-Doherty Geological Observatory of Columbia University have been carrying on artificial upwelling mariculture experiments for the past several years (see (35)). These experiments are based on pumping deep off-shore water into shallow ponding areas where the subject organisms are cultured. Though of limited scale, they indicate the feasibility of sustaining planktonic populations on artificially upwelled nutrients as feed for oysters and mussels. It remains, of course, to transfer these initial shoreside experiments to the open seas and to expand them to commercially significant scales. Among the more critical questions are those concerned with temperature effects, controlling planktonic species compositions and the mechanics of large scale artificial upwellings.

Regarding the latter, for the macro system application considered here, the mechanism proposed for depth-water upwelling is via thermal rejection in the depths. The colder water of the depths, once sufficiently heated in heat exchange with condensers and other heat-exchange devices which are components of the constituent systems, will achieve positive buoyancy. This will result in the nutrient-rich waters rising toward the surface and into the shallower depths where photosynthetic food-chain processes can be sustained. Thus the controlling process is that of thermal upwelling.

Given that this can be evolved as a practical engineering proposition, another interesting question has to do with the ultimate composition of the marine food web, in addition to the intentionally cultured organisms, that will evolve in artificially upwelled waters in the open seas. Will the dominant "volunteer" species constitute additional productivity, or will they diminish intended productivity? Though many biological and engineering problems remain to be solved, it seems that the potential for associating open seas mariculture with ocean based energy conversion is indeed real and offers challenges matching those of basic energy-form production itself.

STABLE FLOATING PLATFORM DEVELOPMENTS AND TECHNOLOGY

Any ocean based energy system facility will require a stable base of operation. Westinghouse-Tenneco in their joint "Offshore Power Systems" enterprise have selected conventional steel barges protected by breakwaters as the basis for their off-shore nuclear-electric generation facility designs (36). However such an approach is feasible only in shallow water. Deeper water installations for general applicability to the open ocean will require either bottom-mounted platforms or floating platforms capable of motion stability and safe operation in the ocean environment.

The oil industry has led the development of both of the latter two categories. There are several hundred permanent bottom-mounted oil production platforms operating in the Gulf of Mexico and off the California coast. Semisubmersibles (Figure 14) and jack-up rigs are in operation, under construction, or

SEMISUBMERSIBLE OIL DRILLING PLATFORM

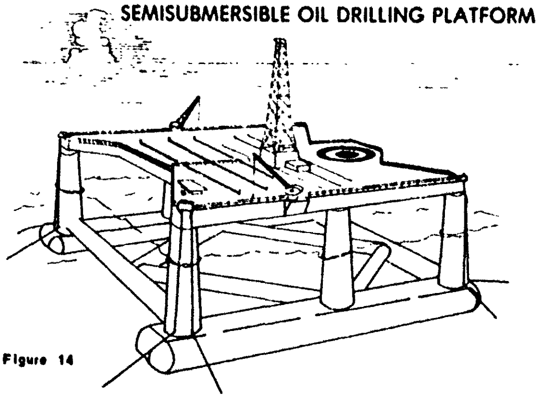


Figure 14

on firm order in quantities of several hundreds of units. The bottom-mounted platforms are usually limited to depths of a few hundred feet. The semisubmersibles are, of course, depth-independent, except for the issue of mooring. We refer here to the platform capability only; all semisubmersible rigs have drilling depth limitations. (37)

As for operations in seaways, the current semisubmersibles tend to cease all operations in waves greater than 30 ft, and begin terminating their more sensitive functions in waves of 15 ft. Most utilize moorings for station-keeping, but many employ thrusters to assist the mooring system in extreme winds and currents. Tolerance limits for platform motions appear to result partly from limitations of crews to perform their functions and partly because of drilling equipment limitations (38,39) In any case it seems very likely that offshore systems of the future will require larger platforms having improved stability over current types of semisubmersible oil rigs.

With this in mind, the National Oceanic and Atmospheric Administration Sea Grant Office has been supporting a joint University of Hawaii/Oceanic Institute research program concerned with very large "super stable" floating platforms under the title of "Hawaii Floating City Development Program"(40). This effort could eventually lead to offshore and open ocean large-scale urban and industrial complexes of the future. It does, of course, take advantage of previous and concurrent related work done by the Naval Undersea Center, Naval Civil Engineering Laboratory and Scripps Institution of Oceanography. One of the authors (Hanson) is actively engaged in the Floating Cities development.

Figure 15 shows two views of a detailed model of one Floating City concept. The approximate dimensions are revealed by noting the basic circular "core" module (best seen in the upper photograph) diameter of 1000 ft. This circular unit is made up of 10 pie-shaped modules, each supported on 3 flotation units as will be later described. The fact that a significant portion of the Floating City is underwater is clearly shown in the lower photograph.

The immediate objective of this effort is to develop critical information on the design and construction of stable floating platforms of very large size and high stability. This very large structure was chosen as an exemplary subject because it could represent the basic "core ring" of a floating urban complex and because its analysis should expose most of the characteristic problems that will be encountered in an actual hardware development program involving, perhaps, smaller or more specialized structures.

To reflect the scale of the Floating City elements, the following design values are noted:

Total deck area (in 4 stories)	199,000 ft^2
Buoyancy chamber diameter	92 ft
" " depth (max.)	240 ft
Upper column diameter	52 ft
" " length	100 ft
Displacement of one chamber (30)	$1.207 \times 10^6 ft^3$
Total displacement of ring	23.1×10^8 lb

HAWAII FLOATING CITY MODEL

VIEW ABOVE THE SURFACE

UNDER-SURFACE VIEW

Figure 15 SOURCE UNIVERSITY OF HAWAII

The work in Hawaii is proceeding along a number of main avenues:

Analysis of the open sea environment employing Gumble's Assumtatic Approximation techniques to develop average and worst expectancies for winds, waves and currents for 100 and 1000 year return periods.

Theoretical investigations and optimization of the platform's seakeeping characteristics (41). This work indicates that heave and pitch excursions can be held to a few feet for the entire ring of 10 modules, even in extreme sea states. The response of the structure is sensitive to longer wave periods. Since very large waves appear to occur in the 15 second period realm and only very small waves of longer periods usually occur in trains long enough to excite the platform, it is indicated that platform motions are very likely to be below the threshold of human perception in all but very unusual seas.

It has been determined that steel-reinforced concrete is the most attractive construction material. An analysis of the use of concrete in sea water has been completed and is being reported.

Transportation to and from such a structure and internal to it poses a number of interesting problems; a report addressing this area is being prepared.

Structural engineering questions are being explored in some depth. Finite element analysis computer programs (NASTRAN and STRUDL) have been developed, as well as several special-purpose programs. This work will be published.

A 1:150 and 1:20 scale model program has been conducted to verify the theoretical work mentioned above. The smaller model (1:150) was an inexpensive unit for wave-tank testing for a preliminary assessment of module behaviour. It was evaluated in Hawaii's J.K. Look Laboratory and in the wave flume of Offshore Technology Corporation in California. Results achieved were in general agreement with theory.

The much more extensive 1:20 scale floating city model is shown in Figure 16. The overall diameter is 50 ft (based on 1000 ft full scale) and the model displaces 150 tons at load water line. The 17.5 ft height of the flotation chambers and their upper columns which support the deck is revealed in the lower on-shore photograph.

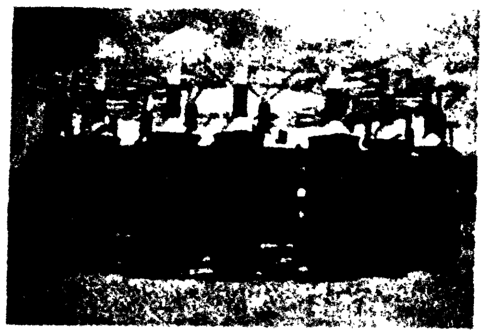
This model was assembled and tested in 1972 in Kaneohe Bay in Hawaii, a natural testing basin for simulating scale open-sea conditions since it features wind generated waves of the proper scale. It was instrumented with sensitive aviation type accelerometers and recording equipment and a large quantity of motion data was acquired in various scale sea states. This will be reported in the Winter of 1973.

An earlier experimental model program conducted by Oceanic Institute under the title, MOSES (for Manned Open Sea Experimentation Station) will be described in the next section.

The major share of the present work as discussed above has been completed and is in the reporting phase. During Fiscal Year 1974 the Institute intends to derive design requirements for a variety of specific uses of this type of platform. As appropriate, this will be followed up by actual design work activity. Included will be floating airports, primary industry sites, waste processing facilities, transportation terminals, resort and research complexes, and pertinent to this paper -- energy conversion offshore and open ocean stations which utilize nuclear and solar energy.

SUBSCALE (1/20) FLOATING CITY MODULE

AFLOAT



ON SHORE

Figure 16

SOURCE: OCEANIC INSTITUTE

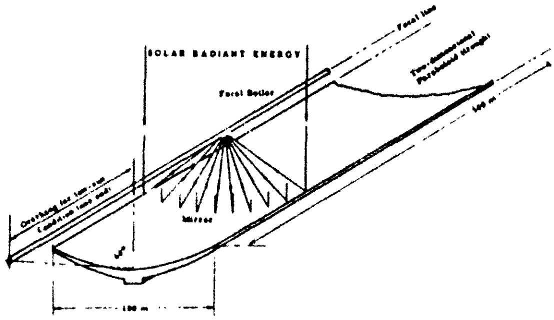
CONCEPTUALIZING THE MACRO SYSTEM

In this final section we will attempt to develop a physical feel for the overall ocean based macro system approach in a necessarily limited conceptualization. First, however it is instructive to examine another aspect of stable floating platform technology, one which we have associated with the important solar collector components of the energy conversion complex.

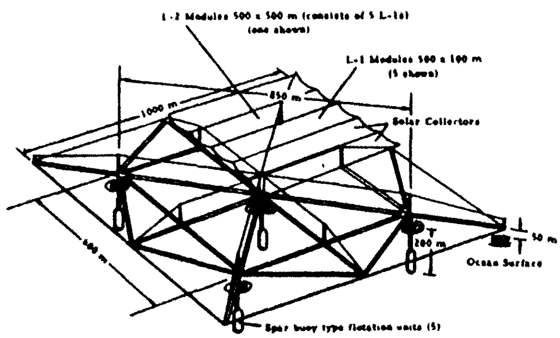
Of course it is the absence of such "technological collectors" which provides much of the basic appeal of the OTG, wind, and some photosynthetic solar conversion modes. These all use natural ocean and atmospheric resources as the energy collection means. But the direct thermal and photovoltaic modes necessitate considering the means of supporting their associated large collection surfaces above the ocean surface.

A special requirement will be placed on stable ocean platform technology in these cases because, in contrast to the Floating Cities application, a much lower "deck-loading" (lb/ft^2) is likely to be imposed by the collection surface.

SOLAR COLLECTOR CONCEPT



BASIC GEOMETRY



1 KM SQUARE MODULE

Figure 17

The upper sketch of Figure 17 illustrates a conventional two-dimensional parabolic "trough" type solar concentrator with its line-focus heat receiver, in which power cycle working fluid is heated. Water as working fluid, and a conventional Rankine steam cycle are considered as a baseline approach in combination with this direct thermal collector.

The strikingly large dimensions noted (100 x 500 m) are strictly arbitrary; a modular approach will be pursued and insufficient study has been made to optimally size such units for the subject application. The module dimensions may be considerably smaller. For example, the University of Minnesota and Honeywell, Inc., working under an NSF grant on central solar-electric generation (land based) concepts have used a nominal 3 x 12 m unit sizing, but one geometrically similar to that of Figure 17. (28)

To illustrate a specific candidate approach for providing large-area solar energy collectors for use on the open ocean, the direct thermal collector concept proposed by one of the authors in an earlier paper (Escher, (18)) will be briefly reviewed. The same general approach would, conceptually, be applicable to photovoltaic collectors except that the sun-tracking feature, to be described, might not be necessary.

Employing some 20 of the collector modules already described, the lower sketch of Figure 17 reflects a basic 1 km square module of collection surface supported on a number of flotation chambers of the type described in the previous section. Since a lightweight structural array is envisioned here, a much wider spacing of flotation units can be employed considerably reducing the total number of supports required per unit area. In other words, a much lower "deck-loading" (lb/ft^2) will be the case here vis-à-vis the Floating City (Figures 15 & 16).

Again, the specific number of units to be applied can not be stated without considerable further design analysis, in which the previously discussed super stable platform technology will be factored in.

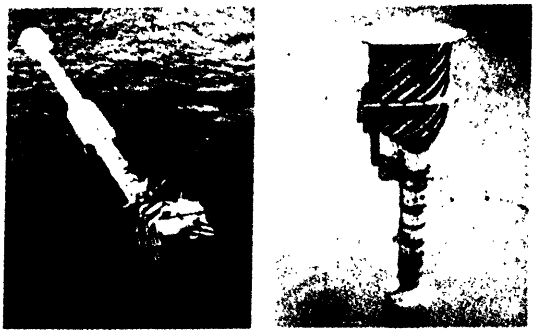
As seen in the Floating City application the basic "spar buoy" flotation unit configuration provides for a stable floating point of support. This is fundamentally because the bulk of the mass and volume of the unit is well below the near-surface of the sea where wave action takes place. The relatively "hostile" air/sea interface is penetrated by a minimal-sized column presenting only a small surface for wave forces to act upon.

This column can then extend upward to sufficient height to support the solar collector well above the immediate ocean-surface environment. As suggested in the sketch, a further extension of the column can be used to support tension members (e.g., suspension cables and various types of riggings) for securing the collector areas. As will be shown subsequently, the top of the columns would be a logical point to attach wind conversion rotating machinery.

Some time prior to the Floating City activity noted in the preceding section of the paper, a well-developed technological base for such spar buoy flotation units was established in connection with advanced-concept oceanographic research vessels, both developed and planned. As part of the NOAA's "Coherent Area Program in Utilization of the Open Sea," in 1970-71, one of the authors (Hanson) managed a feasibility study titled "Manned Open Sea Experimentation Station (MOSES)." A final report for the study was published (42) in which the design of a large special-purpose spar buoy vessel capable of sustained on-station oceanographic research in the open sea was described. MOSES was over 300 ft long and was completely outfitted with electrical, pneumatic, hydraulic and life-support/environmental control systems. A permanent research crew of 4 were provided for.

The report (42) further describes feasibility testing of a 1/13 scale model in the open sea environment. Figure 18 presents photographs of this model in test.

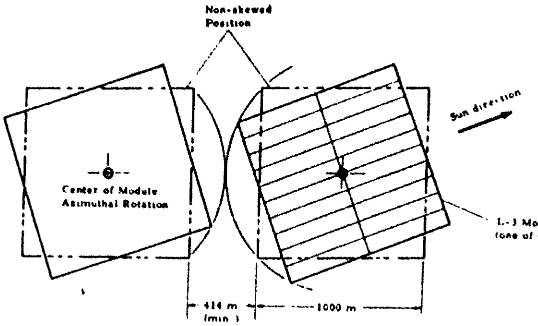
STABLE PLATFORM MODEL IN TEST (MOSES)



FLOATING HORIZONTAL — VERTICAL STABLE CONDITION — SOURCE OCEANIC INSTITUTE

Figure 18

SOLAR COLLECTOR CONCEPT



AZIMUTHAL ROTATION SCHEME

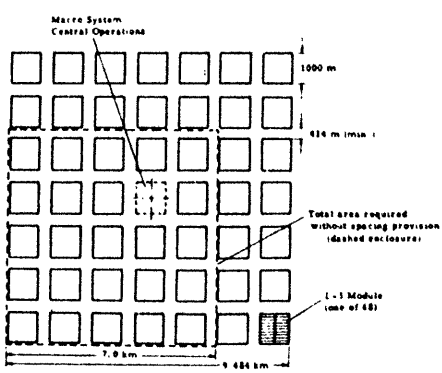


Figure 19 1000 MW (HYDROGEN-ENERGY) LAYOUT

The unit is designed to be towed to the designated ocean research site in the horizontal configuration as shown in the left-hand photograph. Once on station, MOSES is ballasted into the vertical position in which case the bulk of its volume and mass are well below the surface providing the stability behaviour previously described. This vertical "stable" mode is revealed in the right-hand photograph.

In both still and rough water testing in Hawaii, the model evidenced this stability, generally behaving according to the established mathematical model developed for it. Transitions from horizontal towing position to vertical operating position, and return to horizontal -- the dynamics of which were not readily subject to exact calculation -- proved to offer no problem.

Thus, between the present Floating City research and the earlier work on oceanographic research vessels such as MOSES and FLIP, there is considerable evidence in hand that the type of flotation units sketched in Figure 17 is a feasible avenue of approach, on a single-unit basis at least. Much more study of the ramifications of multiple-point support as required for large-scale solar collectors is clearly needed, however, to assess practicability and establish specific features of the design.

With reference to the nominal 1 km square module of Figure 17, the arrangement of a number of these is considered in Figure 19. As shown, there is need for spacing the modules apart to provide non-interference for slow azimuthal rotation of the entire module to effect sun-tracking. This rotation, in the plane of the sea, will be far more straightforward to mechanize than the usual approach of physically rotating the concentrators individually about one axis or another (e.g., about a horizontal axis parallel to or colinear with the focal line (28)).

For concentrator systems, where focusing occurs, as opposed to non-concentrator photovoltaic systems, some provisions for sun tracking must be provided. The rotation about the vertical axis of an upward-facing concentrator as described here is merely one such approach. It utilizes the "low-friction bearing surface" advantage of ocean basing called out in Table 3 to simplify the mechanization of sun-tracking in the very large-scale collection areas being considered here. There is some sacrifice in effectiveness at lower sun altitudes (cosine losses) in selecting this approach over more elaborate mounting geometries; this trade-off stands to be assessed in any further evaluation of the scheme.

The diurnal azimuthal rotation would be so controlled to keep the solar line-image on the working fluid heat receiver. Thrusters in the flotation units would provide the torquing forces for the sun-tracking under the control of suitable guidance systems. Such thrusters would likely be required anyway for basic station keeping and inter-module "formation" establishment. Thrusters of this type are already in use in present-day submersible oil rigs as noted earlier.

The minimum inter-module spacing requirement of 414 m is noted in Figure 19.

TYPICAL SYSTEMS LOCATION

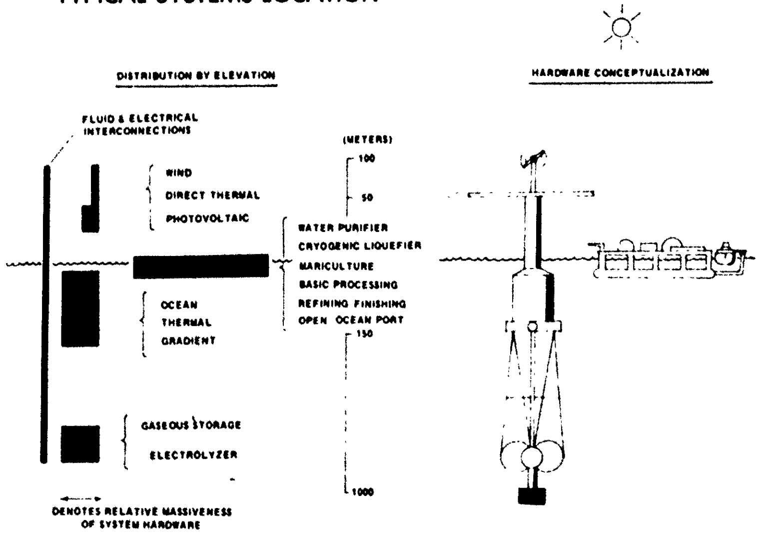


Figure 20

The lower sketch of Figure 19 shows an assemblage of some 48 1 km square modules (7 x 7 matrix; central unit removed for "central operations" activity) estimated as being required for a facility yielding 1000 MW continuous production levels of hydrogen-energy as cryogenic hydrogen and oxygen (18). This corresponds to 609 metric tons of liquid hydrogen and 4890 metric tons of liquid oxygen daily. It was further estimated that a 43 percent reduction in the area required could be achieved with the inclusion of very advanced "projected" technology. Conversely, the continuous production level of the 48 module macro system could be raised to the 1430 MW level.

Finally, we consider the physical integration of the subject macro system as previously schematized in Figures 3 and 10. Figure 20 presents a preliminary conceptualization of the ocean based solar-to-hydrogen energy conversion macro system.

On the left side of the figure an attempt has been made to represent the relative size (mass, and/or volume) of the various constituent systems; this is indicated by the horizontal thickness of the hatched blocked-in areas with system call outs as appropriate. We also show here where the systems would likely be located in elevation with reference to the ocean surface (see nominal elevation scale in center).

For example, it is apparent that the intermediate storage of product hydrogen and oxygen can best be accomplished in depth-located hydrostatically balanced containment units to minimize size and investment, and to provide energy savings in the liquefaction process. This depth storage approach has been considered for the storage of natural gas by the gas industry where underground storage is not possible(43).

The electrolyzer is also shown as depth-located. For if the hydrogen and oxygen are wanted at high pressure, it will be technically advantageous to electrolyze water at that pressure to avoid the considerable energy penalty of mechanical gaseous compression. The compression of hydrogen, particularly is quite energy-intensive, and the equipment costly. Normally, high-pressure electrolysis for which there is considerable precedent in the electrolyzer industry (23), involves basic pressure-vessel construction which is expensive, heavy and poses safety problems. If the electrolyzer were to be located in the depths and electrolysis conducted at ambient depth pressures (about ½ psi per ft of depth as a rule of thumb), these drawbacks might be largely overcome. However, appropriate electrolyzer designs have not been presented; this is seen to be an area of "pacing" technology for the subject concept.

Proceeding upward in viewing Figure 20, the ocean thermal gradient equipment is typically located in the region extending from just below the surface (warm water source) to several hundred feet of depth (cold water source). The OTG system will be volumetrically large, if not massive, due to the large heat exchanger areas involved and the extremely large quantities of water which must be handled (assuming OTG to be a major contributing conversion mode).

Probably the largest number of systems and the greatest mass of the entire complex will be located in the vicinity of the ocean surface. The precept of the Floating City concept is especially applicable in this connection. Such systems would include the ones listed in the center bracket on the figure.

Well above the surface level would be the direct thermal, photovoltaic and/or wind energy collection systems. As previously noted the direct solar collectors may be very expansive areas (see Figures 17 and 19). As previously commented, the uppermost location of the wind converter may make considerable sense for establishing clearance for large-diameter rotating blades and to gain access to maximum wind speeds free from any near-surface blocking effects.

Finally, as depicted on the extreme left side of the figure, fluid system and electrical interconnections of the various systems will be required. This implies piping and electrical cable runs up and down the entire span of elevation, as well as in connecting the various modular units which are to be repeated in a pattern, such as that shown in Figure 19 (lower).

It would seem that the last-discussed constituent systems, that is those associated with solar energy collection direct or indirect, will not be concentrated in "Floating City" fashion, as are the near-surface systems already cited. Instead, the more widely distributed "spar buoy" type of layout would seem more applicable as sketched in Figure 17 (lower).

It may be that the electrolyzer and gas product storage systems would also be "decentralized" and more immediately tied to the energy collectors in addition.

Resisting further engineering speculation, then, the sketch on the right hand side of Figure 20 provides a nominal physical conceptualization of the overall macro system. Note the two distinctive physical units in accordance with the above discussion: (1) Central "industrial" systems based on the Floating City model, and (2) Distributed energy collection modules more in the direction of the spar buoy approach (e.g., MOSES).

In both cases there is an obvious and basic dependency on open ocean or off-shore stable floating platform precepts and technology

CONCLUDING OBSERVATIONS

Having presented this "problem statement" or initial viewing of prospects for ocean based solar-to-hydrogen energy conversion macro systems, it may be helpful to the reader to have reviewed the salient points which become apparent from the foregoing (although not all have been discussed in the body of the paper):

1. World production (and consumption) of fossil fuels is predicted by some authorities to peak out in the period: 2030 - 2080, at which time adequate, reliable and economic non-fossil based energy commodites must be available.

2. Solar energy is the only non-fossil primary energy source (the others are nuclear fission and fusion, and geothermal energy) which is known to be potentially abundant over an indefinite period, and whose conversion technology is fundamentally in hand. It also holds out the possibility of a minimum of environmental degradation, and hopefully none at all.

3. Hydrogen-energy (hydrogen, and hydrogen-oxygen bireactant) appears to be an optimal energy carrier by which solar energy can be transported to the end user of the energy. In this role hydrogen offers key advantages of economic transportability and storability as compared to electricity.

4. Ocean basing of large-scale "central" solar energy conversion facilities, as opposed to conventional desert locations, offers significant advantages of virtually unlimited collection area, abundant cooling water, readily available feedstock water (for producing hydrogen-energy), excellent logistics, amenability for macro system translation and rotation (ocean as a bearing surface), and the unique availability of the ocean thermal gradient conversion mode.

5. On the other hand, ocean basing is accompanied by very significant challenges and limitations. However, traditional nautical architectural and marine engineering methods, augmented by recent developments in the stable ocean platform area, are believed capable of meeting these challenges and ameliorating constraints inherent in this approach.

6. Given the feasibility of large-scale ocean based energy conversion complexes, the coproduction of a spectrum of valuable products ranging from sea foods to minerals and finished goods appears to be a natural adjunct to the basic energy commodity.

7. Among these coproduction possibilities, open sea mariculture is potentially the most significant of all since it may be a major source of augmenting world protein supplies. If the thermal upwelling technique is workable, a rare opportunity for fruitfully using waste heat presents itself and the possibility for achieving a benevolent environmental interaction in a large-scale energy complex is at hand.

(continued)

8. Two basic classes of stable ocean platforms are envisioned for mechanizing the ocean energy facility: (1) Small-area, high density industrial oriented areas employing semisubmersible or "Floating City" design approaches, and (2) Much larger "low deck-loading" areas associated with energy collection processes (among other functions) which may use a multiplicity of widely spaced flotation units.

9. A number of specific candidate solar energy conversion modes have been identified as applicable for hydrogen-energy production: direct thermal, photovoltaic, photosynthetic (including photolysis), wind, waves and ocean thermal gradient. However, a preferred conversion mode for the ocean based macro system, or possibly a "mix" of two or more modes, is not apparent at this point. A complex economic/technological trade-off assessment is indicated for achieving a determination here.

10. Although alternative water-splitting production methods are possible (e.g. thermochemical, photolytic), water electrolysis is the only fully developed and in-use process. Although all candidate solar conversion modes appear capable of generating the requisite electrical power, there are inherent limitations in efficiency in so doing. Therefore, a continued search for superior water-splitting methods should be sustained, while the technology of electricity generation and water electrolysis is further advanced.

11. In the case of the electrolyzer, if depth storage of product hydrogen and oxygen at elevated pressure is shown to be advantageous, the technology of depth-located, hydrostatically balanced high-pressure electrolysis should be vigorously pursued. This will greatly reduce the parasitic energy of otherwise mechanically compressing the gases as well as eliminate the associated equipment cost.

12. If the oxygen component of hydrogen-energy is to be transported with the hydrogen, and since the liquefaction energy requirement is quite high, the opportunity to advance the technology of liquefiers by taking advantage of any synergism deriving from the need to liquefy both gases in a common facility may be quite significant.

13. The open ocean port system, and the noted shipping means for moving cryogenic hydrogen-energy, as well as any coproducts, will involve major developments of themselves. Precedents exist for both, however: projected deep water/offshore receiving ports for supertankers and the cryogenic LNG ships now entering service in considerable numbers.

A final quite general observation is this: Ocean based solar energy provides a unique avenue for any and all nations of the world, even ones at extreme disadvantages in terms of solar energy availability, to participate actively in the perhaps inevitable transition from natural (i.e. fossil fuels) to technologically-processed solar energy.

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LIST OF FIGURES

THE ASSOCIATED GENERAL CONTRACTORS OF AMERICA,
Washington, D.C., November 30, 1973.

Mr. MICHAEL STERN,
Staff Director, Senate Committee on Finance, Dirksen Senate Office Building, Washington D.C.

DEAR MR. STERN: This is in response to your release on Subcommittee hearings concerning fiscal policies in relation to the energy crisis.

Enclosed is a copy of our statement on Federal Energy-related Regulations. This will give you basic information on our Association and our difficulties with the current regulations.

Also enclosed is an AGC News Release (November 27, 1973), which provides information on how seriously our industry is already being affected by the shortages, and by the present allocation procedures.

We are most deeply concerned with your Subcommittee's work, and request an opportunity to testify in person at your earliest convenience.

Taxation is not the way out of this crisis. More taxation, in our view, means more inflation; discriminaton against those who are relatively poor; avoiding the real problem.

It is our belief that the only proper solution lies in an equitable system of allocation or rationing.

The construction industry is being hamstrung by the existing allocation programs. Regardless, however, of our own problems as an industry, we are Americans—willing to live with our share of the shortages and opposed to unfair and counter-productive taxation.

I ask that this statement, and the enclosures be made part of the Subcommittee's proceedings, and that we be given an opportunity to testify in person.

Sincerely,

J. M. SPROUSE,
Executive Director.

Enclosures.

CONSTRUCTION INDUSTRY IN DANGER, WARNS CONTRACTOR PRESIDENT

WASHINGTON, D.C.—The nation's largest industry is in danger of coming to a standstill because of present federal fuel allocation programs, according to a nationwide survey conducted by the Associated General Contractors of America.

"Construction activity in this country is already down 20%," said Nello L. Teer Jr., president of the national association representing 9500 construction firms throughout the country. "If present fuel allocation programs are not altered quickly, the economic impact on the construction industry may reach catastrophic proportions before the end of winter. Our survey indicates that thousands of construction workers are now out of work and the situation is worsening daily," he said.

"The general contractor is not asking for more than his rightful share of fuel," Mr. Teer continued. "He is more than willing to do his share to help alleviate this program; all he is asking for is a better system of fuel allocation to keep his industry going," the highway contractor from Durham, North Carolina added. He said present monthly fuel allocations are made on the basis of fuel consumed during the corresponding month in 1972. He said this type of approach "may be equitable for the majority of fuel users in the nation (whose needs are relatively stable) but has no validity for the construction industry because the fuel requirements on a particular job in a given month in 1972 may be vastly different than the fuel requirements on the same or a new project in the same month of 1973."

He said that weather and the availability of labor and materials could also vastly affect fuel requirements from one month to the next and from one year to the next.

Mr. Teer said he has asked White House Energy Advisor John A. Love to allocate fuel on a project basis so that each job will be assured adequate fuel before it is advertised for bid. "I have also asked that propane for interior heating of buildings under construction be allocated on a priority basis."

Responses to AGC's survey of its chapters representing construction firms, which perform 80 percent of all contract construction, read in part:

"We have had 22 construction jobs shut down this week because of gas, diesel and propane shortage... amounts to $66 million in construction, and a direct layoff of 2200 employees... situation will snowball through the winter months if government stays on '72 base period allocations. I foresee a layoff of 10 to 15 thousand construction workers in Ohio in second quarter of 1974 if present federal program is continued"... *Ohio Contractors Association.*

"Diesel fuel situation critical... $7 million in highway and utilities shut down... 150 employees affected. Additional $10 million in heavy, highway, utilities work operating on day-to-day basis. Construction firms will be unable to continue full production using present allocation procedures... unless there is release. Project 800 to 1,000 construction tradesmen become unemployed." ... *Louisville Chapter.*

"Diesel situation becoming extremely critical in southern California. Increasing number of reports of contractors having to stop entire projects because of lack of fuel ... if situation does not improve, layoffs could approach 3000 to 5000 men before end of year." ... *AGC of California.*

"Effect of fuel shortage in Missouri catastrophic. Without relief, all work will cease. A number of projects already shut down." ... *AGC of Missouri.*

"Fuel shortage getting critical ... engineer dam project was completely stopped for 5–8 days, putting 3000 on-site workers out of a job. Other projects stop-and-go as fuel is available. Black market fuel available on increased price basis." ... *Heavy Constructors Association of the Greater Kansas City Area.*

"Fuel allocation on the base period usage system is not a workable system for the construction industry ... already beginning to show its effects on some projects in this area ... in the near future, will severely cut back most construction operations." ... *Oregon-Columbia Chapter.*

"Unless a more realistic base period is used for diesel fuel and construction is given a priority for use of propane, construction will be reduced by 50% in the metropolitan Detroit area ... employment of building tradesmen would be reduced by 50% ... such a reduction would have a great impact on the overall economy in this area."... *Detroit Chapter.*

"Propane shortage and nonavailability considered severe threat ... winter construction employment levels down 50%." ... *Chicago Builders Chapter.*

"Highway and heavy engineering industry in Arizona will have to completely curtail operations if present base period system of fuel allocation is continued ... extremely unusual weather conditions in 1972 shut down practically all outside work during last months of the year, (therefore) most contractors have very small fuel allocations available ... 12,000 employees are directly involved with additional thousands indirectly involved." ... *Arizona Chapter.*

"Approximately 25% of our 125 contractors experiencing severe diesel fuel shortages ... if situation does not improve, nearly 1,000 men will be out of work within a few weeks with payroll economic impact of nearly $750,000 per month." ... *Kansas Contractors Association.*

"Under present propane and diesel program, 50% of all construction will be stopped by Jan. 1 ... up to 70–80% by March 1 ... stoppages will affect 30,000–50,000 people." ... *Greater Lexington Chapter.*

"Diesel fuel allocations critical ... unless relief or priorities granted, utilities construction statewide will be reduced, minimum of industry employment 10–20% with some contractors forced out of business." ... *Texas Highway, Heavy and Utilities Branch.*

Teer said the energy crisis is the "greatest calamity to hit this nation since 1929."

THE ASSOCIATED GENERAL CONTRACTORS OF AMERICA, INC.,
Washington, D.C., November 19, 1973.

STATEMENT ON FEDERAL ENERGY-RELATED REGULATIONS

The Associated General Contractors of America is a national trade association representing more than 9,500 general construction firms with 122 chapters in all 50 states, Puerto Rico and the District of Columbia. In addition, about 17,500 subcontractors, suppliers and service organizations belong to the association as associate members. Our membership performs the greater part of all heavy, building, highway and utilities construction in the United States, or some $80 billion annually. The construction industry employs approximately 5 million workers, 3.5 to 4 million of which are employed by or through members of our Association.

Construction is the largest industry in this nation accounting for one eighth of our Gross National Product, according to the U.S. Department of Commerce. Not only is construction the largest single piece of our economy, it is the one in which production cut-backs will be most immediately felt throughout the rest of the economy. Construction lay offs follow instantly when work cannot go forward. Unlike agriculture and manufacturing industries, in construction there is no lag between a reduction in volume of work and employee lay offs.

In addition to the obvious public and private reliance on construction for critically needed facilities in the area of housing, communications, transportation, and utilities, there is also a direct correlation between construction and energy output. Refineries need to be built, deep water ports need to be built, mass transit systems and railroads needs to be built and maintained, and sewer plants and transmission lines need to be built. Construction is the vehicle for providing these facilities that will at some future date provide this nation with a better energy posture. "America progresses through construction" is no mere public relations slogan; our nation's economy, employment, and national short and long term planning depend heavily on the construction industry.

It is readily apparent that regulation of energy distribution in our nation is a necessary, long term activity. It is also readily apparent that any regulation must be geared to the public need; to regulate equitably and to do so in a way to minimize the adverse impact on our national economy and employment. In effect, regulation must be balanced against adverse impact. The Mandatory Propane Allocation Program attempts to effectuate this balance primarily through the use of a priority system and secondarily through the use of an historical base period allocation system; while the Mandatory Middle Distillate Fuel Allocation Program attempts to do so solely through the historical base period allocation system.

The effectuation of the balancing approach through the use of an historical base period allocation system appears to rest on a basic assumption that the type, amount, and location of fuel used by an entity during the corresponding month of the base period is a valid indication of the type, amount and location of fuel that will be needed by that entity during the corresponding month of this year.

This assumption is undoubtedly valid for the majority of fuel users in the nation, whose fuel needs are relatively stable and repetitive.

Unfortunately, the historical base period allocation system, and the assumption upon which it rests, is *not valid* for this nation's largest industry—the construction industry. Type, amount and locality of fuel usage in a base period often has no relationship whatsoever to the type, amount and locality of fuel needed at *any other* specified point in time for construction activity. While construction has always been an important fuel consumer, 'base period' and 'normal and average usage' have very limited applicability to construction. This is true for a variety of reasons:

(1) Unlike most other industries, the construction work of individual firms does not 'produce' on a fixed, stable schedule, or even on a forseeable cyclical schedule. The 'raw material' of a contractor is a project, and projects inherently vary in location, duration, type, and quantity— all of which will dramatically affect fuel usage at any given point in time.

(2) Many projects, and the number and type will vary from year to year, are completed in stages, and each stage requires varying fuel usage. For example, in 1972 a contractor may have had a particular project that took five months to complete; but due to the nature of the stages of construction, fuel was only needed in quantity during the first two months of the five month project. This year the contractor may have a very similar project, but in a very different stage of construction, which requires fuel in large quantity during the corresponding third, fourth and fifth month of 1973.

(3) Many construction contractors are highly mobile, moving from one locality or state to another to accomplish projects of varying size and type, under a variety of labor conditions. Each variable affects not only fuel requirements, but also the location and duration of fuel purchasing arrangements with any given supplier.

(4) The construction industry, perhaps more so than any other, is highly affected by weather conditions. Abnormal rainfall stops or seriously curtails some types of construction activity. Preliminary inquiries by our Association

have already ascertained that eleven states last year experienced rainfall in such amounts as to stop or seriously curtail most construction activity for a minimum of 3 months. Yet, contractors in such locations will have their fuel allocation for this year determined by their non-existent or lessened usage of fuel during those rainy months.

(5) Much of the construction industry utilizes union labor. Should a strike or major labor dispute arise there are no inventories to rely on, as in most other industries, to sustain operations until the dispute is settled. A labor dispute in construction activity has an immediate, no-lag effect. For example, Oregon and Southwest Washington state were subjected to a major labor dispute during the months of June, July, and August of this year and construction activities during the heart of the season came to a virtual standstill. If this year's fuel usage is to determine next year's fuel allocation in Oregon, then Oregon is effectively being told to shut down construction all next summer.

The use of a base period to determine fuel allocation for construction activities is completely impractical; there being so many variables that effect fuel usage at any given time. The result is that the regulatory application of a base period allocation system to the construction industry is inequitable and effectively discriminatory. The base period allocation system can only prove to stop or seriously curtail much essential construction activity in the nation; resulting in both an immediate and ripple effect on our nation's economy and employment. In addition the regulatory use of a base period allocation system could have a damaging effect on the competitive low bid process in new federal and state construction; for only the contractor who was fortunate enough, through sheer coincidence, to have a 'good' base period will be able to bid on contracts with assurance of adequate fuel for the project.

An equitable solution, one that would allow needed construction activity to continue and to do so in a healthy competitive atmosphere, is to place construction fuel allocation on a project basis so that each project, whether public or private, will be given assurance of adequate fuel before it is advertised for construction. The awarding agency should have the allocation for adequate fuel to carry on the project prior to the award or advertising of the invitation to bid.

MAPLE SHADE, N.J.

DEAR SIRS: I have read the Newsletter put out by Mike Gravel, Senator from Alaska concerning available means of energy. I am writing in my support for increased allocation for the Research and Development of safe, cleaner, and possible endless supplies of energy such as windpower. I am also enthused about the possibilities of the development of boron-11, which has the possibility to operate with 100,000 times fewer radioactive byproducts than conventional fission plants. It is time we used these safe, clean, and practical means of energy. Man can make his world what he wants—a rose garden or a garbage can.

Sincerely yours,

MICHAEL P. SLANE.

CITIZENS TO PRESERVE THE HUDSON VALLEY,
Catskill, N.Y., December 18, 1973.

Mr. MICHAEL STERN,
Staff Director, Senate Finance Committee,
New Senate Office Building, Washington, D.C.

DEAR SIR: This letter is written for inclusion in this year's hearing record on behalf of the Citizens to Preserve the Hudson Valley, which is a citizens group based in Greene County, N.Y. The background of this organization is as follows: In February, 1973, the Power Authority of the State of New York (PASNY) announced that environmental tests would be conducted at three sites in New York State (two of them in Greene County) for the purpose of finding a suitable location to construct a nuclear or fossile fuel power plant. This particular plant is being planned as a result of the New York State Legislature's actions in 1972, which gave PASNY the responsibility of providing for the future electricity needs of the Metropolitan Transportation Authority.

Our organization formed in opposition to PASNY's probable siting of the plant in rural Greene County. We are calling for a nuclear moratorium, state wide and nation wide, and a much greater concentration of funds and efforts toward developing clean energy, such as solar energy.

Our major accomplishments to date are: keeping the public informed, a dues-paying membership of over 1,000 people, signatures of approximately 5,000 persons opposing a power plant in this area, and the retaining of legal counsel to assist us.

We stand ready to help in any way possible to bring about a widespread use of safe, clean energy sources, rather than those sources that endanger the health and safety of the people.

Yours truly,

MRS. PAULINE DAVIS,
Chairman, Legal and Political Action.

Carolina, R.I., December 14, 1973.

DEAR MR. STERN: I wish to have my opinion expressed to the Senate Finance Committee. It is as follows:

After billions of tax dollars and all the years of my life, nuclear fission has provided no more than 2% of the nations energy. Coupled with its highly radioactive waste products and incredible waste disposal problem, I should think that the men that dole out the money would take a good second look.

There is clean inexhaustible solar energy to be developed. There is wind and water power to be utilized. There is the possibility of cleaner nuclear reactions using proton-Boron 11. Why isn't the bulk of money going in these directions.

They say a house is usually torn down before it falls down. I personally am sick of letting things stand that were poor investments to begin with. And with a record of little return for the dollar spent, I ask for reconsideration of where our tax dollar is going. Nuclear fission (uranium and plutonium) is to my way of thinking, one of the worst investments we've made.

The next part of my letter will ask questions about the oil shortage and its relationship to money spent.

Is the oil industry held accountable for any tax and federal subsidies it receives?

How much money does the oil industry receive to subsidize drilling and oil discovery methods?

Has the oil industry shown any return on the money spent?

How much domestic crude oil is processed and consumed by this nation—how much is exported?

How much money is spent subsidizing the development of technology of safety devices to prevent spills?

Thank you.

ROBERTA H. ANDERSON.

TILLAMOOK, OREG., *December 13, 1973.*

To: MIKE GRAVEL,
U.S. Senator, Alaska:

Subject: Your Newsletter of November 30, 1973.

Thanks for the invitation to express some views on the National Resources Defense Council—The Atomic Energy Commission—The National Environment Policy Act and The National Science Foundation.

The longer the United State Government continues with the mechanics of obsolescence, politics, finances and ecclesiastical interference, the quicker it will go down the drain and the people with it. There's never been a time in history, especially over the last forty years, that this country has been in worse shape. It is manipulated by decadent leadership: Has gotten itself embroiled in one messy international affair after another: Has all but exhausted its most vital resources through deliberate waste and inefficiency: Has become financially bankrupted, choked with over two trillion dollars of Price System Debt.

The credit for these achievements must be placed on the door steps of those mechanics of the Price System.

The years have rolled by what was once a future consideration is now a Present problem, especially loading the Ocean with radio active waste that will tell its story all too soon. Tomorrow has become today, and we are approaching the deadline for action. Do we have what it takes to put up a scrap for this civilization? Or have we turned out to be a bunch of slobs not worthy of survival? An individual with self respect wouldn't have any trouble making a decision. Technocracy's "Design" is the only answer or solution to our Problems.

It is hoped that the personnel of the NRDC—the AEC—the NEPA—the NST and U.S. Operating Engineering Cooperate to the fullest efficiency to promote Windpower, Solar Power, Thermal Power as well as other kinds of power using replaceable resources instead of Non-replaceable.

Enclosed are some Briefs on Technocracy's "Design" of social operation that you may enjoy.*

Sincerely and Happy Landings,

OZZIE S. FORD.

EDWARD F. WEHLAGE AND ASSOCIATED ENGINEERS,
Whittier, Calif., December 13, 1973.

Re Energy Trust Fund Hearings—1 Geothermal Energy as a Nuclear Alternative.

Mr. MICHAEL STERN,
Staff Director, Senate Finance Committee, Senate Office Building, Washington, D.C.

DEAR SIR: The following material is submitted on the assumption it may have some interest to the Subcommittee on Energy in assessing the potential value of geothermal energy. (Per Senator Gravel's November 30, Newsletter).

1. From—Geothermal Energy Magazine—October 1973 Article "Conference of Plant Engineers—Geothermal Paper.
2. From—Consulting Engineer Magazine—August 1973 Article "Tests Run on New Prime Mover for Geothermal Power Generation."
3. Interview with Roger S. Sprankle on electric power production with the Helical Screw Expander.

Sincerely yours,

EDWARD F. WEHLAGE, *Professional Engineer.*

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*The briefs referred to were made a part of the official files of the committee.

GEOTHERMAL ENERGY MAGAZINE

CONFERENCE OF PLANT ENGINEERS

GEOTHERMAL PAPER

JUNE 14, 1973
Los Angeles

EDWARD F. WEHLAGE, P.E.

INTRODUCTION

The Astronauts have pretty well demonstrated that heaven is a little farther out there over our heads than we thought it was. Now, the geothermal boosters appear to be bent on proving that HELL is a lot closer down there under our feet than we expected. It does seem pretty hot down there.... Which is what most of us expected — anyway! ! !

While trying to look in on the future of plant engineers using geothermal and hydrothermal energy, I must be more of an observer than a geothermal expert. All crystal balls get cloudy once in a while, so I am sure that some of my friends who are real geothermal experts may take strong exception to some of the things I see ahead.

My own enthusiasm for geothermal energy has to be tempered by my judgement of what I might find in practical plant operating experience. In general, I see a wonderful opportunity ahead to save great quantities of fossil fuels . . . . but an opportunity marked with some problems that will range from mechanical and chemical . . . . to money and human beings.

So why don't we take a look at my crystal ball for a while and try to see what might be ahead for plant engineers as they begin to use geothermal and hydrothermal energy?????

PLANT ENGINEER'S RESPONSIBILITY

At the turn of this century, the plant engineer may have worshipped on Sunday with his head in the cylinder of a recalcitrant steam engine, but he was usually the local power expert. Today, his counterpart has assumed the role of a broadly experienced engineering manager for industrial housing and production facilities - still retaining the same primary interest in fuel, power and energy.

Around 1900, just about every establishment - industrial, hotel, office building, hospital, college campus, or brewery - bought fuel and its own producer of power and heat. As an engineer "The Old Timer" was facing change, just as every plant engineer today is confronted with crises. The age of the public utility as a central source was yet to come, but labor and management problems, economics, and technical growth were already working toward a major change in power plant (and energy) practices.

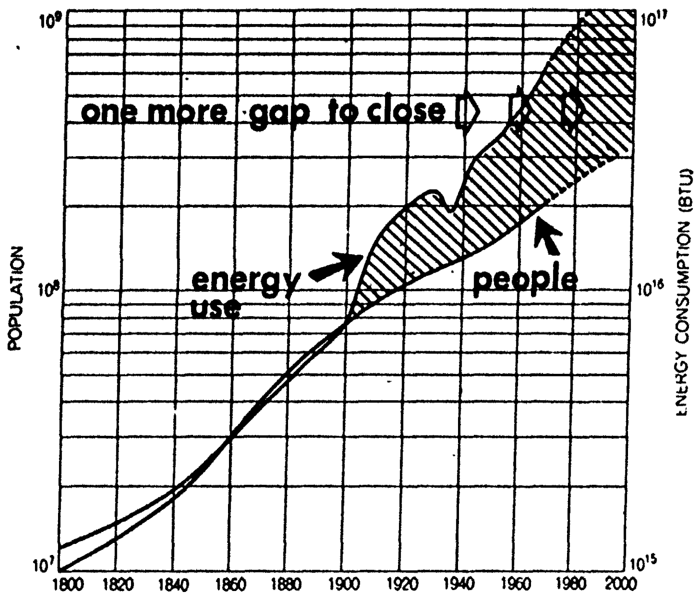
In 1973 new circumstances are creating challenges for industry power practices. Plant engineers are going to be intimately concerned because their departments will be the users of any new technology, and iron out the "bugs". The need for changes in the industrial power field, for heat conservation, for power reduction, for better buildings, for lower heating and cooling costs, is both imminent and real, and must affect industry and utility practices..... perhaps calling for some form of on-site power.

CRISIS NOW — REALLY IN CHEAP POWER

While it may be near, if there is a crisis today it is more in the realization that the end of an era is at hand. In the United States today, no one can say he has been seriously harmed by any fuel and power hardship. So far the hurt is that more people are becoming aware that something uncertain, and probably painful, appears ahead. The crisis is not with energy of any kind . . . . the true immediate crisis is the approaching end of an age of **Cheap Power and Energy** in the U.S.A. and the world at large.

The real crunch lies somewhere in the twenty five years ahead. We must live and work against that uncertain day and narrow the serious gap between or rising "power use" curve and "population growth" curve. A quarter of a century passes quickly. I recall being taught at school during the 1920's that there would be little coal and no petroleum available by 1940. We all realize that the day of doom did not arrive as predicted but now our forecasters are better equipped to look ahead now than they were 50 years ago.

The sources of liquified natural gas in foreign countries and the relaxation of import quotas on oil can relieve pressure on our domestic needs for several decades . . . . if we can stand the money strain. The plain fact is that our American industrial system is not producing . . . . some of our



U.S. ENERGY-CONSUMPTION GROWTH *(curve in color)* has outpaced the growth in population *(black)* since 1900, except during the energy cutback of the depression years.

"......INDEFINITE GROWTH IN ENERGY CONSUMPTION, AS IN HUMAN POPULATION, IS SIMPLY NOT POSSIBLE."

EARL COOK IN SCIENTIFIC AMERICAN

products are not saleable abroad and our salesmen are not selling for a counterbalancing export economy. In other words, we are losing out. I was in Europe last January (before devaluation) and the U.S. dollar was not what it ought to be. Payments for imported oil will place large amounts of U.S. funds in the hands of foreign (and perhaps unfriendly) oil interests. Already there are proposals for exchanging U.S. obligations for control of our domestic corporations. Plant engineers may awake one morning to find they have a new breed of boss installed by foreign oil potentates.

SUBSTITUTIONS?

One forecast for the year 2000 predicts U.S. industry will use 55% of the electric power produced from all sources - nearly doubling 1970 requirements. Can we afford this if costs increase as promised ? No plant engineer working today will survive to again see low and competitive prices for fuel and electricity. If circumstances combine in the worst way, what can we do about it ?

We know the plant engineer is going to be forced to upgrade performance, institute rigid conservation measures, use waste heat and look for new sources that are applicable to his operations. Social pressures, and the pressure of costs will require whole new methods in industry, even to getting a new location for plant operations. The demand for new sources of heat and power, in the face of rising prices, will force consideration of things like nuclear packages, solar heat and, particularly in the Western U.S.A., **Geothermal and Hydrothermal energy.**

THE EARTH'S HEAT

Geothermal is precisely what the derivation indicates - using the earth as a source of heat. There can be no question but that the potential is vast and real, but when utilization is considered we stand at a threshold comparable to the use of the steam engine at the time of Watts and Newcomen... perhaps a marvelous discovery, but how can we use it and will we find problems ?

The laws of physics which govern engineering and thermodynamics have not been repealed. The challenge is to learn where the factors of friction loss and heat dissipation impose a sudden halt. Plant Engineers are going to help determine this by hard practical experience as they find it necessary to move into this field and utilize it for industrial heat and power. The **true future** of geothermal and hydrothermal heat rests in relatively low temperature applications and that future will only be realized when these sources are developed and proven so Plant Engineers can literally buy them "off the shelf" and put them to work.

AN INDUSTRY — UNREADY

Now we must nurture an entirely new industry- **Geothermal** - which today has no effectively developed technology for utilization. Except for a certain few ideal electric power generation areas, there is no widespread experience on which to base the actual use of geothermal. There is a long road of learning and hardship ahead for geothermal application in the U.S.A.

For years, the entire geothermal establishment in the U.S. has worked hard at exploring a geological curiosity by drilling prospective wells, buying and selling leases or property, fighting tax procedures, and learning what may be in the ground, but with virtually no thought or research devoted to anticipating the use of the heat if it suddenly became abundant. The trend of thought has been directed toward a vague hope that the electric power producers would be miraculously forced to develop the utilization facilities.

The learned institutions, the "think tanks", the utility companies, and our government agencies have delved deeply and the results are in voluminous paper reports. As far as I can determine, there is very little money currently allotted for down to earth working study of equipment except the Imperial Valley desalination project funded by the Bureau of Reclamation, U.S. Department of the Interior, and the Magmamax tests at the Salton Sea. In a few instances, limited private money is being spent.

We now face a difficult opportunity without adequate practical experience and without funds to cope with the problems thrust upon those who would like to deliver results in today's geothermal world. There is a seriously felt need for real practical working information now - when we are already at least ten years behind.

It is a popular misconception that geothermal will be the solution to all future heat problems. The implication has been that any hole drilled deep enough into the earth will be connected to a power generation station to deliver unlimited electrical energy for all time to come. For those people who believe that "**science with enough money can solve every problem**" in the geothermal field, I can only suggest a visit to some of the present day hot water wells to learn of the serious corrosion and mineral deposition problems - the kind which are so familiar to plant engineers everywhere.

SERIOUS DIFFICULTY AHEAD

The greatest single danger is that uncontrolled enthusiasm and impractical efforts - without adequate time for work and practice - could turn realization of the true merit of geothermal energy into a great boondoggle and set back its real progress for another twenty five or fifty years.

We have a national tendency toward an "out of sight - out of mind" philosophy. Not until a nation-wide problem gets too big to hide do we encourage doing anything constructive. By then the problem is usually too big and complex to solve reasonably. An awful lot of people just are not getting the message that we should be walking briskly toward a goal - neither sitting and talking - nor running wildly.

SUCCESS AT HAND

A few fortunately situated areas of the world have achieved remarkable success with the production of electrical power from geothermal steam. The world's crown jewel of geothermal fields for electric power production is a rare dry steam source at The Geysers here in California, with the guidance of Pacific Gas and Electric Company, it will have nearly 400,000 kilowatts capacity at the end of 1973, and 106,000 more in 1974 and again in 1975. This is the only completely private investor geothermal utility operating in the world. Government sponsored operations in Italy, Iceland, New Zealand, and Mexico (the newest) are impressive - and practical. I am not really certain just who really owns the plants in Japan. Each installation has its own special merit - with a corresponding set of problems - and a common denominator, they work... as long as there is a matching steam turbine cycle.

HOT WATER AS A RESOURCE

All around the world hundreds of exploratory and producing wells are being put down with the idea of building central electric power generation facilities and extending those already in successful operation. Not all of these bores will be suitable for large scale electric generation and these are the locations which are most likely to become available for industry requiring rather large quantities of low temperature heat - say under 350° F. The best high temperature sources, will of necessity, be given over for utility power generation. There are already many good hot water wells and more will come.

Hydrothermal Energy is available as heat and pressure stored in earthbound hot water. Under sufficient natural heat it will be usable in many plants requiring heat for processing. It will be widely available for pumping at temperatures below 350° F. In the depths of the earth this water may become a brine stored at temperatures of 600 to 800° F. but in nature it seldom reaches the surface above the boiling point. At this time there is a great need for bore hole pumps which can lift the very hot water some 3000 feet out of a ground reservoir and deliver it for use. There appears to be no practical pump design in existence at the present time - another plant engineering problem.

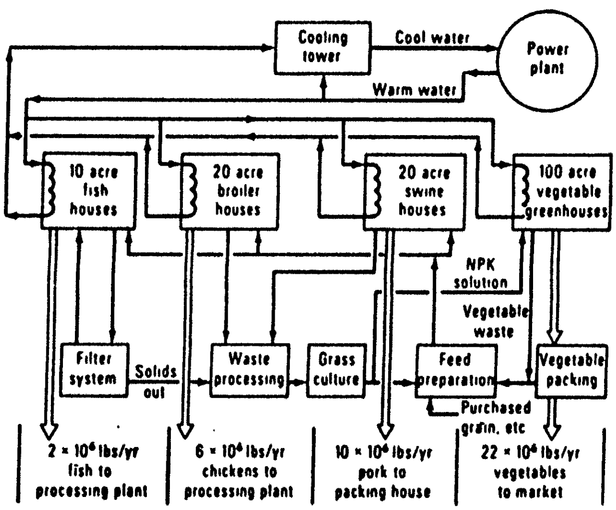
If fuel oil were to sell at $ 0.75/gallon, or more, then there would be some real commercial and industrial interest in searching out, in leasing, and in buying hydrothermal heat sources. Industries and whole communities will then probably be sited where this heat is available if oil, gas and coal get more scarce in the next 25 years - and certainly sooner if the supplies fail. Geothermal heat is already competing on an even basis with other fuels as fuel prices rise and its use must increase with the passage of time.

OLD & NEW USES

Traditionally, the outlet for this hydrothermal energy has been in spas for comfort and therapeutic purposes with a history of several thousand years. More recently, hot water from thermal sources has been put to use for heating in areas where conventional fuels are harder to buy. In Northern California, Idaho and Oregon many homes are already heated with hot water from wells. The Mormon Church at Susanville has been heated with hot water for many years. Recently, Lassen County advertised for bids to heat a shop with hot water to be taken from a well. In Nevada, explosives are melted with hot water since it is both safe and available. Warm (and often cold) water wells provide a heat source for heat pump applications. There are other uses, too, and these practical ideas offer a sign post for the future.

Iceland makes excellent use of hot water which is delivered and metered on a utility basis at 80°C, for the capital city of Reykjavik. In Iceland's far north, geothermal steam is separated from hot water and used to generate some electricity and to dry diatomaceous earth in a commercial plant operation managed by Johns-Manville de France and Kisildjan H.F. (The Icelandic Diatomite Company, Ltd.) . Farm houses, homes, hotels, hospitals, small industries and commercial buildings utilize this hydrothermal energy in a manner that is most socially advantageous by reducing fossil fuel imports. No one else manages it so well today.

In the use of this hot water and high enthalpy brine, heat exchange equipment will usually present all of the problems now familiar to plant engineers. Corrosion resistant materials and special plastic coatings will be required to keep

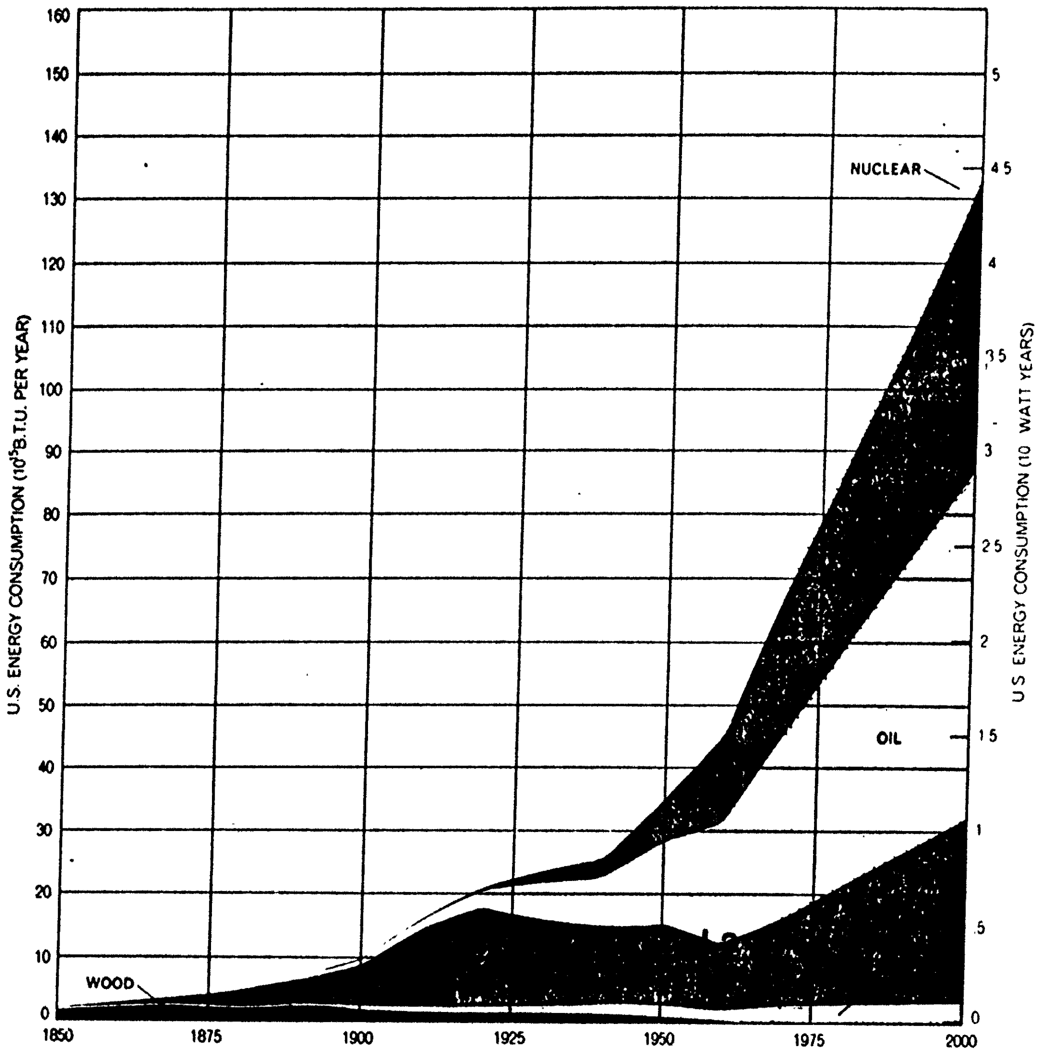


"BLUE SKY"?? now –– or–later on ???

SUBSTITUTE A GEOTHERMAL AND HYDROTHERMAL STATION TO PROVIDE CIRCULATING COOLING AND HEATING WATER

ADAPTED FROM "NEW SOURCES AND METHODS - TOTAL ENERGY - A KEY TO CONSERVATION", SAM E. BEALL, JR., OAK RIDGE NATIONAL LABORATORY......CONSULTING ENGINEER, MARCH 1973

GEOTHERMAL ENERGY - OCTOBER, 1973



U.S.A. ENERGY USE HISTORY

equipment in service. The deposition of mineral substances when the hot brines are cooled presents a severe hazard.

As the hot water circulates in the depth of the earth at high temperature, it picks up about every mineral known to man - calcium, silica, iron, magnesium, boron, and mercury. Some obnoxious sulfur compounds abound - Mother Nature must love sulfur, she has so much of it.

While certain types of hardness may precipitate out on temperature rise in ordinary water heating, the solubility of silica rises with the temperature and may give disastrous scale formations for geothermal equipment - just as it does in boiler service. An entirely new water treatment technology must surely evolve with any increased use of hydrothermal energy.

TRANSPORTABLE POWER

Fossil Fuels possess the unique quality of being both transportable and capable of being stored for use. Electric Energy is highly refined power and is extremely well adapted for transportation. Raw geothermal and hydrothermal heat is not transportable over any appreciable distance and must be utilized almost "in-situ". The net result is, that to make it transportable, it must be converted at low efficiency by electric power generation (where possible), or better yet, utilize every B.T.U. for direct process in an industrial plant complex located near the source, and then transporting a product.

It can be forseen in a geothermal age that any industrial installation may be required to have some "on site" power generation capability to meet electric demands. For an industrial project to become self sustaining in energy, there may be a reversion to the days when some "water power" was a sine qua non for a manufacturing site. A capability to produce - or find - domestic and process water will also be tied into site requirements.

EQUIPMENT IN EARLY STAGES

A promising geothermal prime mover is currently being developed and tested by Hydrothermal Power Company, Inc. using private funds and under the guidance of Roger S. Sprankle. Described as a "Helical Screw Expander", the machine utilizes hot, pressurized, geothermal fluid as an energy source in a reverse cycle of the rather new screw compressor invented in Sweden for air and gas. The expansion of the steam released within the machine and the available fluid pressure combine to deliver rotary power with a steam/water mixture direct from a well. I witnessed the start-up of a test at the Cerro Prieto field in Mexico and it can successfully produce power from hot and corrosive well effluent, quietly and apparently without excessive wear. Utilization of the exhaust in process work could make it quite adaptable for industrial use. The U.S.A. geothermal production industry has not expressed any serious interest to date in developing use of this machine.. A "geothermal water wheel".

A community requiring central cooling and heating from a hydrothermal field for the comfort of people, or for an industrial plant, can be served with a central circulating supply system. Many of the potential working sites will be in areas where heating and cooling is needed for comfort. These requirements can be easily met without demands on fossil fuel supplies where geothermal or hydrothermal energy is at hand, especially if a device like the Helical Expander develops as promised.

In our office we have already produced designs for water chilling and heating modules that have stood the test of several years of operation in the desert areas of Arizona. We have designed these to work as modular packages. At this time we have completed the design for such a modular installation in multiples of 100 tons refrigerating capacity with special helix coil heat exchanger equipment to use a geothermal or hydrothermal source of heat.

These packages can be modified and multiplexed for installations ranging up to 1000 tons per group. A simple earth insulated distribution system can serve a community of substantial size to deliver heating and cooling, just as the city of Reykjavik, Iceland, serves domestic hot and cold water to its homes and buildings.

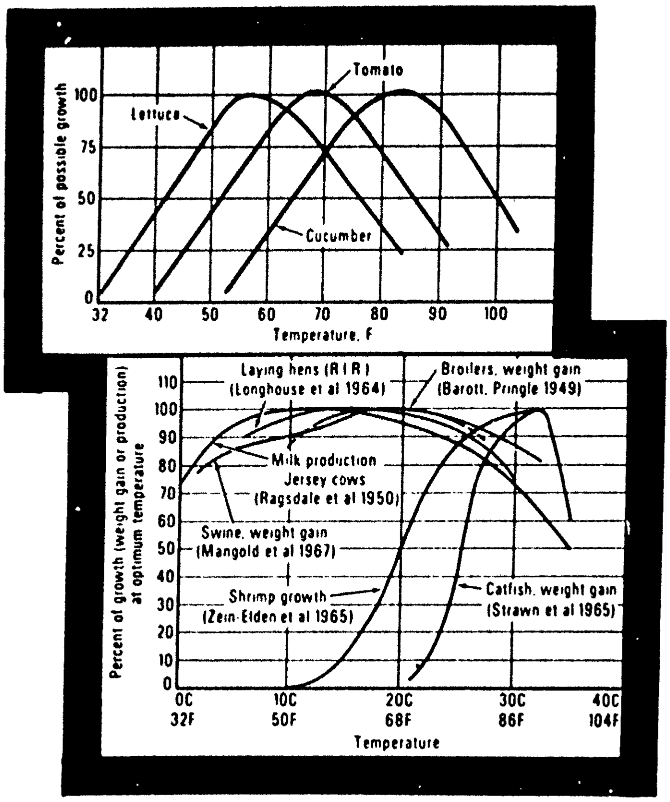
RUSSIA EXPERIMENTS

In the field of small geothermal electric generation units, the USSR offers evidence of achievement at a location in Russia called Pauzhetka.

The steam/hot water wells are about 1000 feet deep. Steam is separated from the water and delivered to the turbines at 1 to 2 atmospheres - say 20 psig. The plant is rated at 5 Mw and generates 35,000,000 kwh annually for a collective fishing village 20 miles away. At a cost of 7.2 mils./kwh, it is 30% below alternative power costs.

The low steam pressure at the turbines indicates what might be expected at relatively good geothermal wells. This is not disconcerting when one considers that several excellent industrial applications in the U. S. A. have utilized four pound steam in turbines. The steam rate may be high per unit of output, but the replacement of of a very important quantity of fossil fuel can become extremely valuable.

Total Energy Can Be ——



"AGRO — GEOTHERMAL PRODUCTION"

Facilities.....

ADAPTED FROM "NEW SOURCES AND METHODS - TOTAL ENERGY - A KEY TO CONSERVATION", SAM E. BEALL, JR., OAK RIDGE NATIONAL LABORATORY......CONSULTING ENGINEER, MARCH 1973

U. S. A. TRIAL

Most of the promising generation schemes at present offer relatively small capacity units when compared with the major utility central stations and this may call for some change in thinking. The utility companies are basically large scale power manufacturers with retail level distribution-not retail level production. One ~~of the~~ current and untried proposals in the U.S.A. is for the "Magmamax" process which (at present) typifies the use of a binary cycle with a probable modular capacity of 10,000 kilowatts each.

The "Magmamax" system requires the use of a secondary fluid, in this case isobutane, to extract the heat from a "dirty" geothermal fluid in a boiler and to expand the pressurized vapor in a specially designed turbine to produce electric power. The respected pioneer in the U.S.A. geothermal field, Magma Energy, Inc., has joined with the San Diego Gas and Electric Company to construct a research facility at the Salton Sea to study the use of large quantities of hot brine with total dissolved solids reaching the range of 30% - 300,000 parts per million.

ANOTHER RUSSIAN TRIAL

The USSR has also reported some important information on another binary, or two fluid, cycle for a geothermal application. While the entire Western hemisphere has no working, or test, binary cycle geothermal power plants, the Siberian Branch of the USSR Academy of Science has reported on actual operating tests at Paratunka, Kamchatka.

Freon vapor is generated with hot spring water at 181° F. to 197° F. The vapor is delivered to a turbine with some superheat at a pressure of 196 psig (13.8 atmospheres) and condensed with, 59° F. water. This plant is small - in the range of 750 to 1000 kilowatts. It has the especially interesting capability of becoming no more complex than our commonly used centrifugal refrigeration units. Managing a plant of this kind would certainly present no problems for plant engineers in the U.S.A.

FARMS AND INDUSTRY COMBINED — A WAVE OF THE FUTURE?

The Siberian power plant also supplies thermal water to what I would like to term "**Agro-Geothermal Production Facilities**". This may offer the most valuable social-economic potential for both geothermal and hydrothermal resources since it combines power and heat for industrial facilities - and matches them to food production in a world of high priced energy. Hydrothermally heated greenhouses are already used in the U.S.A., Iceland and Hungary.

Studies of potential agricultural complexes and total energy requirements show a similarity between the requirements of our Western U.S.A. desert areas and the "developing countries". As fuel prices rise, portions of the western agricultural system must necessarily turn to the low temperature hydrothermal sources.

Many agricultural products can accept hydrothermal and processed water between 50° F. and 100° F. Cucumbers, lettuce, tomatoes, endive, etc., seem to like this range of temperature. The TVA and the University of Arizona conducted experiments with diesel exhaust heat for greenhouses. Farm animals and poultry showed improved growth in certain temperature ranges. The State of California has warm water fish hatcheries. Catfish grow well and have been produced commercially with warm spring water.

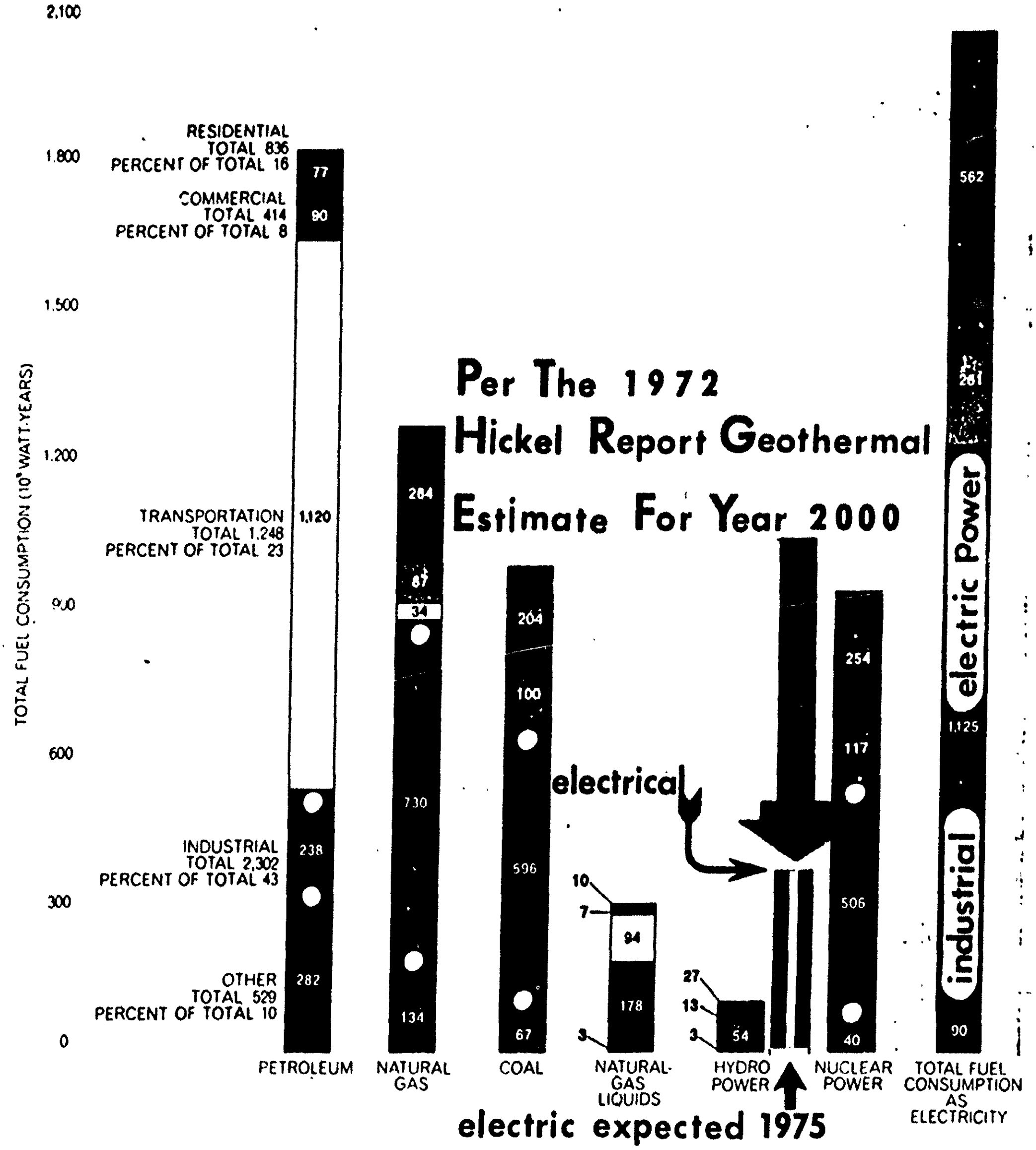
The approaching 1980's may bring many of these agricultural-industrial complexes, which, out of necessity, may be huddled around geothermal and hydrothermal sources of heat to use this energy where it is available and probably where the electric power generation capability will be low. When the money value of this heat is right, its use will be mandatory.

PROGRESS VERSUS INGENUITY

In making haste, and if a government sponsored "crash program" develops, the geothermal research should be handled calmly and wisely lest its value be overestimated in the face of technical reality. Some progress is going to get into social and political territory and face opposition from people concerned about our world in general, and from those who are earnestly opposed to change - needed, or not. At the same time, any possible gross pollution of any kind can no longer be permitted in a maturing world.

There must be ingenious readjustment. For example, in Japan the geothermal power stations are rather neatly incorporated into park areas. If we are to have a fuel starved U.S.A. should there be a smokestack in a National Park where huge volumes of hot water are dumped into the streams ? Fossil fuel is hauled for miles to be burned at Yellowstone Park.

When a pinch comes, can our thinking adjust to a change in the procedure ? The idea prevails today that we may only "look" in the interest of esthetics - and allow the waste of Nature's gift. Already there may have been proposals to drill geothermal wells, out of the visitor's view, to heat the park buildings, and the time may come



PROJECTION OF ENERGY USE — U.S.A. YEAR 2000

when such ingenuity will be a typical requirement.

There are many points of concern to face. The earth's inner heat seems to be just about inexhaustible - but how much of it can we reach ? It is not very close generally. Even when tied into a "dry rock" source, a superheated hot water line 30,000 feet long and buried in the earth offers a few tough engineering problems.

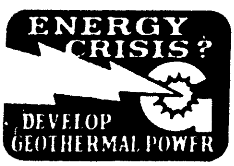
It is not the purpose of this review to explain the various types of geothermal phenomena and the reasons why it is readily available in some places and not in others. Still, it must be made clear that all present thermal manifestations and reasonable sources for geothermal utilization are completely tied to the hydrological system of the earth being available with sufficient water to transport the earth's heat to the surface. . . . Volcanoes excepted.

MANAGEMENT NEEDED

Responsible management of all geothermal and hydrothermal resources will tax the skills of the technical, engineering and scientific communities for some time to come. The history of the management of the world's water supplies is not a reassuring one. Many of us remember the passing of the free flowing water wells, and the, one time widespread, use of well water for "free" air conditioning - and some of the problems that went with the use of that well water. We cannot safely predict that experiences with scaling, corrosion, failure of wells, loss of supply and land subsidence will not be the lot of the plant engineer with widespread use of the earth's heat sources.

We shall need this heat , , , , in due time . . . . and who knows to what extent ? The development time is now and plant engineers must expect to be ready for real progress in future years.

Plant engineers will be in the front line of the battle to manage these conditions so as to assure a minimum impact on the face of the earth and yet meet the need of all people for their physical well being - for warmth and food, as well as for power. Legal, fiscal, social and environmental policies will involve each engineer's skill to the utmost as geothermal joins other heat and power sources during the rest of the 20th Century - and a long time after that.



'SNOOPY' TO JOIN NIXON ENERGY PLAN

WASHINGTON (AP)— With the Middle East war casting new shadows over U. S. fuel imports, the Nixon administration enlisted the cartoon character Snoopy today as the symbol for a massive campaign to conserve energy supplies.

President Nixon received a citizen's advisory committee report on ways the public can help ease predicted fuel shortages this winter.

In addition, top administration officials gave Nixon reports on how the government and private industry are moving to conserve energy supplies.

The national energy conservation campaign will seek to cut energy consumption by five per cent this winter. Among the steps outlined were:

—Adoption of cartoonist Charles M. Schultz's character, "Snoopy," as a symbol for a "Sav-Energy" campaign with distribution of advertisements to the media and energy conservation kits to the nation's schools.

—Widescale distribution of energy-saving hints to consumers, including a suggestion that home thermostats be lowered by four degrees this winter to save 400,00 barrels of oil a day - the estimated amount of the winter's heating oil shortage.

—An extensive program to promote energy conservation by the business community, and continued steps by federal, state and local governments to cut energy consumption.

Tests Run on New Prime Mover for Geothermal Power Generation

EDWARD F. WEHLAGE, P.E., Electrical-Mechanical Consulting Engineer

I saw a second and third "lamp" being hung up in the Western Hemisphere's "geothermal firmament" during the month of April. The first, as engineers know, is the older and larger stations at the Geysers installation in Sonoma County in northern California. It was the first successful geothermal electrical power generation facility outside of Italy and New Zealand. Now it has been joined by a major Mexican plant and a tiny test generator. Together they represent the entire geothermal generation industry in the Western hemisphere.

The new additions – a 75,000 kilowatt generator station and the experimental operation to test a new type of prime mover – are located in the hot water and steam fields developed by the Mexican government at Cerro Prieto, Baja California. According to the best information available, no geothermal test site was available in the USA, while Mexican geothermal developers were willing to help with the development by making a site and a well available for the trials. The solution is an unused geothermal well less than a mile from the Mexican generating plant.

The proposed geothermal fluid prime mover being tested is named the "Helical Rotary Screw Expander" by its developer, Hydrothermal Power Company, Ltd., of Pasadena, California. It was adapted for reverse operation from a relatively new type of air and gas compressor developed in Sweden. This unit, the Lysholm rotary screw compressor, has moved into a strong position for large air and gas installations. Now tests of the expander at Cerro Prieto indicate a great potential for practical applications on a larger scale for geothermal power generation.

The small experimental machine was started without fanfare and started immediately to generate electric power. A hot mixture of steam and salty brine began to flow through the unit with the turn of the throttle valve and the expander began to rotate the generator rather quietly. The first indication of power was the lighting of a lamp in an ordinary extension cord – rather incongruous in the midday brightness of the Mexican desert. As more electric load was added to the generator it demonstrated its ability to deliver some 60 kilowatts from a wet and "dirty" geothermal brine that would quickly destroy a conventional steam turbine generation unit.

Background of Development

Roger S. Sprankle, a young California mechanical engineer, has devoted at least three years to the development of the geothermal expander to utilize the hot water energy in the "wet" geothermal fields and to reduce or eliminate problems with erosion and corrosion. Both of the latter have been serious threats to the continued use of conventional steam turbines with "wet" geothermal steam. Sprankle feels, and the test runs seem to confirm, that the rotary expander will eliminate these problems and also permit utilizing much of the heat and energy wasted in the expanding and flashing of geothermal brines to release for a turbine generator.

The relatively small capacity evident at the beginning of the rotary expander development has not attracted utility company interest so far. Probably this lack of concern is an outgrowth of utility preoccupation with large-scale generating units in the range of 1000 megawatts. The present potential of a geothermal expander may be limited to about 7.5 megawatts and by well capacity.

A major problem in earlier attempts to utilize wet geothermal steam has been the inability of steam turbines to accept large amounts of moisture, sand particles, and dissolved minerals. A rotary power producer like the helical expander, which can accept relatively dirty pressurized hot water, will open entirely new areas for research and development for geothermal applications. The hot water decreases in pressure as it flows through the rotors and liberates steam so that the low level energy is utilized and not wasted. So far, tests indicate the basic machine can be readily adapted to different inlet conditions which might be typical at future geothermal sites.

Field observations of its performance leads to a conclusion that the machine does, in fact, operate. Mechanical refinements will be necessary, but larger size generation units appear feasible. In smaller sizes, it may ultimately serve many remote geothermal areas with an urgently needed power facility – literally a "geothermal water wheel." There must be an expanded interest in generation devices of this kind if the USA is to catch up in geothermal development. ▲▲

RELEASE 12/21/73

For more information contact:

INTERNATIONAL SOCIETY FOR GEOTHERMAL ENGINEERING, INC.
P. O. Drawer 4743, Whittier, Ca. 90607
(or telephone: Edward F. Wehlage, 213-699-3780

A UTILITY MARKET WOULD ASSURE EARLY GEOTHERMAL ELECTRIC POWER PRODUCTION

CERRO PRIETO, Mexico: - In an interview and discussion, Roger S. Sprankle, Hydrothermal Power Co., Ltd., of Pasadena, reported that serious efforts are being made by his company to get geothermal electric power on the United States market as soon as possible.

"Give us an electric utility to buy our energy output and we will build a geothermal power plant to produce electric power. Our prototype geothermal electric power generating unit is now operating in the geothermal field at Cerro Prieto, Mexico where the Mexican government has extended its cooperation. Our company has the only geothermal total flow generation unit in the world which is currently in operation using the raw hot water output of a hydrothermal well, without separators and a steam turbine plant. As a result, with our system there is no need to delay while locating and developing a dry steam field for an extremely large turbine power station".

"We are ready with our equipment - you can see it run, touch it and observe a unit in operation. Given a site where pressurized hot water is available, some U.S. and State government cooperation, and a purchaser for the electric power which we can produce, our group will be immediately ready to undertake, finance and develop a power plant for geothermal electric power output".

The backbone of the system is the "Helical Rotary Screw Expander", a prime mover developed for geothermal power production which Hydrothermal is currently demostrating and that is generating electric power for test loads near the Mexican government's 75,000 kilowatt geothermal generating station placed in operation during April 1973.

Geothermal Engineering Society

is proposed for practical applications to assist in developing a new industry

EXECUTIVE DIRECTOR
EDWARD F. WEHLAGE, P.E.

A new technical and professional society has now been established to furnish a working platform for the advancement of applied geothermal and hydrothermal energy. The *International Society for Geothermal Engineering*, Incorporated, is planned to encourage the free interchange of applied engineering data, technical information and knowledge to expedite the growth of a needed industry.

Over the last decade or two, geothermal and hydrothermal knowledge has grown like the proverbial "Topsy" - and with about as much consistency, largely for the lack of a gathering placė. During its infancy it has been a matter of geological curiosity and concern. Now this knowledge is approaching a more mature and urgent status.It ceases to be a matterof geology alone because it must be put to use, in view of the energy crisis.

The scope of work is currently acquiring a working and practical stature which requires an applied technology embracing electrical, mechanical, civil and structural engineering technologies. It is distinct, in that its nature embraces a degree of "geothermal art" which might be well defined as "science applied", yet requiring a special understanding of its peculiarities.

The need for a technically oriented organization (aside from any potential benefit for the industry) functioning on a wide basis has been accentuated by several occurences during recent months when editors and advertising directors have given less than favorable attention to the potential of geothermal and hydrothermal energy for future needs.

In each instance, when challenged, **THE ANSWER HAS BEEN THAT THEY WERE NON-TECHNICAL REPORTERS CAUGHT IN THE MIDDLE OF ARGUMENTS AMONG EXPERTS.** One answer to this information gap is a working society dedicated to filling that gap about practical use of this type of energy.

The basic aims of the corporation are fourfold:

1. Observe, record, visit and accumulate information and history of past, current and future geothermal and hydrothermal developments in the light of applied technology, scientific research and the effect on social and economic spheres - augmenting, but not replacing the work of other groups - especially the irreplaceable geological activity. Coordination with other energy source applications will receive serious attention.
2. Endeavor to provide a common meeting ground for technical, scientific, economic and political views related to geothermal and hydrothermal usage through a free interchange of knowledge and information.
3. Endeavor to build a working library of publications, books, papers exhibits and other materials relating to the use of geothermal and hydrothermal energy, and make it available to those associated with the society. If possible, this would be accomplished in cooperation with established central engineering libraries to provide maximum access.
4. Present data, furnish information and assist editors, legislators, researchers, and others with sound, factual geothermal and hydrothermal data and background materials to encourage sound development and growth in this type of activity.

The Board of Directors of the Society will work with others and the Geothermal Engineering Foundation for the purpose of acquiring funds and sponsorship to carry out independent and contracted research or development for geothermal and hydrothermal applications, methods and machines. The award of high school, college, & university scholarships and similar activities would be one of the ultimate goals in this phase of the Society. Political effort and lobbying for legislation will not be involved.

The organization is established to function as a non-profit corporation under the laws of the State of California. Work is in progress to secure a tax exempt status under the regulations of the Internal Revenue Service.

Active cooperation with other societies in the many related disciplines and activities will be a part of the basic philosophy of the Society to accomplish the most effective utilization of all efforts in the scientific, engineering and educational advancement of the energy application. *[Cont'd next page]*

Several types of membership will be used to make the work of the society available to the greatest number of interested people. Appropriate membership certificates will be issued upon acceptance of applications by the Board of Directors.

These memberships will be non-voting, except in the authorized chapters or subdivisions and the affairs of the Society will be conducted for an indefinite period by the Board of Directors established with the initial incorporation. No general, widespread meetings will be scheduled until the organization is firmly established. Efforts will be made to secure publications, etc. for all participants at a special price.

Inquiries are welcome. The form below is for your convenience.

INTERNATIONAL SOCIETY FOR GEOTHERMAL ENGINEERING
P.O. DRAWER 4743, WHITTIER, CALIFORNIA 90607

PLEASE SEND SOCIETY INFORMATION AS AVAILABLE FOR MEMBERSHIP

NAME

ORGANIZATION

MAILING ADDRESS

CITY **STATE**

TELEPHONE **COMMENTS**

WILLINGBORO, N.J., *December 11, 1973.*

MICHAEL STERN,
Staff Director, Senate Finance Committee,
New Senate Office Building,
Washington, D.C.

DEAR MR. STERN: The Senate Finance Committee should not only fund clean energy sources such as solar and geothermal energy, but should also stop huge sums of money given to the Atomic Energy Commission. The AEC represents a gross empire feeding on its millions of dollars with no regard to citizen or resident groups—fighting or living near proposed atomic plants. They represent the worst liaison with vested interests, the power companies, as evidenced in scandalous private campaign funding by vested interests.

As well as spending money—my money—why doesn't Congress make policies of design with nature instead of against it? All these glass skyscrapers lose more heat in winter and need more air-conditioning in summer. Can't even open windows in many new buildings on a comfortable spring or fall day. Ventilating machinery goes on no matter what the climate.

Let's have a policy against the horrible signs along our roads. Drivers shouldn't be driving so fast that they can't see a gas station a mile ahead anyhow.

I resent the tax writeoff big oil companies have received as they all built too many gas stations in one area anyhow.

I resent Con. Edison's dam and disfigurement of Storm King Mountain on the Hudson in New York.

I don't think environmental or aesthetic values have been any more respected by our power or oil companies than my pocketbook.

Yours truly,

NANCY C. JACK.

Kansas City, Kans., December 9, 1973.

Re Proposed Energy Trust Fund.

MICHAEL STERN,
Staff Director, Senate Finance Committee, Subcommittee on Energy, New Senate Office Building, Washington, D.C.

DEAR MR. STERN: I am very much in favor with what I understand to be provisions for the establishment of an Energy Trust Fund.

Please apprise me of any additional hearings you have scheduled. Unless one is held in or anywhere near metropolitan Kansas City, I probably cannot appear in person due to considerations of time, money, a full-time job, and the gasoline shortage. In the absence of my physical presence, let this be considered a statement, and let me know if further statements would be useful at some future time. First class postage will increase soon, but the mail still flies cheaper than I do.

A proposed Energy Trust Fund to deal with the nation's energy problems could be a good thing. Studies doubtless will be made to determine if such an entity is necessary, or whether its intended functions and purposes could be assumed by some existing agency or arm of our Federal government. In any case, the idea merits the necessary assessment of its value.

Thin voices predicting an energy crunch for the past five years or so have been dismissed lightly as those of nuts and extremists, and they are without honor now that we have a full-blown energy "crisis." In fact, those who had the temerity to predict an energy shortage now are being blamed for it, and the demand is being made of them "Why didn't you tell us?" Very unfair.

Your Senate committee and Energy subcommittee *know* far more than I *suspect* about such things as wellhead prices, oil import quotas, subsurface mining safety and performance regulations, the environmental destruction of strip-mining, the availability of emission controls on fossil fuel powered generating plants, and a host of other things.

If nothing else, the current energy problem is forcing us at all levels of concern to look at alternative sources of *electrical* energy, of which there appear to be many. Of all the natural sources of energy there are, in fact, it seems rather strange over the long view that we have not seriously as a nation even considered sun, wind, tide, geothermal and other real potentials. In a quarter of a century and with billions of tax dollars, we have well nigh proved that the promise of atomic power was at best illusory, and in practice, inefficient and hazardous to life.

We need not perpetuate our unfounded hopes, mistakes, cost-over-runs, national pride or scientific failures, however.

No one got excited over mere energy "problems," but now that we have an energy "crisis," activity to ward it off has increased. Until very recently, however, most efforts aimed at heading off the energy crisis have been of the "wrong" kind—levering up prices and finding additional deposits of fossil fuels we know are in finite supply and extractible at terrible cost to our environment. Such obvious sources of real electrical generating power as sun and wind have been ignored deliberately by our entire power industry heretofore. The industry now has the incentive to seriously explore alternative sources, and again with help from the Federal treasury. Not nearly as much Federal help, I hope, as has already been expended to induce power companies to buy atomic reactors.

For so long, I have heard it said that technology exists for almost anything you can name, and yet, so much of this alleged existing technology is not being used that it must be considered a national waste. All this talk about our vaunted technology and our brilliant scientists, and yet today, we have an energy crisis? Clearly, something is amiss.

On the anniversary of the Japanese bombing of Pearl Harbor, the Senate voted a staggering $20 million—no, $20 billion—for the non-nuclear R&D of alternative sources of energy. I trust that we can afford this sum over its intended 10-year period, but also trust that we cannot afford not to spend the money for this purpose.

Oil presently lubricates our industrial machinery, runs our cars, and is the basis for a petro-chemical industry which only a trained chemist understands. For the rest of us, there is no similarity between a quart of motor oil and a plastic bag. Oil also heats homes and factories, construction and farm machinery, and I don't know what-all else. Use of oil and natural gas to generate electricity is not its highest or best use. In all the energy crisis flap, hardly anyone makes any distinction between the use of oil for those functions which oil and oil alone serves best, and these which could and should be provided by electricity derived from non-fossil fuel sources.

But finally, because of a "crisis," apparently we are going to get adequately funded R&D of the previously ignored free and highly renewable, inexhaustible sources of electrical energy which do not ravage our land or pollute our air and water. I have to say Amen, and God-speed—at last a fitting use for my tax dollars.

In addition to the foregoing, my one great hope is that with new sources of energy, we will not be encouraged and subsidized into wasting them as we have been in the past. Energy conservation must remain a strong and viable part of any overall plan. Thank you for any and all opportunities for public comment.

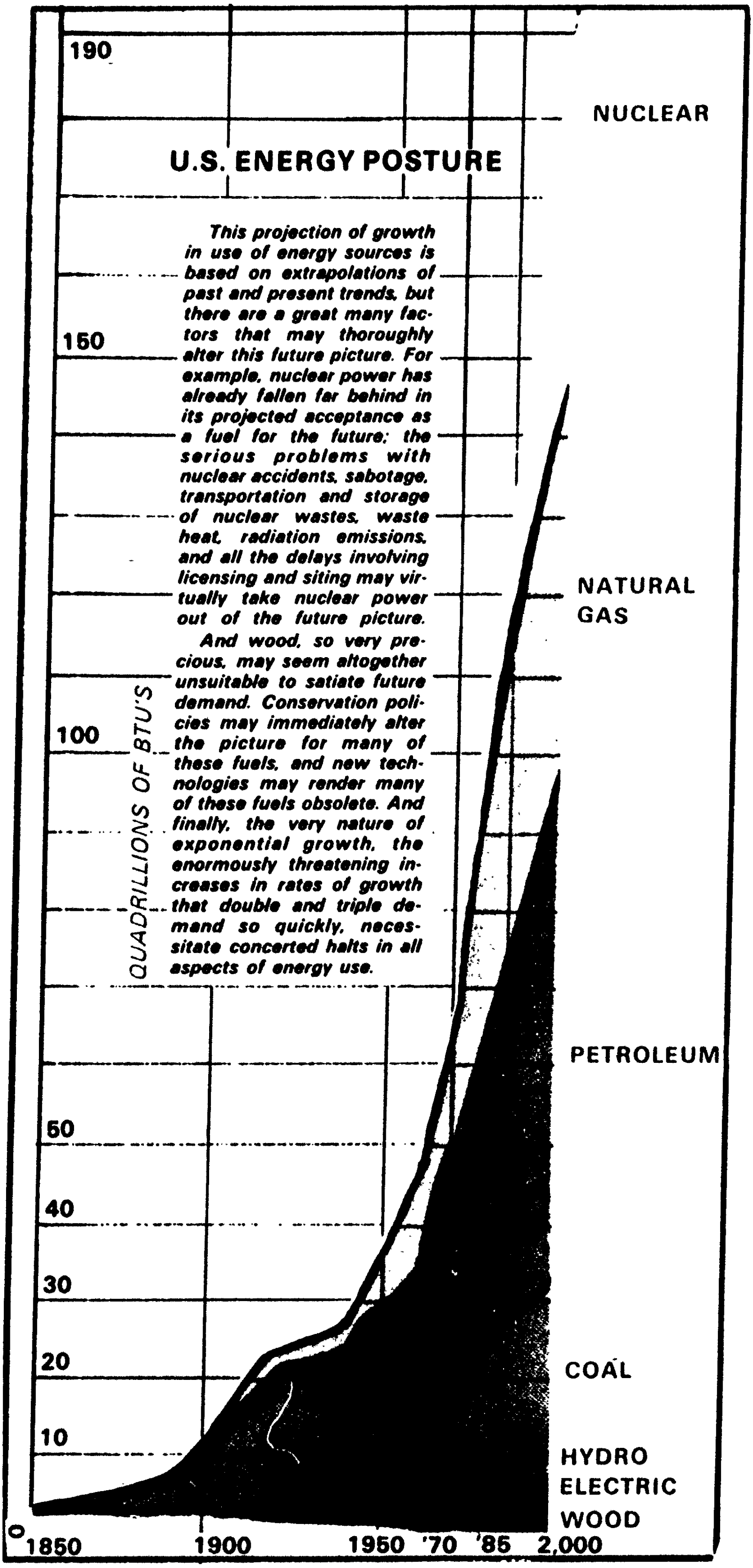
Sincerely,

Miss NANCY C. JACK.

[This presentation is adapted from Energy Options For Man, a public energy alternatives study, produced at the request of Mr. Ralph Nader, by the Environmental Education Group. EEG is a non-profit, tax-exempt, scientific, research and educational public foundation.]

ENERGY OPTIONS FOR MAN

Between now and 2001, just 30 years away, the United States will consume more energy than it has in its entire history. By 2001 the annual U.S. demand for energy in all forms is expected to double, and the annual worldwide demand will probably triple. These projected increases will tax man's ability to discover, extract and refine fuels in the huge volumes necessary, to ship them safely, to find suitable locations for several hundred new electric-power stations in the United States (thousands worldwide) and to dispose of effluents and waste products with minimum harm to himself and his environment. When one considers how difficult it is at present to extract coal without jeopardizing lives or scarring the surface of the Earth, to ship oil without spillage, to find acceptable sites for power plants and to control the effluents of our present fuel-burning machines, the energy projections for 2001 indicate the need for thorough assessment of the available options and careful planning of our future course. We shall have to examine with both objectivity and humanity the necessity for the projected increase in energy demand, its relation to our quality of life, the practical options technology provides for meeting our needs and the environmental and social consequences of these options. ("Energy and Power," Scientific American, 225:3 (Sept. 1971).)



Adapted from Fortune (Time Inc.) The Energy Joyride is Over 1972

Many millions of years ago, the generous earth laid down thick deposits of organic material that, under pressure and heat, were destined to become the fossil fuels—coal, oil, and gas—that are so precious today. At one time, these fossil fuel deposits seemed endless. Today, tragically, we are learning that they are far from infinite.

Some interesting statistics:

"The energy industry of the United States has achieved an average annual growth rate of approximately 3 percent over a century. Expressed in per capita terms, energy use grew from an average annual increment of 1.2 percent for 50 years beginning in 1880 to an average annual increment of 2 percent for the next 30 years to an annual average of 2.7 percent for the last decade, and to a 4.9 percent annual increment in the last five years. Energy use per dollar of gross national product (expressed in constant dollars), which had decreased slowly since 1920, has been increasing since 1967.

"The long term growing demand for energy has been accompanied by major shifts in primary fuel usage. Wood was the major fuel in the middle 1800s; this shifted to coal in the late 1800s and early 1900s and to oil and natural gas by the mid 1900s, and these fuels are expected to be the dominant energy source into the early 2000s." (Technology Review Oct./Nov. 1971, David C. White, "Energy, the Economy, and the Environment").

But at present there is a new development. Many industrial nations today are threatened with power shortages, and the United States where but 6 percent of the population uses 35 percent of the world's energy, is particularly vulnerable to any energy shortening. Today's present shortages are but previews of the far greater shortages to come as fossil fuels (by the end of the century by projections), becomes extremely scarce. Americans facing these preliminary shortages find all this hard to believe, because for so long they have enjoyed abundant energy at low cost. Hoyt C. Hottel and Jack B. Howard of the Massachusetts Institute of Technology have pointed out this: "Total U.S. Energy consumption . . . in 1970 [was] equivalent of 80 slaves working for each one of us to maintain our modern, affluent way of life."

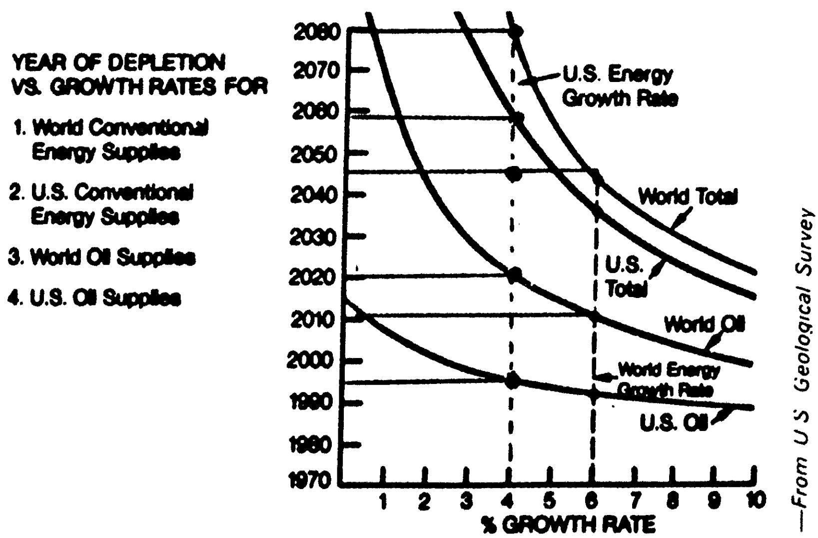
The energy shortage is complicated by the ever present menace of pollution. Corrosive gases, waste heat dumped into waterways, stack emissions, radioactive release, all the effluents and discharges attendant to modern power generation, add extra weight to the cost of energy.

Former chief of the Energy Policy Staff at the White House, S. David Freeman, succinctly notes: "Americans as a nation no longer feel that we can produce and use energy with total disregard for its effect on the environment." Pollution can be controlled, but often at high cost. Frequently the best means of controlling pollution is to switch to cleaner fuels, but even the cleaner fuels are now in short suply. We are beginning to see the bottom of the barrel for many fuels, and the bottom looks very grim."

In the past hundred years, overall demand for energy of all kinds in the United States has increased by a factor of twenty. The rate of increase, encouraged by past energy abundance, is sharply accelerating, especially for electricity. Utilities expect consumption of electricity to double within the bounds of this decade, and almost to quadruple by the following decade of the 80s. Many of these projections are based on extrapolations of past demand. There is a great body of evidence that these patterns will change as the price of energy rises and the public embraces a conservation ethic. Therefore, the great rush for power plants of current design, including nuclear, to meet enormous projected demands should be questioned—especially when we commit ourselves to long range plans that promise environmental dangers. But regardless of the exact figures that form the projections, growth will occur. And we already have an outstripping demand.

Renewable vs. Nonrenewable

The energy used in the underdeveloped nations today emanates from plants and animals: food and wood, dung, and animal power. Water power and wind power are locally important. The vital nature of these energy sources is that they are all of the renewable kind, limited by rate of supply rather than by total quantity available. The energy used in the developed and overdeveloped nations is overwhelmingly from the fossil fuels: coal, petroleum, and natural gas. In the United States, approximately 90 percent of the energy input comes from these sources. The important factor here is that this form of resource has no theoretical limit on the rate at which it can be consumed, but there is a finite limit on the total quantity that can ever be used. Throughout most of the history of man, as an identifiable species, man has relied on renewable sources of energy for food, heat, protection from other animals, to power such innovations as boats, and mills, to lift water and pull plows. It was but 150 years ago that man commenced, on a significant scale, to transfer from wood and wind, from animals and falling water, to heat and power derived from the fossil fuels (nonrenewable resources). Moreover, this changeover allowed the whole world population to expand enormously on the basis of the rate of energy supply that cannot be maintained indefinitely at the present level, let alone an exponentially increasing rate.



This chart depicts the "years to exhaustion" of the supply of each and all conventional fuels at different assumptions of growth rates of usage. The top curve depicts the life of all the world's naturally occuring fuels at various growth rates. Two particular points are highlighted. If the world continues at its 6% growth rate, all conventional fuels will be gone by the middle of the next century. If the world rate drops to the U.S. rate of 4%, we merely extend the depletion point to the end of the 21st century.

Population is a function of the rate of useful energy supply, whether or not the energy emanates from either resource, renewable or nonrenewable. If the energy comes from renewable resources, the rate cannot rise more than briefly above the rate of renewal, and therefore, populations dependent on renewable resources have a propensity, rather quickly to become stabilized in ecological equilibrium with rate of supply. The population based on the other resources on the other hand is confronted with a much more formidable instability problem. Its rate of usable energy depends not on man's efficiency in extracting energy from a dynamic system continually being renewed but upon the rate he chooses to extract energy from a static system that is not renewable on any time-scale meaningful to him (if it takes millions of years to renew his resources those resources have certainly no immediate impact on his present energy needs). The more he allows his numbers to become dependent on his self-opted rate, the more he faces ultimate catastrophe, which can be mollified only by locating new sources of nonrenewable energy and which can be averted only by finding new sources of renewable energy large enough, and renewable fast enough to sustain his vastly increased numbers.

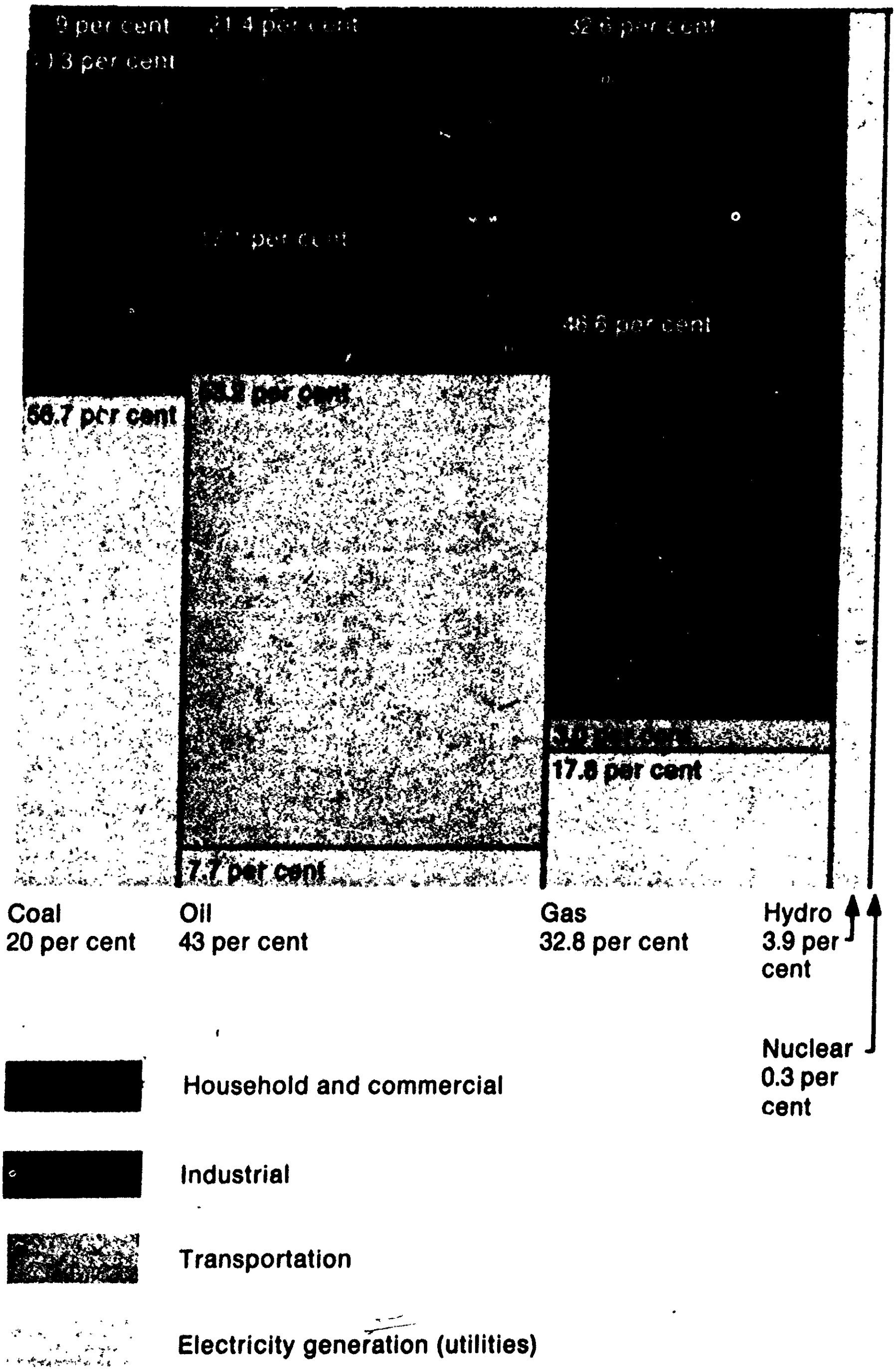
The real crisis is in finding the means of replacing a combustion energy system, based on nonrenewable resources, with a system that will sustain the world population with a clean, continually replenished fuel. There is little doubt that the human population has seriously risen above the ability of existing energy resources (based on present technology) to sustain it very far into the future, and that this unwiedly population faces drastic reduction of its numbers by starvation, pestilence, and warfare unless technology and common sense come to the world's aid.

"The fact—which we are only beginning to confront—is now clear: the probability of finding, or creating by technology, new reserves of nonrenewable energy resources is diminishing. The exploitation of a technological breakthrough such as the fast breeder, which breaks out of the short-term fuel constraint, will be limited by environmental factors. We must plan, and hope, to replace our mined-energy economy, and while we continue to seek adequate replacement systems through scientific and technological effort, we need to consider reducing both our appetites and our numbers in case technology simply presents no alternatives. And we should remember that for millions of starved and starving people in the world, it is already too late" (Technology Review, Dec. 1972, Earl Cook).

In order to prevent catastrophe in the near future, some new and major source will have to be found. This energy project attempts to present many of the alternatives that can serve to supply large amounts of energy, with less danger environmentally, to maintain a high standard of living for the entire world population. Many of these alternatives may be important locally, and many of these sources may be used in combination with others to sustain total energy needs. We should choose now to make the institutional changes necessary to control our energy fate before it controls us in the form of catastrophe.

This double bar graph, divided vertically according to category of energy use and horizontally according to fuel source, shows quantitatively the relative contribution of a particular fuel to a particular end use, by the area of the labeled item. For example, coal contributes 21.4 percent to the total energy input (bottom of left column), and coal use by public utilities to generate electricity is 53.5 percent of 0.214, or 11.4 percent of total U.S. energy use.

—Technology Review, M.I.T



BEST AVAILABLE COPY

When Albert Einstein postulated that mass was energy in a different form an entirely new conception of the universe confronted mankind. $E=Mc^2$ meant that all mass was simply an association of the essential material of the universe—ENERGY. Not only energy in the form of heat and light, but also all field and wave phenomena, such as magnetism and gravity, are manifestations of the same thing—ENERGY. Since that time man has come to understand that everything—even our own lives—is really a flow of ENERGY.

COAL

Coal is a fossil fuel. It is the result of tremendous pressures that have transformed, organic materials, after millions of years, into a concenerated carbon/hydrocarbon form. We combust coal to release its stored chemical energy. Coal represents 20% of the U.S. total energy uses. Coal is certainly the most abundant of the fossil fuels, with estimated reserves in the U.S. of from 300 to over 600 years. But coal utilization brings with it many negative environmental impacts. The combustion of coal releases tremendous quantities of sulfur dioxide, an enormous health hazard. Furthermore, this burning produces particulate pollution and carbon dioxide (which may in the future bring about serious alterations in climate). There are many devices to control pollution from stacks after combustion and there are methods for the gasification of coal to produce a cleaner fuel. But these are currently very expensive. Also, the mining of coal in deep mines is dangerous and creates health hazards, and the surface stripping of coal damages the land, creating tremendous soil-waste problems, acid drainage, unproductive land, and visibly ugly terrain. Reclamation techniques could restore this land, but proper restoration is expensive. We will have to solve many environmental hazards with coal utilization before we continue to use it as a main source of energy for the future.

PETROLEUM

Petroleum is a fossil fuel, emanating from the conversion of organic materials after millions of years of heat and pressure. We combust petroleum to release its stored chemical energy. With the projected high demand for oil, experts believe that by the year 2000, 90% of the word's oil may be exhausted. Particularly in the last few years, domestic production of this fuel has not kept pace with the rapidly expanding demand. Even the tremendous North Slope oil from Alaska (the Alaskan pipeline) will only sustain the U.S. demand for about 3 years. Furthermore, in order to meet demands we will have to import more and more oil from the very rich Middle East locations. This dependence will have serious political implications, and substantial increases in the cost of this foreign oil will seriously divert international funds and cause balance-of-payments worries. Moreover, in order to ship enough oil, supertankers will be needed and these tankers will need offshore marine terminals. This will involve enormous investments, and with the unpredictability of Middle East politics, there could be great monitary losses.

In order to bypass such problems, we will have to bypass importing such great quantities. One way to achieve this is to locate more oil on this continent in the many commercially exploitable areas still available onshore, and the locations offshore.

Of course, the use of oil also has environmental dangers. The atmospheric pollution from the use of petroleum in automobiles is noticeably adverse. The U.S. Office of Science and Technology reports that motor vehicles accounted for 44% of nationwide atmospheric emissions. Stationery fuel combustion of oil accounted for 16%. On a pollutant-by-pollutant basis, the report states that vehicles give off 65% of the carbon monoxide, 46% of the hydrocarbons and 37% of the nitrogen oxides. And there is the hazard of ocean oil spills and petroleum-related pollution of lakes and streams.

Oil shale could also help increase oil supplies. Oil shale is a limestone-like rock that can be processed to produce oil. But there are still problems to be faced with surface mining, waste, and water use.

The serious impact of oil evironmentally can be minimized through such techniques as hydrogenation to yield sulfur-free fuel gas. And there are emission control devices for autos and industry—but these involve cost and fuel problems, which must be considered seriously.

NATURAL GAS

This gas is fossil fuel—natural gas is a mixture of gaseous hydrocarbons predominantly methane. Barely thirty years ago, natural gas was flared at the wellhead as an unwanted byproduct of the search for oil. Currently it supplies one third of the total energy used by the U.S.—as much as is supplied by petroleum. Spurred by the relative cheapness and the clean aspects of the fuel, the market has oustripped projections. In 1968, for the first time, proved reserves of gas in the U.S. declined while production outran new discoveries. Experts say that the reason for the shortage of gas is that the Federal Power Commission has regulated the price of natural gas so low that it discouraged investment.

With the known and available deposits of gas, there appears to be only about 11 years of gas left in the U.S. at current output. There is predicted to be, though, a large quantity of natural gas undiscovered on the continental shelf (this is currently irretrievable by modern techniques). And unless prices or some such encouragement can bring about dramatic discoveries of gas, the future is dim. In order to increase supplies, a frantic scramble is underway.

One way to get more gas is to import it as liquefied natural gas from foreign sources. This requires expensive tankers and expensive gas. Gasifying coal may produce a great deal of gas. Also, methods to extract methane from organic refuse and waste is promising. As for its environmental impact, natural gas is relatively clean. It is virtually sulfur free and when combusted burns with a clean flame. There are problems with natural gas as it is burned in large power plants. In the high temperatures produced for power generation, high quantities of nitrogen oxides are produced. As for natural gas in the form of liquefied natural gas, there are very definite risks in handling in the form of vapor clouds, fire, and flameless booms. We may have to augment natural gas supplies in the many different methods available to us in order to meet the demand for this clean fuel.

ORGANIC WASTE AND REFUSE

Urban and agricultural wastes commonly considered pollution and health hazards could be converted to methane. This conversion could reduce by half or more the tremendous mass of organic wastes and converse dwindling fossil deposits of methane (natural gas). It is predicted that efforts to convert waste to gas would not outweigh the current costs of disposing of waste and of searching for gas in submarine deposits. Methane is produced in nature by the bacterial decay of vegetation and animal wastes in the absence of air—a process known as anaerobic decomposition. The technology of this digestion is reasonably well worked out.

The potential methane production is more than considerable—the combined urban and agricultural waste production in the U.S. is about 1.5 billion tons annually. Each pound of organic waste yields about 10 cubic feet of methane during anerobic digestion—the combined solid waste could yield 30 trillion cubic feet annually. This amount is half again as much as the current natural gas consumption in the U.S. and would be worth $6 to $9 billion at current prices. It is possible to have methane plants in every municipal sanitation facility to produce this gas. Also, a world-famous authority on the use of waste to produce power sites that it is possible to manufacture small, family-sized methane generators that can make any house or apartment at least semi-independent of external power sources. If these projects can be instituted, we will help to solve both an energy and a waste problem in a very clean fashion.

HYDROELECTRIC

Today, only a small portion of the power needs of most countries is met from hydroelectric sources. Although these sources are clean means of generating power, there are many environmental and societal damages associated with them. Damming inundates vast areas of some of the best lands in an era when we cannot afford to lose such acreage; this form of power generation precipitates a process of backwater sedimentation which, in many cases, spreads indefinitely upstream and into tributaries with damage to good farmland; it is not needed for power because steam-generated power in low-gradient areas is now cheaper than hydroelectric power; it provides an expensive, temporary structure in an average prairie plowland the large dam has a life expectancy of only about 50 years due to rapid siltation. It is inhospitable to wildlife because of rapid siltation which chokes out spawning beds and destroys aquatic vegetation. Probably the most important obstacle in the development of this form of water power is the limitation of use. The growing shortage of natural sites and the high cost of construction rule out dependence on this form of energy in the future.

WAVES

It has been proposed to obtain electric power from waves and tides. Since waves exhibit tremendous power, schemes have been put forth to harness it. One plan is to have each incoming wave force water, by means of valves and a pressure chamber, into a tank above sea level; this water would run a turbine on its way back to the sea. Or a battery of floats would be mounted along the shore, each float connected with the shore by a long boom, and the up-and-down motion of these booms would turn a generator. At present the machinery for such ventures is expensive, but these and other schemes are worth investigating, because there is great potential to produce continuous and clean energy.

SEA GRADIENT (SEA THERMAL)

Insolation at the surface of the seas, plus seasonal meltdown of the polar ice caps by solar energy, creates astronomically huge volumes of warm surface water and near-freezing deep ocean water. The thermal gradient that exists between water at the surface and water 1000 feet beneath the surface can be as large as 45 degrees F. A heat engine could operate across such a temperature differential.

And the Gulf Stream could be an enormous source for such power generation. These engines could produce electricity that would possibly meet many times the projected demand in the year 1980. (Other bodies of water, such as the Pacific, could also be exploited, upon modification of systems.)

There are at least two systems that have been proposed to harness this power. In one, the ocean thermal gradients are used to generate water vapor (steam) or the vapor of some intermediate working fluid such as freon. This vapor is then expanded through turbines to drive generators, synchronized at an A.C. net. The A.C. electrical power is transported along tether lines to anchor points in the sea bed, collected in larger sea bed cables, carried ashore, and transported as high voltage A.C. power.

Another system uses thermal gradients in a vapor cycle to generate direct current. The direct current is fed to electrolyzers which are also fed distilled water, then released hydrogen is transported through a hollow tether to an anchor point in the sea bed, collected in larger in-seabed pipelines and transported then as electrolytically pure hydrogen. The hydrogen is converted to electricity in 10 to 20 megawatt fuel-cell central stations dotted throughout the country along the branching inground pipelines.

CURRENTS

Three scientists, two of them with the Commerce Dept.'s National Oceanic and Atmospheric Administration, suggest that man may one day use the energy of the northward flowing Gulf Stream to spin electric generators in systems the scientists liken to "underwater windmills." The Florida Current, a major component of the Gulf Stream, carries more than 50 times the total flow of all the fresh water rivers of the world. Near the surface, the speed sometimes exceeds 5.5 miles per hour. The total energy of motion of the current could produce about 25,000 megawatts—the output of the largest power plants built by man—if all the energy could be harnessed.

TIDAL

Tidal power is a promising source of power from water. All that is required is a place on the coast where there is a high rise in tide. Then you dam off a natural bay or an artificial basin, so that at high tides the water must run through turbines to flow into the basin, and at low tide it runs through them to flow out. The problems of harnessing tidal energy are formidable, however, because of the very nature of this form of energy. The incoming flood tides flow for about six and a half hours, followed by the same duration of the outgoing tide. Conversion of this energy to useful energy can be obtained only part of the time. And there are other variables involved that limit the use of this energy form.

There are only a few places in the world where the available difference in water level is high enough to generate energy. The world's first tidal-powered electric plant is on the estuary of the River Rance in Britanny in northern France. It ranks as one of the world's great power stations but such areas are very limited. Thus tidal energy is more likely to be a valuable resource only to select areas.

GEOTHERMAL

This power is literally "earth heat." And some of the sources of this heat to be tapped for power are steam, hot water, and hot rock. The earth's heat has a potential to be a valuable source of energy, and is currently in use in some areas, producing a substantial contribution to local energy sources. If but 13% of the total heat from geothermal sources could be converted to electric power, we could produce ten times the world's present average power output. The heat energy stored in 500 square miles of the Imperial Valley equals 27% to 65% of the of the heating capacity of the entire world's oil reserves.

Current studies show that the geothermal sources are large and can be readily exploited. At the Geysers in northern California, generating plants that are powered by geothermal steam already produce 180 megawatts of electricity at costs lower than those for comparable plants utilizing fossil or nuclear fuel sources.

As for hot water sources, plans are now being seriously investigated for using sources of hot water, a much more abundant resource than steam, to generate electricity and to ease the chronic water shortage in the southwestern portion of the U.S. (The brackish waters reaching the surface could be desalinated in the process of generating electricity.)

Geothermal sources are found generally where there is a large intrusion of magma, slightly cooled from past volcanic action, lies relatively near the surface, heating a deep underground reservoir of water trapped in permeable rock. With respect to power, water is critical, for it is the medium that carries the heat to the surface. In the process, the water turns to steam which drives the turbines.

There are two broad classes of geothermal fields. One is the fumerole (natural steam vent) in which heat, pressure and reservoir flow are so balanced that the vent of wells at the surface produce mainly "dry," slightly superheated steam. The second class, much more common, is the hot-spring or geyser system, in which a super-abundant reservoir of high-pressure hot water produces mainly boiling water at the surface, only a portion of which flashes to steam. Another source is hot rock, which does not come in contact with underground water systems. Techniques are being devised to circulate water down through cracks to liberate this heat.

There are environmental problems with geothermal power. Disposal of waste waters from steam or hot water wells could pose a substantial problem, particularly where the water is highly mineralized (minerals in high concentrations can poison fish and other aquatic life). Air pollution is also a problem, since noxious gases often accompany geothermal wells. Martin Goldsmith of the California Institute of Technology estimates that the amount of sulfur released at the Geysers is equivalent to that emitted by a fossil-fueled plant of the same size burning low-sulfur oil, and that at the hot water plant under construction at Cerro Prieto, the sulfur release might exceed that of comparable fossil-fueled plants burning high-sulfur fuel.

There is also pollution from the release of ammonia and boron. Also, injection and withdrawal of geothermal fluids may trigger seismic effects whose nature is not well known. And there are problems of odor and noise.

But there are ways to bypass many of these problems by using different methods of converting the heat energy to electricity. One method uses a secondary fluid to carry the energy (isobutane). And another proposes using thermoelectric devices that would obtain electricity directly from the heat source with very slight environmental danger (proposed by the Environmental Education Group). It should be noted that there is tremendous potential for this resource, and with further research it could be of great significance in supplying energy in the near future on a highly competitive basis.

WIND

Wind is continuously regenerated in the atmosphere under the influence of radiant energy from the sun. Like solar power itself, wind is a self-renewing source of energy capable of producing harnessable power. Windmills have had a long history. Thousands of streamlined windmills have lighted farms or charged batteries in rural America for decades. Yet, the use of windmills on a greater scale has been neglected. The potential for wind power is major. One scientist envisions windmills spread across the Great Plains that could supply half the electrical power of the entire United States.

The basic project now is to design windmills that are efficient and operate at low cost. With better design, wind generators could very possibly become competitive sources of energy. Furthermore, to solve the obvious unpredictability and storage problems of wind-generated power, windmills could be used to electrolyze water in order to produce hydrogen for power. This approach would, in essence, convert wind energy into chemical energy. The hydrogen could then be stored or transported in conventional pipelines.

There is much recent concern about wind power and there are many promising proposals. There are current designs for windmills that are based on aircraft technology and may hold the answer to harnessing wind energy more efficiently. With more research, wind energy could very possibly contribute significantly to our future energy needs.

ALGAE

Fuel can be obtained from the solar energy fixated in algae. When fast growing algae are digested by bacteria, the major product is methane. These plants could be grown and harvested on land, in fresh water ponds, or in ocean areas. It has been suggested that all of the world's energy requirements in the year 2000 could be met by combustion of high-energy plants cultivated on only about 4% of the world's land surface. Note: the algae grown on only about one-fifth of 1% of the land in Minnesota could probably produce power equal to all Minnesota's 1971 electrical power requirements at peak consumption (and this state is very north, where the sunlight is less intense than in the South). The power we could produce by cultivating algae would be additional to the methane which could be produced from the digestion of animal and urban waste by anaerobic organisms. That same waste could be converted to oil instead of methane and could satisfy nearly half of this country's present oil demand. Thus, these two—algae and waste—could work together to solve our energy dilemma. These processes are clean, simple, certain and safe.

HYDROGEN

Hydrogen, by far the most abundant, energetic, and clean of all the elemental fuels in the universe, may well be the decisive technology of this century. From the inexhaustible seas, hydrogen would flow continuously. Hydrogen can be produced by central plants by many of several methods, most prominently by electrolysis, and transmitted in underground cables in the form of a gas. Then, this hydrogen gas may be used almost in the identical manner as natural gas. When distributed, this gas can be burned as a gas in home heating and cooling appliances with but slight adjustments or redesigning. It can be used in a wide range of industrial processes. It can be used to generate electricity in local power plants. It can generate power most efficiently of all if it is used in large fuel cells.

With a range of large and small fuel cells, homes and industries would have the option of generating their own power on the premises. When compressed and cooled to liquid form, hydrogen has about two and a half times the energy by unit weight of gasoline, and with some mechanical modifications, all types of internal combustion engines can burn it cleanly.

Converting to liquid hydrogen would make it possible to nearly double the operating range of jet aircraft on the same weight of fuel. Buses, trucks, ships, and trains can all run on hydrogen with their present engines—using fuel cells would be greatly more efficient. Private automobiles can run on liquid hydrogen.

Whatever form the combustion of hydrogen takes, its only major waste is water vapor, which returns in a short time to the sea to become again the source of hydrogen. Thus a hydrogen economy would revolve on a completely renewable, nonpolluting fuel cycle. And hydrogen is relatively safe. In open air or well ventilated places, leaks or spills diffuse so rapidly, hydrogen being the lightest of all elements, that the risks of ignition or spreading flames are actually less than those for gasoline. In general, it's hardly more hazardous than gasoline or even natural gas, though, having different characteristics it requires different treatment.

Hydrogen, because it burns without noxious exhaust products, can be used in an unvented appliance without hazard, hence it is possible to conceive of a home furnace operating without a flue. The list of remarkable innovations possible with this gas is long. The prospects promise to revolutionize domestic heating and cooking techniques. Furthermore, in power production, hydrogen can be stored and used to even out the daily and seasonal variations in load. And hydrogen can be produced by clean sources of energy such as windpower, solar power and fusion. Hydrogen serves as an excellent and efficient means of transmission and storage for these energy producers. Hydrogen is available, effective, economical, safe, and doesn't pollute—and it will fit into present technological structures without any profound changes in our present patterns of industrial and economic organization.

SOLAR

If 1% of the solar energy falling on the Sahara Desert were converted to electrical power, it would supply all of the world's needs for electrical power for the year 2000 . . . technological breakthroughs are not needed to solve this problem: the means to convert solar energy to electrical power is here today.

The problem is an economic one. (V. Bearinger) Solar energy offers an endless and clean source of electrical power. There are many ways to convert solar energy to non-polluting fuels like methane and hydrogen, and there are also ways to use sunlight directly through the use of solar cells, also called photovoltaics. These devices, which power 90% of our unmanned space vehicles convert sunlight directly to electricity. Since solar cells have no moving parts, their reliability is high and their maintenance is low. With mass production, these devices could be the roofing for our homes in the form of solar shingles. Solar cells, together with other solar-power technologies, could have the capability to meet all of our energy needs with clean, safe systems.

Russia is already experimenting with large-scale solar-cell energy farms—a solar-cell power plant. A totally solar home, including solar electricity, could be built with today's technology (this includes heating and air conditioning). And there are many current projects in which homes are already functioning on solar energy. Thousands of solar water heaters have been installed in buildings and homes in Florida, for example. There are also proposals for orbiting solar power stations in synchronous orbit above the earth that would beam down energy in the form of microwaves to earth. Furthermore, there are proposals for large scale solar farms in the Southwest and massive solar furnaces that would focus sun energy to heat water and dissociate it into pure hydrogen and oxygen (see hydrogen). All solar energy needs to become a commercial reality is more backing in the form of funding by the government—there are no technical barriers to wide application.

FISSION POWER

Nuclear fission—certain heavy atoms, on being struck in the right way by a subatomic particle called a neutron—split into two or more fragments and release energy in the process. The basic nuclear fuel is uranium, another is thorium. A nuclear reactor is a device for the controlled fission of a nuclear fuel. At one time, the world was led to believe that the peaceful use of the atom was indeed a safe and practical answer to solving the energy problems of the developed nations and that the commercial use of nuclear energy was the humanistic harnessing of the incredible power locked in the atom.

Recently, a great deal of information, much of which was formerly suppressed from public view, has brought startling awareness of inherent difficulties, and the real and potential hazards that have accompanied the proliferation of nuclear-engendered power. And what is even more frightening is the fact that the further development of nuclear plants is dependent upon the proliferation of an even more hazardous nuclear facility the breeder (a plant where more fuel is produced than is consumed—but these plants have serious safety problems).

When we first got into the nuclear fission program it was believed that this form of energy would provide inexpensive power and would be safe, clean, and efficient. Nuclear energy in execution has manifested none of these attributes. With regard to heat waste, nuclear plants are less efficient in conversion than are conventional fossil-fueled plants. Furthermore, there is no substantial evidence that shows that nuclear energy has competed economically with other forms of energy. In operation, these nuclear plants are far from clean, producing some of the most toxic substances known to man and releasing them in the form of nuclear wastes. Some of these wastes are discharged directly into the environment in the form of gaseous waste, radioactive gases. Radioactivity is extremely hazardous to health and causes genetic mutation, cancer, and other serious disorders.

Great volumes of liquid wastes are produced which must be stored in tanks, some underground, above ground, and in the water. These millions of gallons of wastes are enormously toxic and are so hot that many times they make their containers boil like teakettles. Radioactive substances must be stored for centuries until they degrade enough to be harmless, while the storage units last but decades. Already there have been serious leaks of these materials into water and land, threatening all of us with disaster. Also, these nuclear plants produce tremendous quantities of thermal waste in the form of heated water that must be dumped into air or water. This waste in the water creates many complications, affecting aquatic life and and nearly every physical property of concern in water quality management—creating lethal and sublethal results in water life.

There are, moreover, dangers in the transportation of nuclear wastes and in the possibility of sabotage and diversion of nuclear materials for use in nuclear weapons. And one of the greatest hazards associated with this form of energy is the possibility of a catastrophic accident in which large amounts of radioactive material will be released to the environment, killing thousands and hundreds of thousands of people.

The emergency core cooling system is the last line of defense in an accident and if it fails, such a disaster is possible—and in numerous tests in laboratories, these systems have failed. And no system in current plants has ever been tested. So they don't know for sure if these systems will work at all in the individual plant.

Suffice it to say there are numerous serious dangers involved in the production of nuclear energy, and that, with all the far more promising alternatives at our disposal, this form of energy should be bypassed for cleaner and safer means of electrical power. An economy based on nuclear power is an economy chained to the perpetual surveillance of nuclear waste and to constant fear.

NUCLEAR FUSION

Fusion power is the ultimate source of energy in the universe and if successfully tapped, could provide for mankind a virtually inexhaustible supply of energy that is virtually pollution-free. It is the promise of limitless energy and low pollution that makes the quest for controlled fusion power one of the most important technological searches in man's history.

One important aspect of nuclear fusion technology is plasma physics. Plasma is the fourth state of matter, different from solid, liquids, and gases. Plasma is an ionized gas. Some of the atoms have had one or more electrons ripped away. A plasma is a mixture of ordinary neutral atoms, ions (atoms that have lost electrons), and free electrons. Those lost electrons are free to carry electrical currents; plasma rather easily conducts electricity. The sun is plasma, and so are all the stars. In fact, almost all the universe is plasma. Plasma can be manipulated by electromagnetic forces, and, under certain conditions, the vast energies locked inside them can be utilized to produce electricity.

One method of releasing this energy through thermonuclear fusion, or the controlled thermonuclear reactor. Fusion energy is the power of the stars. Scientists throughout the world, through various processes, are trembling close to producing fusion reactions in their laboratories. Although fusion energy comes from the heart of the atomic nucleus, it is very different from the fission-type of nuclear energy that is used to produce electricity. In fission, heavy atoms such as uranium are split apart, releasing energy. In fusion, light atoms such as the various isotopes of hydrogen are forced together—fused—to create energy. Deuterium, an istotope of hydrogen, is found in seawater and can be separated from ordinary hydrogen rather simply. There is enough deuterium in the oceans to supply hundreds of times the amount of energy the world now uses for millions of years into the future—if a practical controlled thermonuclear fusion reactor can be built. To achieve this state scientists must achieve a minimum temperature of 46 million degrees K.: the density must be at least 10^{15} ions per cubic centimeter (roughly 10,000 times more dense than sea level air); the plasma must be kept at this temperature and density for about a tenth of a second. This is called confinement.

The key to controlled fusion is the task of plasma confinement, and there are many experiments underway to accomplish this. A few are coming very close. The use of laser-pulsed energy to achieve this controlled fusion is one of the most promising.

The environmental advantages of fusion are numerous and remarkable. Here are some: fusion fuel requires no combusting of the world's oxygen of hydrocarbon resources and hence no carbon dioxide or other combustion products; there are no radioactive wastes in the cycles most seriously contemplated; there is never enough fuel present to a support a nuclear excursion; there is safety in the event of sabotage or natural disaster; the potential exists for fusion systems to essentially eliminate the problem of thermal pollution by going to charged-particle fuel cycles that result in direct energy conversion; neutrons from the reaction can be used to transmute radioactive wastes so as to render them non-radioactive; the ultra-high density plasma directly from the exhaust of a fusion reactor can be used to dissociate and ionize any solid or liquid material—an operational fusion torch could be used to reduce all kinds of waste to their constituent atoms for separation, thereby creating a closed system of resources where everything is recycled and reused, and the list goes on.

If we can harness this energy in the near future, by intense interest and funding, there is great hope to supply an energy source for the world that all nations could develop regardless of their native resources, thereby raising the standard of living of all nations without draining the resources of the world or polluting the environment.

Devices and Methods for More Efficient Energy Conversion

In efforts to increase energy production and reduce pollution concurrently, efficiency is the key factor with respect to conversion devices. "The higher the efficiency of an energy system, the more usable power is produced per unit of fuel, and the less pollution and waste. Conventional steam power plants, after nearly a century of refinement, barely reach an efficiency of 40%; the rest of the energy from burning coal, gas, or oil goes off in waste heat, smoke, and such partial-combustion products, or pollutants, as oxides of nitrogen and sulphur. The steam-generating process, which currently accounts for over three-fourths of the nation's power, is essentially a ponderous three-stage mechanical system. Water is heated to high-pressure steam in a furnace boiler; the steam then spins a huge turbine, which in turn drives a big rotary motor generator, whirling a copper-wire armature through a magnetic field to produce electric current. Energy is lost at each stage, and more is lost in transmission lines. The whole system still reflects nineteenth-century attitudes that the earth's resources are so limitless that we can afford, as the shortest route to the greatest profit, to waste most of them."—*Fortune, 1970*

Almost all the world's energy is now transformed by rotating or reciprocating machines. We couple the energy of exploding gasoline and air to the automobile's wheels by a reciprocating engine. The turbogenerator at a hydroelectric plant extracts energy from falling water and turns it into electricity. Such rotating or reciprocating machines are called dynamic converters.

A revolution is currently underway. We now know that we can force the heat and electricity carrying electrons residing in matter to provide us with energy without the use of shafts and pistons. This is a major accomplishment of modern technology; energy transformation without moving parts—direct conversion. The main advantage of direct conversion devices are high reliability and in many cases higher efficiencies and less pollution.

There is one aspect of energy use that cannot be ignored, regardless of the source of energy, and that has serious consequences with respect to the global environment—waste heat. Whenever energy is transformed from one form into another there is inevitably some loss in the conversion, and this loss is in the form of waste heat. The process of combustion has in the past generated the most dangerous problems with respect to thermal additions to the environment. But all manmade heat is released to the atmosphere or earth, whether it has been used or wasted and, in sufficient quantities, can be of importance climatically. Man is currently heating up this planet, and urban areas (the concentrated energy use and production areas) are noticeably warmer than their rural surroundings.

In the long term view, continued growth of energy use could lead to large-scale climatic changes in 100 years or more. The concern of the near future is on a regional scale where population and energy use will continue to cluster, and where, over hundreds of thousands of square miles, emissions of waste heat will be several percent of the naturally absorbed solar radiation. Such emissions may be sufficient to warm the regional climate, to initiate, intensify, or alter the tracks of storms, or to enhance convection and precipitation—the results are awesome to contemplate—minor shifts in air temperature could radically alter winds, tides, rainfall and seasons, setting off dangerous disruptions in life systems. Therefore, regardless of the energy sources we choose for the future, we must be extremely cautious with respect to the production of waste heat and to the impact of energy use so as to effect better global and local heat balances. We cannot maintain, though, unchecked energy growth—even with the cleanest of energy sources.

CONSERVATION OF ENERGY

Amidst the current concern with ways of producing enough energy to meet the staggering projected demands, relatively little attention has been accorded research on methods of making existing supplies stretch further and drastically lowering the necessity for large power plants in great numbers in the near future. Yet by one widely accepted estimate, five-sixths of the energy used in transportation, two-thirds of the fuel consumed to generate electricity and nearly one-third of the remaining energy—amounting in all to more than 50% of the energy consumed in the United States—is discarded as waste heat.

More efficient uses of energy in various sectors may be achieved in numerous effective and relatively simple ways: electric heat pumps for heating and cooling, solar heating and cooling, proper shielding from sun in residences, architectural and engineering practices that build conservation in, vacuum furnaces, magnetohydrodynamics and the various devices discussed previously, the use of smaller cars that require less fuel and the use of rapid transit, and recycling. Conservation now could prevent blackouts and local shortages now and provide more time to find the correct solutions to our energy dilemma.

The conservation of energy is therefore a worthy and increasingly vital goal in the struggle to acquire energy sources. And, despite skepticism on the part of some observers as to the feasibility of wholesale alterations in consumer habits and preferences, significant economies appear to be possible, many of which involve little or no change in life-styles conditioned to plentiful and inexpensive energy. Both more efficient technologies, ranging from better insulation in houses to more efficient furnaces in industry, and policies that reduce rather than promote the demand for energy, could well play a key role in the last two decades of this century.

WAYZATA, MINN.

TO WHOM IT MAY CONCERN—

I am terrified at the lack of tested safeguards and the possibilities of sabotage, vandalism, burglary, and accident for and to prevent nuclear power-plants. Everyone of us is sitting on an activated atomic bomb. I believe our Country should do all in its power to substitute solar, wind, water—any other kind of power for the nuclear reactor. It's only a matter of time before a terrible catastrophe will overtake us because of the disbursed reactors and stored and disposed of live wastes. When I think of my grandchildren inheriting a radioactive country to live in and all kinds of genetic damages which are forever, I sometimes wish they they never had been born.

There is still time. The bombs have not gone off yet. Let's hurry with deliberation and forethought and defuze it forever.

Please include this letter in the hearing record.

Sincerely,

MRS. ANDREW FULLER.

ENVIRONMENTAL CONCERN ORGANIZATION,
Willingboro, N.J., December 11, 1973.

Mr. MICHAEL STERN,
Staff Director, Senate Finance Committee,
New Senate Office, Washington, D.C.

DEAR MR. STERN: We are rushing the following short statement to your Committee in view of the short notice given us in which to do this.

STATEMENT TO THE SUBCOMMITTEE ON ENERGY

The Environmental Concern Organization feels that the only energy sources that would be compatible with the continued existence of man, the environment and the earth, would be such clean sources as solar, wind, geothermal, and conversion of organic wastes into clean fuels by pyrolysis and hydrogenation or into energy through direct burning.

Fossil fuels are environmentally damaging. The estimated 500 years of coal 100 years of oil and 60 to 75 years of gas in world fossil fuel reserves, indicates that the supply of these is fast dwindling. This fact makes the development and mass adoption of the above mentioned clean and abundant energy sources of the utmost urgency. These are listed in the first paragraph of this statement.

The reserves of nuclear fuel, Uranium 235, is estimated at 20 to 30 years. The still experimental breeder reactor which presents even more dangers to man and the environment than conventional nuclear reactors, could prolong the life of U-235 to 1,000 years. Since nuclear fuel is even more inefficient than coal, it represents a regression in terms of fuel use as well as a greater threat to man and the environment than fossil fuels do.

The technologies needed to mass produce energy from such sources as solar, wind, geothermal, tidal and organic wastes, are presently available. All that is needed to start the wheels going is a co-ordinated effort on the part of Government and Industry to initiate preliminary development for mass adoption of such clean, abundant energy sources. We hope that your Subcommittee will be successful in achieving this important goal.

LILIANE STERN,
Chairman of Air Pollution and Nuclear Pollution.

STATEMENT OF LOTTIE FAIRBROOK, FLUSHING, N.Y.

My children, adult grandchildren and I, about 20 citizens, welcome the establishment of your subcommittee. We are confident that the search for and research on clean energy will be greatly accelerated and we hope that—in spite of the oil shortage—a moratorium on nuclear fission reactors will be possible in the near future.

We are deeply indebted to Senator Gravel for his insight and efforts in this direction and we trust that Senators Bentsen, Dole, Hansen, and Mondale agree with his policies and will be just as active and influential in this field.

We feel that the AEC is not performing its role of a "watchdog" (even though it has improved under chairman Dixy Lee Ray) sufficiently, and that the Joint Congressional Committee on Atomic Energy seems to be more concerned with allaying the fears of the public than with eliminating the hazards of atomic energy.

Until a full moratorium can be achieved, we favor the phasing out of nuclear fission reactors.

HIGHLAND PARK, ILL., *December 10, 1973.*

ENERGY SUBCOMMITTEE OF THE SENATE FINANCE COMMITTEE:

I am writing as a concerned citizen who is in favor of safe energy. Without scientific expertise what I have heard and read about the planned expansion of nuclear power plants throughout the United States is alarming. The arguments in favor of such nationwide construction tend to minimize the possibilities of a nuclear accident—but these arguments all seem willing to *sacrifice* millions of lives and dollars if such accidents occur. Indeed, one power authority was quoted as saying that such accidents "are to be expected from time to time" and that people "will just have to learn to live with them." However, aside from such ridiculous statements the statistical chances of such power plants proving unsafe seem altogether too great as far as the public welfare is concerned.

Now, in the midst of the so-called energy "crisis", which many feel has been manufactured by the oil and power interests so that they might reap financial gain at the expense of a bewildered public, the president has called for rapid expansion and development of nuclear power plants—without further study or safeguards. In the light of the president's difficulties, his loss of credibility and the more than $4,000,000 oil and power interests are reported to have contributed to his '72 campaign—and in the light of the enormous sums those same interests have invested in the future of rapid nuclear development, I feel the whole area of nuclear power and alternative programs must be carefully analyzed before this nation is railroaded into a broad program that may—in the long or short run, prove both costly and disastrous.

I strongly urge that alternate sources of energy be thoroughly considered—especially solar, geothermal and fusion energy—along with coal gasification, before any national commitment is made as to future sources of power in this country . . . and that rigid federal construction safety standards be adopted and enforced in any further construction of nuclear power plant facilities. Also, I urge a nuclear moratorium and an early commercial demonstration of solar heating.

I feel it is time the politics of big business be replaced by the politics of human welfare and that the Congress of the United States bears the responsibility of insuring the rights of all its people over the special interests of a few.

Respectfully,

P. NOÉ.

ALEXANDRIA, VA., *December 6, 1973.*

Hon. MIKE GRAVEL,
U. S. Senate Office Building, the Capitol,
Washington, D.C.

DEAR SENATOR GRAVEL: It is good to know that a few people are exerting themselves in the right direction in the energy field. Thanks to someone I received your November 30, 1973 Newsletter yesterday which contains some little run down on Wind and Solar power. I attended a long session on Alternate Power Sources in Montpelier, Vermont, last August and heard Professor Heronemus talk on Wind power, plus many other papers. Not one word was spoken in favor of Nuclear power. In fact organizations were there getting signatures to work to stop its use.

If you have not seen it you ask your secretary to call George L. Weil, 1101 17th Street, N.W. Washington, D.C. 20036 and obtain a copy of his publication. "Nuclear Power: Promises, Promises." It contains much detail on the grim hazards of such power. Surely the Atomic Energy Commission need to be held in check.

It is difficult to see how a 5 to 13 percent cut in Arab oil import has now grown to 25 percent or more. It is my belief that the oil companies are squeezing us. Several years ago Senator Aiken was concerned about the growing concentration of control of all of our energy resources. I would like to see a full scale investigation into the oil companies. If Watergate strikes at the foundation of our government then the energy situation is like a knife at our jugular. Last night on a TV news report Senator Mike Mansfield noted that the "most secret information in the country" is the financial records of the oil companies. The way things have been handled one might make a good case for nationalizing our remaining fossil fuels.

My feeling about them is expressed on the enclosed sheet, Save Our Fossile Fuels. If you concur I hope you can add it to your interests and help to broadcast my plea.

Respectfully,

PHIL WHEELER.

SAVE OUR FOSSIL FUELS

Fossil Fuels are a one time heritage of the some four billion years of the earth's history. When they are gone, they are gone forever. At the present time they represent 95 percent of the total energy used in this country. Our very way of life depends upon them. Yet they are a finite quantity. Perhaps half of all the petroleum we will ever find has been squandered in the past 50 years. Our present high consumption will use much of the rest in this decade if we do not find substitutes.

However much coal and shale we have they also are finite quantities. The recoverable deposits of coal and shale are only estimates. What we have is forever and ever. If we go after coal and shale to supplement our dwindling petroleum, the havoc wrought on our land in the past will be as nothing to that required to get them in the quantities needed.

Fossil fuels are basic raw material for industry—chemicals, fertilizers, plastics, synthetic fibers, steel production and other products. They are our only abundant source of carbon. They are vital to our food, jobs, recreation and transportation. Liquid fossil fuels are the only fuels presently suitable for aircraft. Without them, all aircraft would be grounded. Liquid fuels are still the best answer we have for personal transportation. Yet much of this liquid fuel is used for heating buildings and firing utility plants where other forms of energy could be used.

Ironically, most of the liquid fuel used today is wasted. Our automobiles waste from 70 to 99 percent of the gasoline they use; utility plants from 65 to 75 percent of fuel oil. The rest of the energy is lost heat which radiates out into space.

Nuclear plants are a grim specter that we may all live to regret. They use but one or two percent of the potential energy in Uranium. Radioactive wastes are an unsolved problem. Safety is in great question. Nuclear breeder plants may be even more dangerous. Some 90 organizations have joined together in the National Intervenors coalition to work to halt work on nuclear plants.

What can we use in lieu of our precious fossil fuels, our literal black gold? The sun or solar energy is one certain long range power source. The sun gives us the wind, thermal differences in the oceans, and energy wherever it shines on the planet. Enough sun's energy hits most buildings to adequately warm them if they are well insulated and a collecting and storage mechanism is provided. A few solar heated houses have been built.

The wind has been used some in the past but has long been neglected. Yet Professor William E. Heronemus of the University of Massachusetts has made studies of Vermont for the year 1980 and parts of Wisconsin for 1990. Even in these cold areas he found that windmills could make them self sufficient in electric power. Batteries or fuel cells would be used for standby power.

If wind alone can supply electric power in these states, surely a combination of the wind and sun collecting equipment for space heating could drastically cut the load on our electric plants, reduce the use of liquid fossil fuel for space heating and utilities, and the need for nuclear power plants with all of their dangers. As fuel prices go up and up, it may be nice to know that the wind and the sun are for free once you are set up to use them.

If you are concerned about energy and a safe future, make your concern known.

RELIGIOUS SOCIETY OF FRIENDS, BARNEGAT MEETING,
Barnegat, N.J., December 12, 1973.

To: Michael Stern, Staff Director, Senate Finance Committee, 2227 New Senate Office, D.C. 20510.

The Barnegat, N.J., Meeting of the Religious Society of Friends, E. Bay Ave., Barnegat, N.J., 08005, submits the following statement for inclusion in the U.S. Senate Finance Committee's hearings on an Energy Trust Fund to deal with the country's energy problems:

As an expression of our religious love and concern for our neighbors-in-the-future, the Barnegat, N.J. Friends (Quaker) Meeting urges the United States Congress to enact legislation leading to the preservation and restoration of the Creation.

Specifically we urge Congress to appropriate funds for worldwide research on and development of energy sources that conserve and do not pollute, such as geothermal energy and energy from sun and wind.

We further urge funds for research on and development of systems for the recycling of the world's wastes (metals, glass, paper, sewage, garbage, manures.)

Let our national and international aim be to leave this good and glorious Creation not worse but better than we found it.

(S) ETHEL R. WOOD,
Clerk.

Appendix C

Fiscal Policy and the Energy Crisis—Briefing Material Prepared by the Staff of the Committee on Finance for the use of the Subcommittee on Energy

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93d Congress } COMMITTEE PRINT
1st Session }

FISCAL POLICY AND THE ENERGY CRISIS

COMMITTEE ON FINANCE
UNITED STATES SENATE
RUSSELL B. LONG, *Chairman*

Briefing Material Prepared by the Staff of the Committee on Finance for the Use of the

SUBCOMMITTEE ON ENERGY
Mike Gravel, Alaska, *Chairman*

NOVEMBER 20, 1973

U.S. GOVERNMENT PRINTING OFFICE
WASHINGTON : 1973

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FISCAL POLICY AND THE ENERGY CRISIS

I. Introduction

The "energy crisis," so long an abstraction of newspaper headlines and Congressional hearings, has become a stark reality for millions of Americans, as well as Europeans and Japanese. Unrestrained consumption, reduced production of domestic oil and gas, and other supply disruptions have created a growing energy gap. Cutbacks in the use of energy, averaging anywhere from 10–20 percent—perhaps higher in some regions—are unavoidable this winter. The duration and severity of the shortages in the coming winter months now depend as much upon the weather as upon remedial public policies.

The Committee on Finance has jurisdiction in the Senate over our nation's tax and trade laws. Changes in these laws may play a major role in alleviating the short term energy problem and in moving toward a policy of developing our nation's huge untapped energy resources over the longer term.

This document has been prepared to furnish background information to the Members of the Subcommittee on Energy in dealing with the following questions:

Should fiscal policy be employed to mitigate the current energy shortage and to assist in the transition to alternative energy sources? If so, how?

Are fiscal incentives needed to stimulate exploration and development of domestic sources of energy?

If so, which would be the most efficient—a tax credit, tax deduction, depletion, etc?

What would be the effects on supply and demand of allowing the price of all fuels to reach their natural level through market forces?

What would be the income distributional, environmental and consumer effects of a tax incentive approach vs. a free market approach?

Given the enormous capital needs to develop fossil fuels and their alternatives, is there a need for both tax inventives and price deregulation?

Is there a need for an "energy trust fund," the monies from which would be used to develop various conventional fossil fuels as well as alternative forms of energy—coal gasification and liquefaction, tar sands, oil shale, geothermal, solar, wind, nuclear, etc.?

If so, how should the fund be financed—consumption taxes on gasoline or automobiles, or production tax on energy at source or some combination?

Who should administer such a fund?

President Nixon has announced a plan designed to mitigate shortages over the near term by reducing demand and encouraging production, and over the longer term by moving toward energy independence." [1]

The highlights of the President's program are as follows:

—Prevent utilities and industrial facilities from switching from coal to petroleum fuels and encourage utilities to switch from residual oil to coal;
—Reduce jet fuel consumption which could curtail airlines flights by 10%;
—Reduce home heating oil consumption by encouraging homeowners to keep their thermostats at 68° Fahrenheit, and by maintaining temperatures in Federal offices heated at between 65°–68°;
—Encourage drivers to use car pools or public transportation whenever feasible;
—Establish 50 mph speed limits;
—Establish daylight saving time year round;
—Relax environmental regulations on a case by case basis;
—Encourage businesses and schools to alter working hours and school schedules whenever possible;
—Open up naval oil reserves at the Elk Hills Naval Petroleum reserves in California;
—Plan for possible rationing or taxation of gasoline;
—Deregulate natural gas prices;
—Speed up energy research and development;
—Enact Alaska pipeline bill;
—Allow surface mining of coal;
—Provide overall planning and coordination through creation of several new energy agencies.

Some of these measures require legislation. Those that involve establishing taxes or "fee schedules" would be within the jurisdiction of the Finance Committee.

II. Defining the Energy Problem

The energy problem cannot simply be defined as a shortage of resources. The U.S. has a large potential resource base of fossil fuels sufficient to meet its needs for several hundred years at present consumption levels. Rather, what exists is a widening gap between

[1] A White House fact sheet describing the President's emergency energy program is reproduced in Appendix A.

energy consumption and the production of available energy supplies. Although the U.S. has large potential energy resources, most of these resources are a long way from development and consumption.

While there is certainly room for error in estimating the size of our energy resources, responsible studies have concluded that our indigenous resources are truly massive. The table below compares the potential resources base with 1972 U.S. consumption.

TABLE 1.—*U.S. Consumption and Resources of Energy Fuels*

Energy fuels	Potential resources	1972 consumption
Oil [1]	346 billion bbls	6.0 billion bbls.
Natural gas [1]	1,178 trillion cu ft	22.6 trillion cu ft.
Coal [2]	394 billion tons	517 million tons.
Uranium [3]	1.6 million tons	16 thousand tons.
Oil shale [4]	189 billion bbls	None.

[1] U.S. Geological Survey.
[2] U.S. Bureau of Mines.
[3] U.S. Atomic Energy Commission.
[4] National Petroleum Council. *U.S. Energy Outlook, a Mutual Appraisal.*

If we developed all oil and gas resources in this country, we would have more than 100 times our 1973 needs. Our coal resources are 600 times current production. But it will take many years and huge amounts of capital to develop those resources.

It has been estimated by the National Petroleum Council [1] that to meet our energy needs between now and 1985, we shall have to make an investment of between $375 and $547 billion in new productive facilities, more than double the rate of investment over the 1960's and early 1970's.

[1] The National Petroleum Council is an officially established industry advisory board to the Secretary of Interior. The estimates on capital financing needs appear on page 296 of the Council's study: *U.S. Energy Outlook: A Report of the National Petroleum Council Committee on the U.S. Energy Outlook.*

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SUMMARY OF CUMULATIVE CAPITAL REQUIREMENTS
U.S. ENERGY INDUSTRIES 1971-1985
(Billions of 1970 Dollars)

	Initial Appraisal	High Supply	Intermediate Supply		Continuation of Current Trends
Oil and Gas					
Exploration & Production	92.4	171.8	144.8	135.1	88.0
Oil Pipelines	3.5	7.5	7.5	7.5	7.5
Gas Transportation	21.0	56.6	46.9	39.8	29.5
Refining*	20.0	19.0	24.0	30.0	38.0
Tankers, Terminals	14.5	2.0	9.0	16.0	23.0
Subtotal	**151.4**	**256.9**	**232.2**	**228.4**	**186.0**
Synthetics					
From Petroleum Liquids	–	5.0	5.0	5.0	5.0
From Coal (Plants Only)	1.5	12.0	4.6	4.6	1.7
From Shale (Mines & Plants)	0.5	4.0	2.2	2.2	0.5
Subtotal	**2.0**	**21.0**	**11.8**	**11.8**	**7.2**
Coal†					
Production	9.3	14.3	10.4	10.4	9.4
Transportation	6.0	6.0	6.0	6.0	6.0
Subtotal	**15.3**	**20.3**	**16.4**	**16.4**	**15.4**
Nuclear					
Production, Processing, Enriching	5.0	13.1	11.0	8.5	6.7
Total All Fuels	**173.7**	**311.3**	**271.4**	**265.1**	**215.3**
Electric Generation, Transmission‡	200.0	235.0	235.0	235.0	235.0
Water Requirements	N.A.	1.1	0.8	0.8	0.7
Total Energy Industries	**373.7**	**547.4**	**507.2**	**500.9**	**451.0**

* Based on maximum U.S. requirements, some of which may be spent outside the United States

† The last four columns do not include capital requirements for coal production for synthetic fuels. These requirements in billions of 1970 dollars are as follows: High supply—2.0; Intermediate supply—0.8; Continuation of current trends—0.3.

‡ Condition 1; capital requirements under all six conditions postulated by the Electricity Task Group are as follows:

Condition	Cumulative Investment (1971-1985) Billion 1970 Dollars					
	1	2	3	4	5	6
Power Plant Construction	181	183	186	169	196	163
Transmission (estimated at 30% of Condition 1 Cumulative Power Plant Investment)	54	54	54	54	54	54
Total	235	237	240	223	250	217

The high supply column suggests the capital required to finance a policy of maximum development of U.S. energy resources between 1971 and 1985. Intermediate supply cases embrace policies which would slow down but nevertheless continue the growing dependency upon foreign resources. The "continuation of current trends" case would result in a dependency upon foreign sources for over 50 percent of our energy needs. Source: National Petroleum Council, U.S. Energy Outlook, December 1972, p. 296.

In addition to these conventional sources of energy, the United States has the technology to develop alternative sources of energy from the sun (solar), the wind, the earth's crust (geothermal), the power of the atom (nuclear fission and fusion), and others. There are already existing facilities to "gasify" coal and liquefaction of coal is also possible. A strong, well coordinated research and development program is necessary to develop these alternatives and to translate their

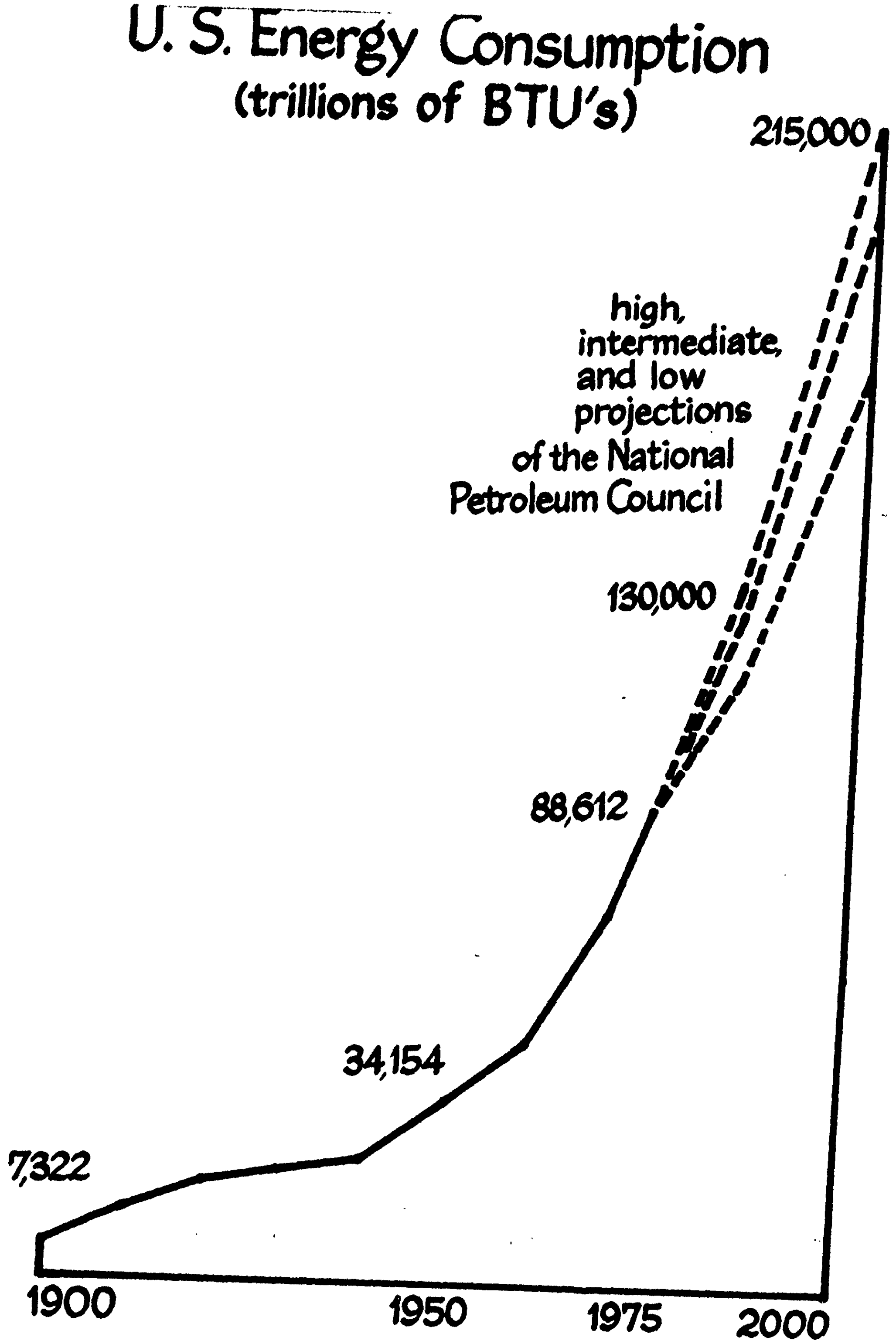
technological feasibility into commercial uses in the most environmentally sensible way possible. These are generally considered longer range solutions and not remedies for the short term problem. The short term problem, it appears, can only be mitigated by cutbacks in U.S. consumption.

With six percent of the world's population, the U.S. ccnsumes almost one third the world's captive energy. The rate of U.S. consumption, moreover, is accelerating, as shown by the following Department of Interior projections:

TABLE 2.—*Per Capita Consumption of Energy*

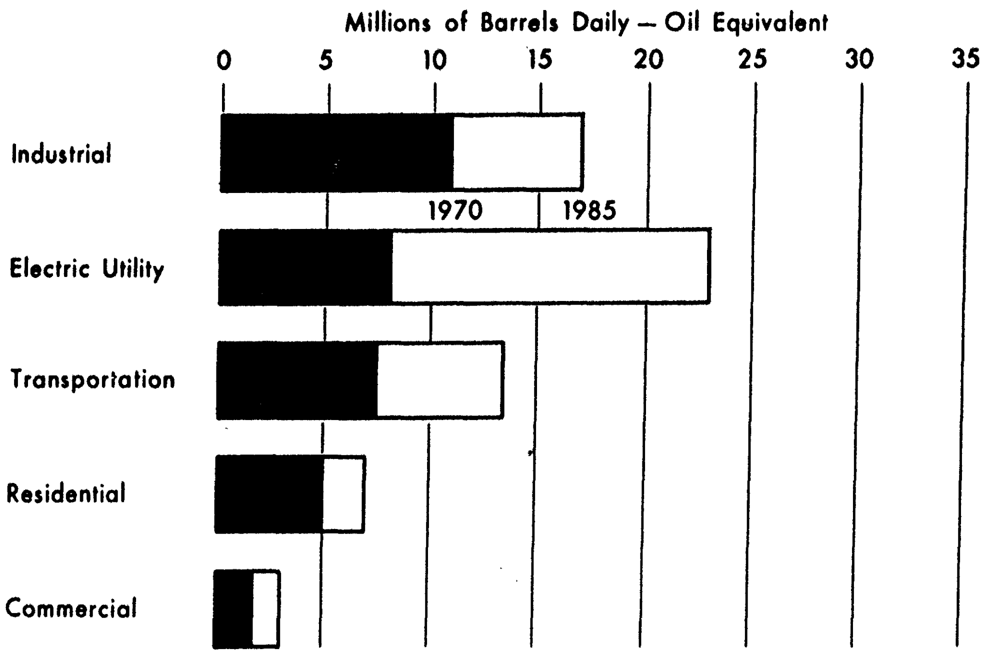
Year	Population (millions)	Total energy consumption (trillion Btu)	Per capita energy consumption (million Btu)
1950	152	34, 154	225
1960	180	44, 960	250
1970	204	68, 810	337
1975	215	88, 612	412
1985	237	133, 396	563
2000	266	191, 556	720

Source: U.S. Department of Interior.


U. S. Energy Consumption
(trillions of BTU's)
215,000
high,
intermediate,
and low
projections
of the National
Petroleum Council
130,000
88,612
34,154
7,322
1900
1950
1975
2000

Consumers of energy in the U.S. fall into five major categories: industrial (29 percent of energy consumption), electric utilities (26 percent), transportation (25 percent), residential (14 percent) and commercial (6 percent). The energy used by electric utilities is converted to electricity and sold to consumers, two thirds to business and industry and one third to residential consumers. More than two thirds of the total energy used in the U.S. is used for commercial or industrial purposes.

ENERGY USE - By Markets



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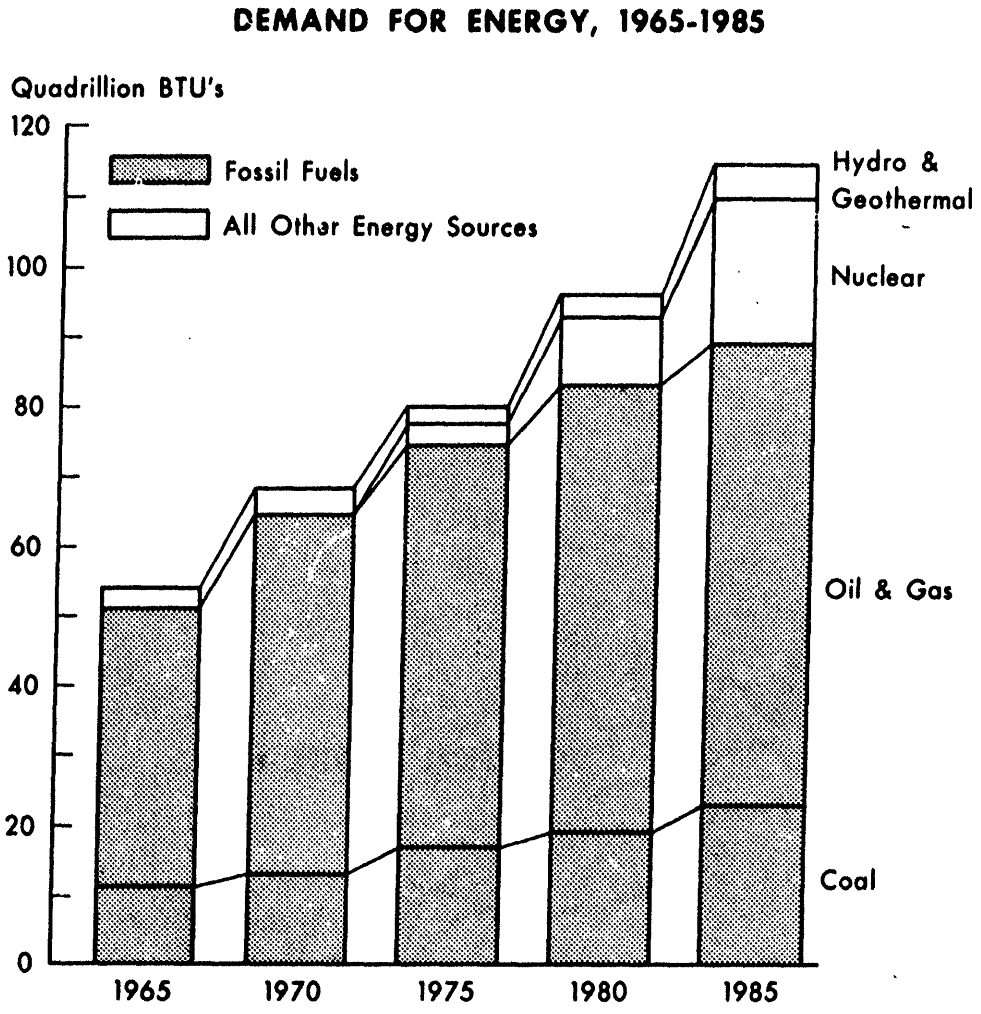
Approximately 95 percent of the energy consumed in the U.S. in 1972 derives from three sources: petroleum (46 percent), natural gas (32 percent), and coal (17 percent). Hydroelectric and nuclear power plants contributed four percent and one percent, respectively, to U.S. energy stocks. Other sources of energy exist in various stages of development and application, but it is considered probable that the U.S. will continue to rely on fossil fuels for more than half its energy through the year 2000. The following table and chart give a breakdown of the U.S. energy mix, in 1970 and projected to 1985:

Table 2. United States demand for energy resources by major sources, year 1970 and estimated probable demand in 1975, 1985, and 2000[1]

	1970[2]	1975	1985	2000
Petroleum (includes natural gas liquids)[3]				
Million barrels	5,367	6,550	8,600	12,000
Million barrels per day	14.70	17.9	23.56	32.79
Trillion Btu	29,617	36,145	47,455	66,216
Percent of gross energy inputs	43.0	40.8	35.6	34.6
Natural gas (includes gaseous fuels)				
Billion cubic feet	21,847	27,800	38,200	49,000
Trillion Btu	22,546	28,690	39,422	50,568
Percent of gross energy inputs	32.8	32.4	29.5	26.
Coal, (bituminous, anthracite, lignite)				
Thousand short tons	526,650	615,000	850,000	1,000,000
Trillion Btu	13,792	16,106	22,260	26,188
Percent of gross energy inputs	20.1	18.2	16.7	13.7
Hydropower, utility[4]				
Billion kilowatt-hours	246	282	363	632
Trillion Btu	2,647	2,820	3,448	5,056
Percent of gross energy inputs	3.8	3.2	2.6	2.6
Nuclear power[5]				
Billion kilowatt-hours	19.3	462	1,982	5,441
Trillion Btu	208	4,851	20,811	43,528
Percent of gross energy inputs	0.3	5.4	15.6	22.7
Total gross energy inputs, trillion Btu	68,810	88,612	133,396	191,556

[1] Preliminary estimates by Bureau of Mines staff.
[2] Latest data.
[3] Product demand - includes net processing gain.
[4] Includes pumped storage, internal combustion and gas turbine generation. Converted at prevailing and projected central electric stations average heat rates as follows: 10,769 Btu/Kwhr in 1970; 10,000 Btu in 1975; 9,500 in 1985; and 8,000 in 2000.
[5] Converted at average heat rates of 10,769 Btu/Kwhr in 1970; 10,500 in 1975 and 1985; and 8,000 in 2000.

Factors in the U.S. Energy Situation



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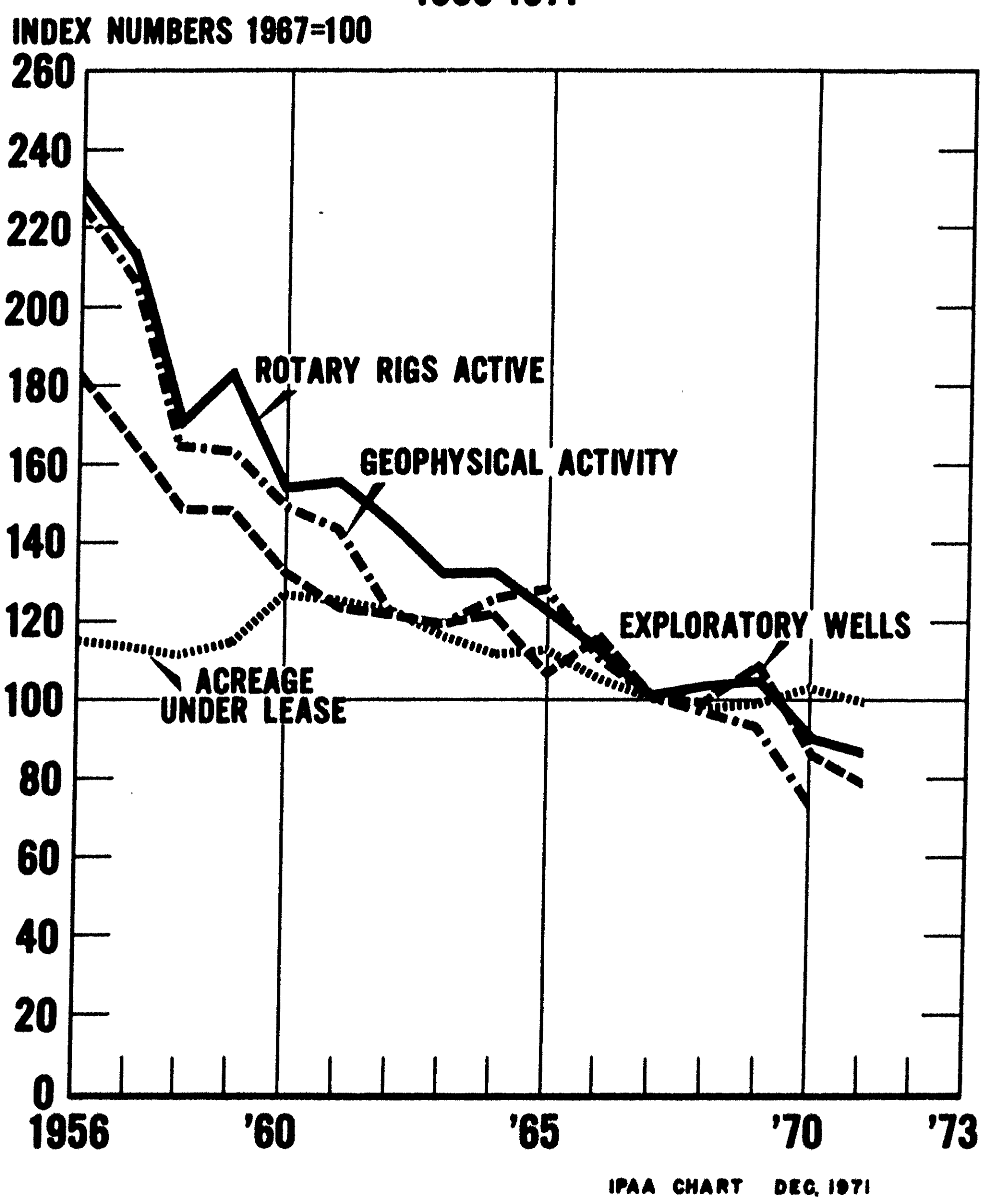
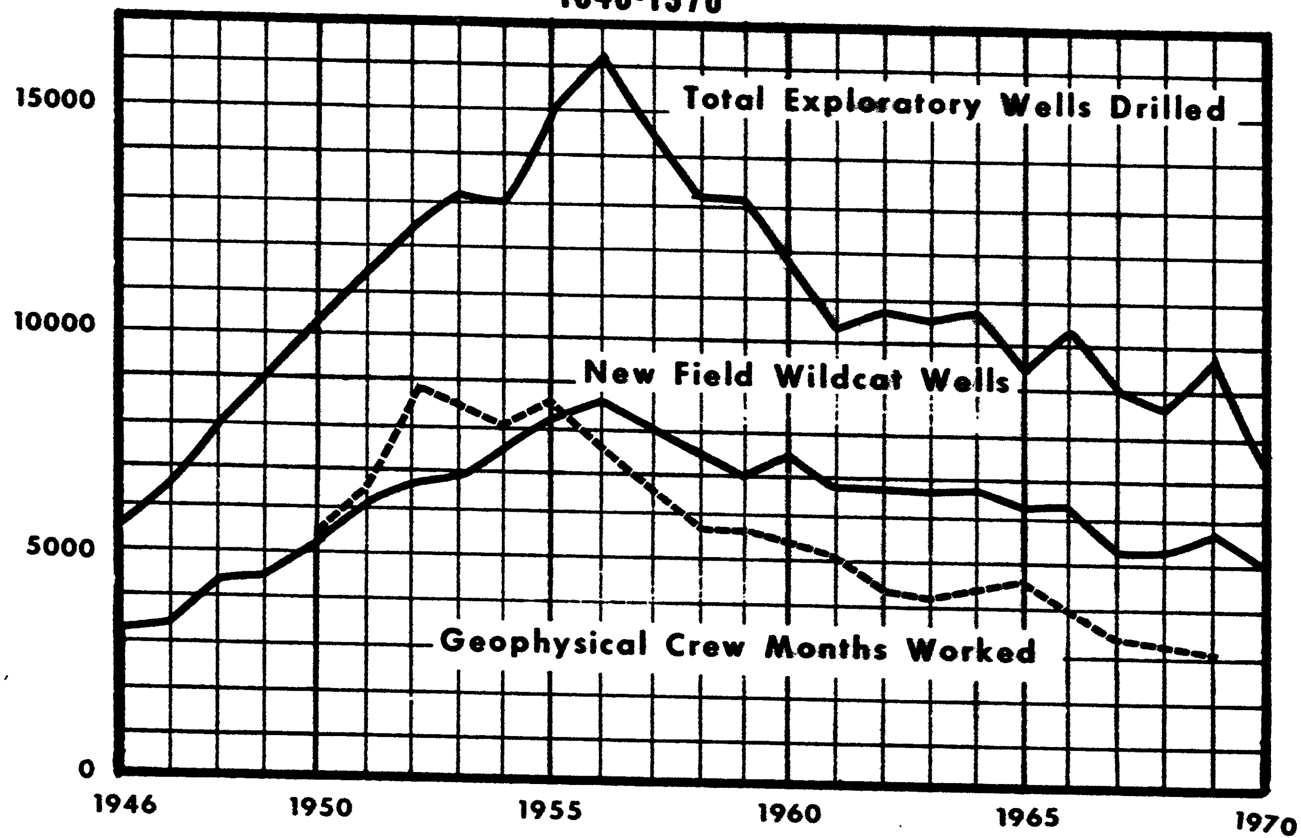
The Conference Board is obliged to Chase Manhattan Bank and the American Mining Congress for permission to reproduce these charts. They appeared originally in the "Outlook for Energy to 1985" (Chase) and the American Mining Congress "Special Situation Report No. 2, May, 1972." See also Appendix 1, p. 241.

Despite its huge energy reserves, the U.S. faces a shortage primarily because domestic production of fossil fuels has peaked. The U.S. no longer has excess crude production capacity. The drilling of oil and gas has lagged. In 1956, the postwar peak year, the industry drilled over 57,000 wells. Last year only 29,000 wells were drilled—we are now almost back to the 1946 level of well drilling. Exploratory activities and the service industries associated with those activities have also fallen sharply as shown in the following charts.

U.S. EXPLORATORY ACTIVITY
1956-1971



UNITED STATES
EXPLORATORY ACTIVITIES
1946-1970



Environmental concerns have resulted in delays in siting energy facilities and greatly increased the need for scarce low sulphur fuels, displacing high sulphur fuels, particularly coal. New discoveries of natural gas have decreased sharply during the past several years. Since 1966, proven natural gas reserves have decreased 21 percent while consumption increased 37 percent. The U.S. is now producing and consuming about twice as much natural gas each year as it is finding and adding to its proven reserves.

Production of domestic crude oil and natural gas liquids peaked in November, 1970, and decreased in 1972 to an average of 11.6 million barrels per day, down approximately 5 percent from the peak.

In 1972, total U.S. bituminous coal and lignite production was estimated to total 590 million tons, down from 603 million tons in 1970. The use of coal has been greatly hampered by competition from lower cost and less polluting alternative fuels, primarily imported residual fuel oil and low-priced natural gas. About 10 percent of U.S. coal production (60 million tons) is exported. Overall production, however, is restricted due to actual and anticipated constraints on domestic consumption of coal. The coal industry estimates a three year lag before U.S. coal production can be significantly increased.

In 1970, energy imports to the U.S. exceeded reserve capacity; thus the U.S. was no longer self sufficient. In 1972, the U.S. reached essentially 100 percent production (no reserve or shut-in capacity) and foreign petroleum imports totaled 4.7 million barrels per day, accounting for 29 percent of the total oil supply.

IMPORTS—NO SOLUTION

For the short and medium term, imports were viewed until recently as filling the gap between development of proven reserves and consumption. While energy projections are notoriously unreliable, it was widely assumed that by 1980 we would be consuming 24 million barrels of crude oil a day, more than half of which would have to be imported. It was also assumed that most of our import needs would be filled by Middle East and North African oil where 81 percent of the proved free crude oil reserves as of January 1, 1973, are located. (See chart below.) That assumption has all but been destroyed by recent events.

Proved Free World Crude Oil Reserves

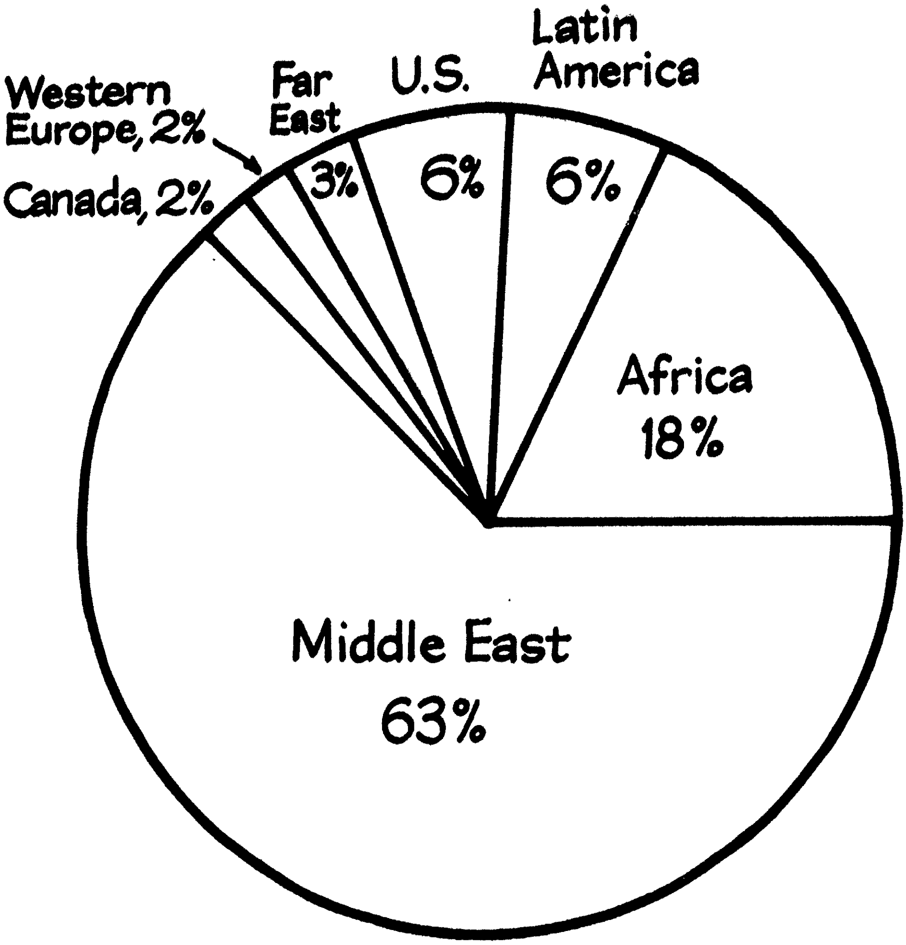


TABLE 3.—*Proved free world crude oil reserves* [1]—*Jan. 1, 1973*

[In billions of barrels]

Area	Reserves	Percent of total
United States	37	6
Canada	10	2
Latin America	33	6
Western Europe	12	2
Africa	106	18
Middle East	356	63
Far East	15	3
Total	569	100

[1] Excluding natural gas liquids.

Source: U.S. Department of Interior.

We will not be able to fill our energy gap with imports from Arab countries in 1973 because of production cutbacks and embargoes. And whatever oil we may be able to import from the rest of the oil producing world will cost us dearly. Europe and Japan are both energy starved and the competition for short energy supplies will drive up crude prices drastically. On October 16 of this year, crude prices were increased 70% by fiat of the producing nations. Thus, no one knows with any degree of certainty what prices of imported crude will be in 1975, 1980, and 1985.

We do know that, in the short run, we face a crunch. Cutbacks in domestic consumption are already a reality. With forecasts of a bitter cold winter, severe hardship to many American households will bring the "energy crisis" home and some frightening possibilities of 20–25 percent cutbacks in fuel consumption are being made.

While the short-run picture is bleak, the longer term outlook is not—providing that this country dedicates itself to a comprehensive energy development program. Such a program may be made consistent with environmental and other goals, but intelligent organization and planning is required for reconciling our energy needs, our environmental concerns, our consumer interests and our foreign policy objectives. Up to now there has been no intelligent and comprehensive planning to reconcile these various concerns into one consistent national policy on energy.

THE FEDERAL BUREAUCRACY

The United States in fact lacks a national energy policy and the U.S. Government lacks the organizational framework with which to implement one. There are presently 64 agencies distributed among nine

Executive Branch departments, 15 independent agencies, and the Executive Office of the President, each concerned with some aspect of energy. Forty-six of these agencies administer programs or implement policies which directly impact the nation's energy system; the other 18 agencies administer programs or policies which indirectly affect the nation's energy system. The President has appointed Governor John Love Assistant to the President for Energy Policy. Yet the office lacks statutory authority over the agencies which actually administer energy programs. On June 29, 1973, the President proposed legislation to establish a Department of Energy and Natural Resources (DENR), a separate and distinct Energy Research and Development Administration, and a Nuclear Energy Commission.

THE NATURAL GAS PRICE REGULATION

Natural gas is of such critical importance to the homeowner, the farmer as well as certain segments of industry that the current natural gas shortage is in large measure most critical energy problem facing the nation. Yet this country has been following a policy whose effects appear totally inconsistent with our energy needs—the Federal Power Commission's regulation of the price of natural gas at the wellhead. MIT's Paul MacAvoy and Robert Pindyck and Harvard's Steven Breyer[1] concluded in their econometric studies that regulation of gas wellhead prices has produced the natural gas shortage that we are experiencing today.

Their study suggests that a phased deregulation would lead to a substantial increase in both reserves and production supply and that excess demand would be significantly reduced in two years and totally eliminated by 1979. These results are shown in Table 4. The study projects that the alternative policy of strict controls (shown in table 5) would result in an increasing gap between production and consumption.

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[1] See Professors Steven Breyer and Paul MacAvoy's article on "The Natural Gas Shortage and the Regulation of Natural Gas Producers." *Harvard Law Review*, Vol. 86, No. 6, April 1973, and MacAvoy and Pindyck's Alternative Regulatory Policies for Dealing with the Natural Gas Shortage, *Bell Journal of Economics & Management Science*, Vol. 4, No. 2. An article by these professors describing the history of the natural gas shortage and the regulation of natural gas producers is reprinted in appendix D.

Paul MacAvoy is a Professor of Economics at the Sloan School of Management at the Massachusetts Institute of Technology and Steven Breyer is a Professor of Law at the Harvard Law School. Professor Robert Pindyck of MIT has joined with Professor MacAvoy in showing the effects of regulating natural gas on the consumer.

TABLE 4.—*The effects of phased deregulation*

Year	Field price on new contracts (cents/M. cubic ft.)	Additions to reserves (trillion cubic ft.)	Production supply (trillion cubic ft.)	Production demand (trillion cubic ft.)	Excess demand over production (continental United States trillion cubic ft.)
1972	26.3	9.8	19.3	23.3	4.1
1973	29.6	12.7	22.1	24.4	2.3
1974	44.1	13.8	25.0	25.4	0.3
1975	47.7	15.4	26.0	26.4	0.3
1976	51.3	18.3	27.1	27.4	0.3
1977	54.9	22.2	28.2	28.5	0.3
1978	58.4	25.9	29.5	29.7	0.2
1979	62.0	29.9	31.0	31.0	0.0
1980	65.5	34.6	32.8	32.4	0.3

TABLE 5.—*The effects of strict controls*

Year	Field price on new contracts (cents/M. cubic ft.)	Additions to reserves (trillion cubic ft.)	Production supply (trillion cubic ft.)	Production demand (trillion cubic ft.)	Excess demand over production (continental United States trillion cubic ft.)
1972	26.3	9.8	19.3	23.3	4.0
1973	29.6	12.7	22.0	24.3	2.3
1974	30.5	13.8	22.8	25.6	2.8
1975	31.3	15.2	23.4	26.9	3.6
1976	32.1	16.8	24.0	28.5	4.5
1977	33.0	18.7	24.7	30.3	5.5
1978	33.8	20.8	25.7	32.2	6.6
1979	34.6	23.2	26.7	34.4	7.7
1980	35.5	26.3	28.0	36.9	8.9

Source: Paul W. MacAvoy and Robert S. Pindyck "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage" *Bell Journal of Economics and Management Service*, Vol. 4, No. 2. Autum 1973, pp. 489 and 491.

In any case, the price controls of the past two dozen years have been accompanied by a steady decline in reserves—output is not being fully "replaced" in the supply line by new reserves—coupled with a huge excess in demand at the regulated prices. The underpricing of domestic natural gas and the resulting nonprice rationing imposed by the gas distributions are direct causes of the recent contracts with Algeria and other foreign nations to import liquified gas (LNG) at prices at least triple those on existing domestic gas contracts. Professors James Cox and Arthur Wright of the University of Massachusetts earlier this year stated in testimony before the House Ways and Means Committee:

"The principal cause of the unseemly situation (the natural gas shortage) is wrongheaded price regulation by the Federal Power Commission which has controlled field contract prices of gas for interstate shipment since about 1960. The FPC has held field prices so low that gas companies have not found it profitable to develop and produce gas for interstate shipment from new domestic reserves. Regulatory agencies at the retail level have transmitted the FPC's underpricing to retail markets by basing rates on field prices plus pipeline charges. . . .

"The solution to both the present and future shortages advanced by both industry spokesmen and others not open to conflict of interest, is to deregulate the field price of gas. The major argument for deregulating, aside from doing away with exceedingly cumbersome bureaucratic machinery, is that, on the best available economic evidence, the field prices of natural gas were set by competitive forces before the FPC began fixing prices . . ." [1]

Since natural gas at the wellhead accounts for only 10–15 percent of the cost to the consumer, the price increases at the well head which can be expected from deregulating the price of a commodity in short supply would increase consumer prices modestly. In 1972, the average annual gas bill of the residential consumer amounted to $155.73. A recent study by Foster Associates estimated that with deregulation of gas prices, the cost would increase in the short term by $8.30 per year using a 55 cent field market-price assumption and by $10.03 at a 65 cent estimate. Over the period to 1980, the increase in residential consumer costs owing to rising field prices would be 2.8 or 3.4 percent per year at the 55 and 65 cent market price assumptions.[2] These price assumptions are consistent with the studies of MacAvoy and Pindyck referred to above.

Unless increased production is made more attractive—by lifting price controls or by direct subsidy—the alternative appears to involve running out of sufficient domestic gas to heat homes and relying on

[1] Paper presented to the House Committee on Ways & Means, reprinted in Part 9 of 11 parts "*General Tax Reform*", 1st Session 93rd Congress, pp. 1392–1492.

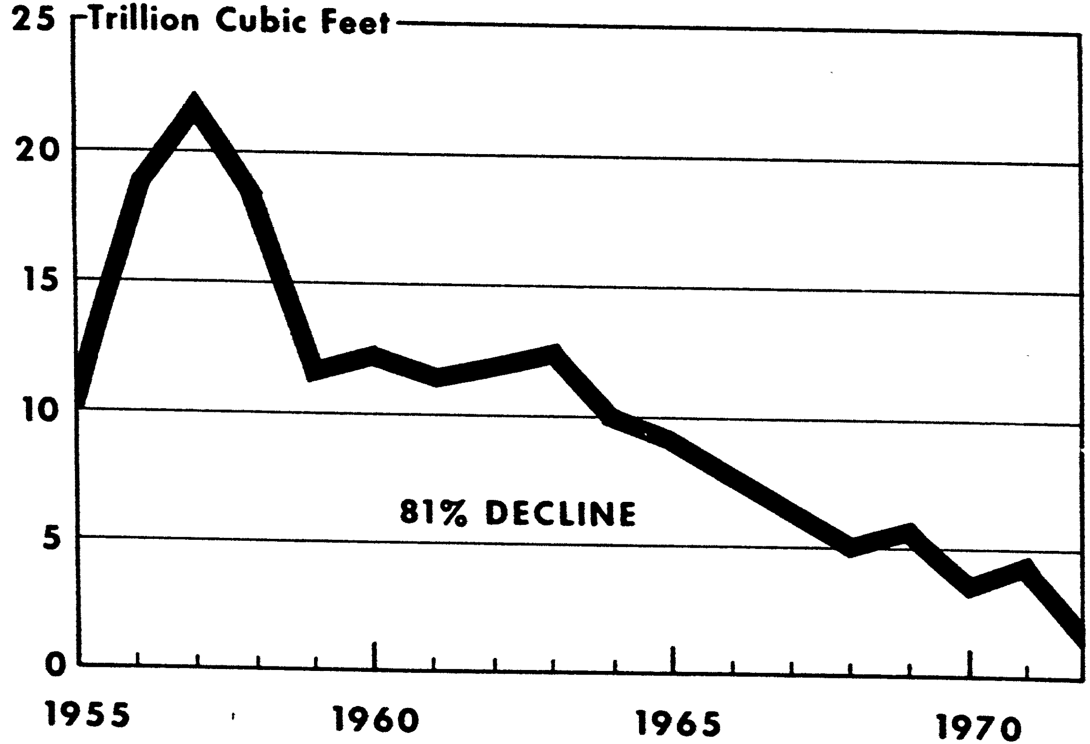
[2] See Foster Associates, Inc., ***The Impact of Deregulation on Natural Gas Prices***, **August 1973.**

Soviet or Algerian gas which, besides the risk of interruption, is triple the domestic prices and would still be higher than domestic prices even after deregulation.

The market price for any commodity must reflect the costs of production and distribution and a reasonable profit expectation. Recent experience with controls on the price of one product and no controls on all costs or market substitutes and the subsequent market distortions caused thereby should be enough evidence to question the wisdom of FPC pricing policies. As had been widely reported in the press last summer, controls over the price of chicken but not the cost of feed, led to the drowning of baby chickens. Similarly, controls over the price of gas but not the cost of producing it, prevents a lot of gas from being found.

NATURAL GAS FINDING RATE IN THE U. S.

EXCLUDES ALASKAN NORTH SLOPE



Source : Federal Power Commission.

19

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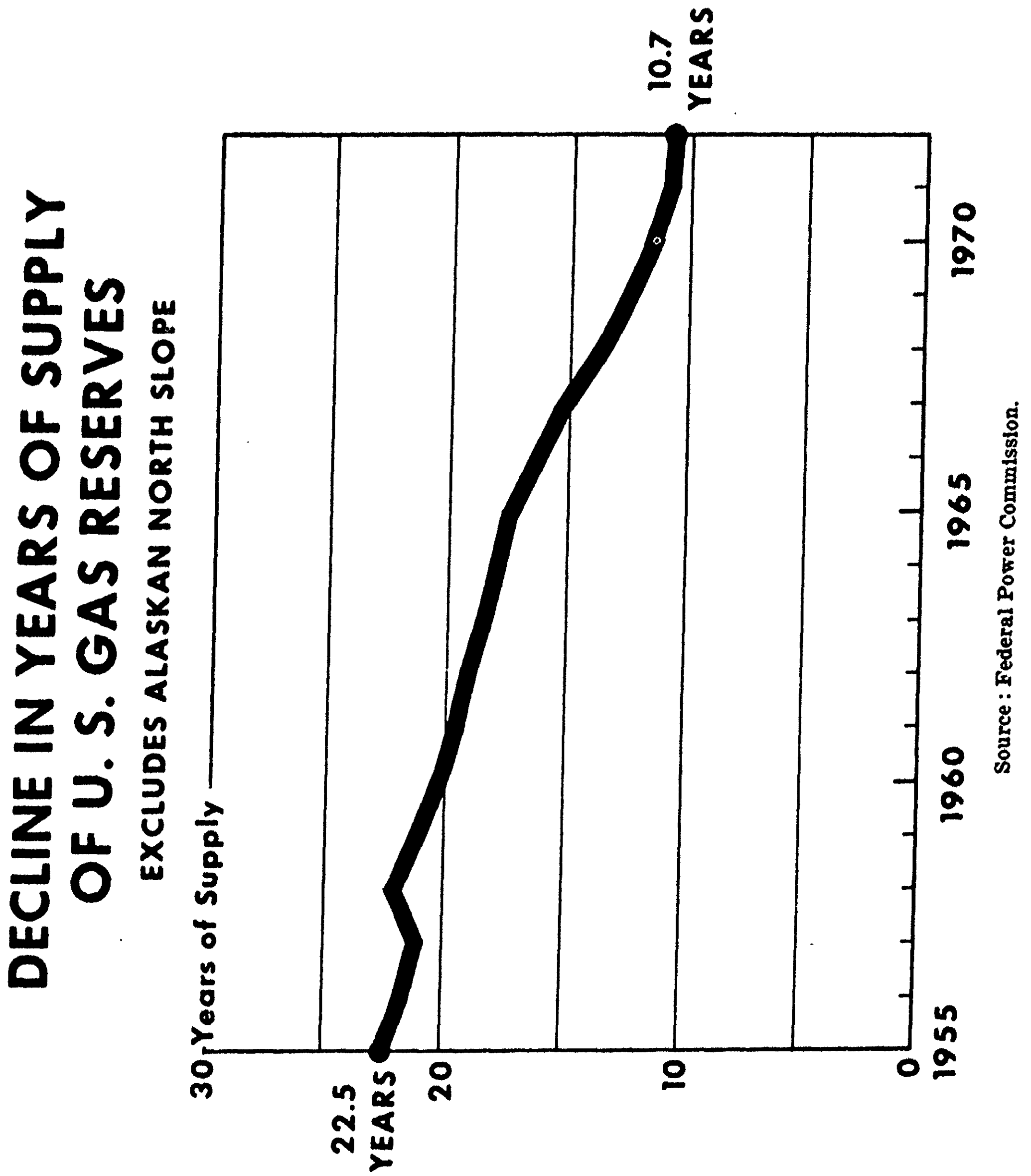

III. Implications of the Energy Shortage

THE NATIONAL ECONOMY

There is a direct correlation between energy consumption and economic growth. The importance of energy to our national economy was aptly stated by the Joint Economic Committee in a September, 1970 report, *Economy, Energy and the Environment:*

> "The economy of the United States and the technologically advanced nations is based on energy. Energy is the ultimate raw material which permits the continued recycle of resources into most of man's requirements for food, clothing and shelter. The productivity (and consumption) of society is directly related to the per capita energy available."

That energy consumption and economic growth go hand in hand is illustrated by the following chart:

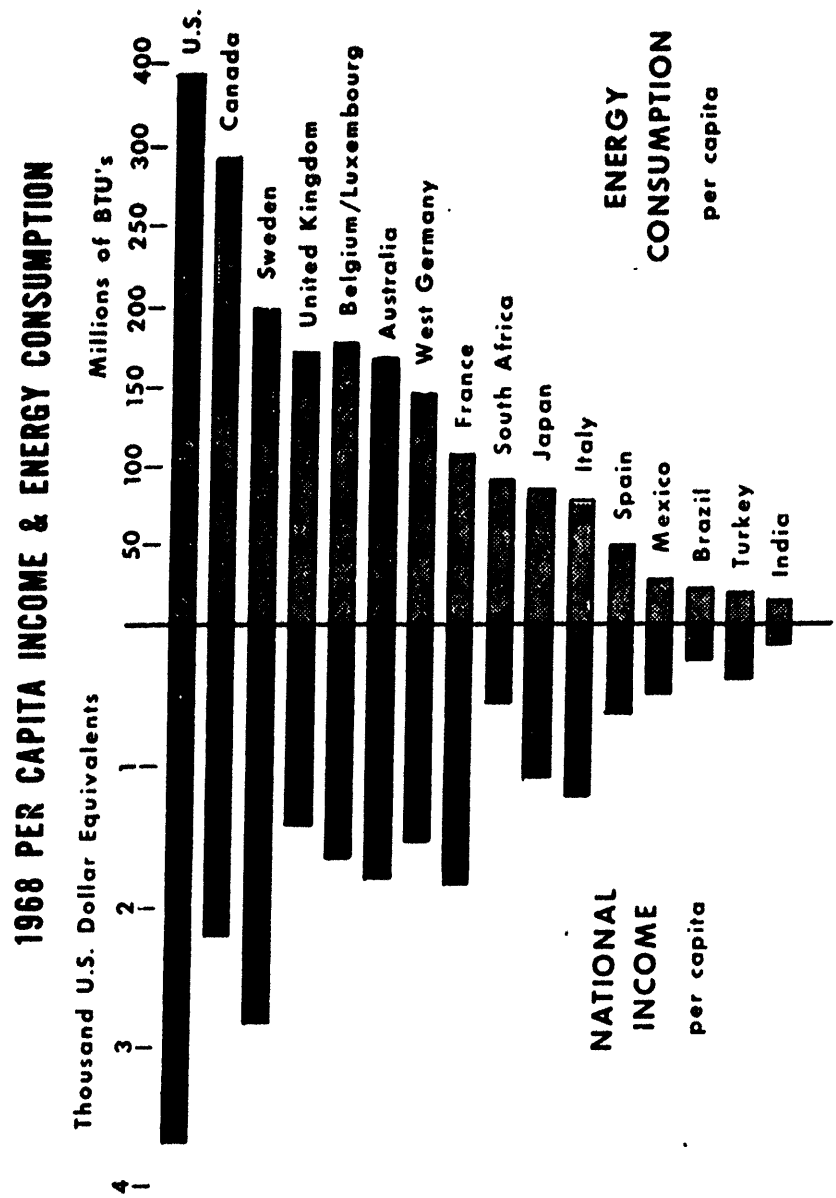

Figure 1

Source: U.S. Department of the Interior

The present shortage of available fossil fuels in the U.S. will have an immediate and direct impact on the productivity of the American economy. Many companies will not be able to maintain their current levels of output. Certain industries, such as the petro-chemical industry, are heavily dependent upon energy imports for use as feed stocks. Other sectors of the economy, such as the agricultural and fertilizer industries, similarly use energy resources not only as a fuel but also as a component of production. Thus, the energy shortage not only affects the use of energy as a fuel, in transportation, housing and industry, but also the capacity of farms and factories to continue production. The Executive has already established an industry priority list to allocate fuels according to the assumed importance of each industry to the national economy.

A primary cause of current inflation is the shortage of agricultural and other raw materials. The energy shortage will exacerbate inflationary pressures in the economy, and perhaps eventually lead to a recession. The chain of events may be simply illustrated as follows:

$$\text{Energy Shortage} \longrightarrow \text{Decline in Fuel Consumption} \longrightarrow \text{Reduced Output} \begin{cases} \nearrow \text{Unemployment} \\ \searrow \text{Inflation} \end{cases}$$

In short, the current energy shortage (as well as decisions to restrain the consumption of energy) has important implications for the economy, including prices, productivity, employment and growth.

Because the energy shortage so directly affects the national economy, it also affects national goals and commitments. The energy shortage, for example, could seriously impair the country's ability to achieve full employment, or meet housing needs, or to bring about clean air. With our Defense establishment 50 percent dependent on foreign sources for its fuel consumption, there are security implications of a prolonged energy shortage. The Defense Department's fiscal 1974 projection of fuel consumption was 670,000 barrels per day. On November 1, 1973 the President invoked the Defense Production Act to give the Department of Defense first priority over U.S. production.

Environmental concerns offer a good example of a competing, if not conflicting, national priority which will be adversely affected by the shortage of energy and the resort to less desirable fuels. An important aim of this subcommittee is to determine how fiscal policies can be employed to reconcile these apparently conflicting national goals.

THE BALANCE OF PAYMENTS

There is a great deal of uncertainty with respect to the impact of energy requirements on the U.S. balance of payments. Nobody really knows what the price of imported oil and gas will be by 1980 or 1985, or even what U.S. demand will be. The situation is so volatile that long term projections are of questionable validity.

The Commerce Department has devised a model[1] which assumes crude oil price increases from $2.33 per barrel in 1970 to $10.00 per barrel in 1985. As a result of both price increases and import

[1] The Commerce Department model is presented in Appendix C.

demands it is projected that the import bill on a c.i.f. basis would be approximately $40 billion in 1985. These price assumptions seem unrealistic as imported oil is currently going for $9 to $12 a barrel. The Department's model, further, assumes that U.S. exports to oil producers will increase from $1.9 billion in 1970 to $21 billion in 1985 and that the capital inflows from oil producing nations will increase from $0.3 billion to $11.8 billion over this period. As a result, the Commerce Department's model shows the basic balance of payments deficit resulting from oil imports to hit a peak to $12 billion in 1980 and tail off into a surplus by 1985. The projections are highly speculative and several underlying assumptions are questionable. Because of recent price increases the Department changed its 1980 forecast deficit from $3.1 billion to $12 billion.

A large part of the assumed future credits to the U.S. balance of payments labeled as producing company profits or repatriated income may not materialize if U.S. holdings are nationalized, as is already happening in Arab nations. Tanker rates are assumed in one model to be static which seems unrealistic in the light of higher prices, insurance, and wage cost increases generally.

Given the long run imponderables, it may be more reasonable to analyze only the shorter term impact of oil on the balance of payments. Even here the assumptions with regard to price and availability are risky. For example, the volume of imports has risen by more than 50% between 1971 and 1973, while the value of imports has increased by more than 100%. The basic price for foreign oil is generally assumed to be the Persian Gulf f.o.b. price of Arabian crude oil. Since the signing of the Teheran Agreement in February 1971 which brought about a 30% increase in the per barrel revenue of Middle East producing countries, the cost of Saudi Arabian light crude has developed as follows:

TABLE 6.—*Saudi Arabian Posted Prices, Government Revenues and Market Prices, February 1971–October 1973*

	February 1971	Oct. 1, 1973	Oct. 16, 1973
Arabian light 34°:			
Posting	$2.18	$3.01	$5.12
Government take	1.27	1.77	3.05
Market price f.o.b.	[1] 1.70	[1] 2.08	3.67

[1] Reported spot price.

Source: Paper presented by John H. Lichtblau, Executive Director, Petroleum Industry Research Foundation, Inc. to Joint Economic Committee on November 7, 1973.

By far the largest of the several price increases occurred on October 16 of this year when governmental revenue in one single step was raised by 70%. With the current Middle East situation still unsettled the producing nations may increase their prices even greater while cutting back on production, and, when the producing spigot is turned on again, hopefully in the near future, the prices are likely to remain at an extremely high level because the demand for Middle East oil is so great. Japan and Europe are almost totally dependent on Middle East oil.

As a result, oil imports which are currently costing in balance of payments terms about $7 billion may double or triple by 1975.

Perhaps the most important issue is not how much we will pay for imported oil but whether or not we will be able to get it at all. Oil in the ground may well be more valuable to Arab producing countries both in economic and political terms than oil exported to the United States and other countries. If the vast reserves of the Middle East are not produced, the world economy faces very serious problems. The last Middle East war led to a sharp cutback in oil production by the Middle East producers. As a result, Western Europe and Japan—to a greater degree than the United States—are facing very serious shortages. In those countries, the choice may not be whether to heat the home at 68 or 72 degrees, or paying 10 cents or 20 cents more for a gallon of gasoline, but between heating a home or running a factory or having a job or running a school.

IV. Fiscal Policy and the Energy Problem

While other Committees of Congress have conducted intensive and lengthy hearings on various aspects of the energy problem, the Finance Committee's jurisdiction over fiscal policies makes it logical for it to look into the fiscal ramifications of the energy problem. The key questions were raised at the outset of this document.

FISCAL INCENTIVES ON THE SUPPLY SIDE

Fiscal incentives have been recommended to increase the domestic supply of fossil fuels (and to develop alternatives) and thereby reduce the dependency on insecure foreign sources of supply as well as lessen the balance of payments drain of imported fuel. The proposals advanced include:

(*a*) Domestic exploratory drilling investment credit and supplementary investment credit for commercially productive wells.

(*b*) Investment credit for research and development aimed at the commercial exploitation of solar energy, geothermal energy, oil from shale and tar sands, gasification or liquefaction of coal, advanced power cycles and other non-nuclear energy sources.

(*c*) Investment credit for desulfurization equipment and conversion to coal.

Domestic Exploratory Drilling Investment Credit

Domestic exploratory drilling for oil and gas has declined since 1966 both because of the increased cost of domestic drilling (up 133% per well over the past decade) and because of the often greater promise of overseas drilling prospects. Price controls may also have served to discourage domestic drilling.

To encourage the development of new oil and gas production, the Administration has proposed a two-stage investment tax credit:

(*a*) a 7% credit on the costs of exploration for new wells, and

(*b*) an additional 5% credit for successful drilling of new wells.

The Administration's tax credit is tied to new field exploratory drilling conducted anywhere within the 50 States, on the continental shelf surrounding the U.S., or within Puerto Rico or territories or possessions of the U.S. or their surrounding waters.

S. 1295 (introduced by Senators Tower, Hansen and Stevens) would provide a 12½% tax credit for expenditures made for exploration and development of new reserves of oil and gas in the U.S., regardless of the commercial success of the exploratory drilling.

Financing Mandatory Conversions From Petroleum to Coal

The President has called for conversion of certain electric power plants, which now burn petroleum or natural gas, to coal. Section 204(a) of S. 2589, the National Energy Emergency Act of 1973, would require such conversions.

Obviously there will be some financial burden on the owners of such power plants. These may be passed on to the customers or shareholders of the companies that incur the costs. On the other hand the benefits of the conversion will probably flow to the entire population of the United States rather than solely to the customers of the companies.

Therefore, Chairman Nassikas of the Federal Power Commission suggests that some consideration may be given to a special credit for costs arising out of the initial conversion and subsequent reconversion of power plants.

ESTABLISHMENT OF AN ENERGY TRUST FUND

Paramount in the effort to come to grips with the energy crisis over the long term is the need to marshal this country's technology and capital resources in a national commitment to research and develop alternative sources of energy. A national effort of the intensity and duration of the Manhattan Project of World War II or the space program of the 1960's could lead to the full utilization of this country's vast fossil fuel resource as well as the development of new energy systems. An energy trust fund would assure that a national energy program would be adequately and consistently funded. Such a trust fund might be supported by the imposition of a tax based upon Btu's of energy, represented in sales of crude oil, petroleum products, natural gas and coal by a producer or importer. Such a tax could be set at different rates for each of the years in which varying levels of funding are necessary or it could be set at a minimum rate providing for a gradual accumulation of funds to meet the anticipated expenditure needs over the life of the trust fund.

S. 2167 (introduced by Senators Cook, Baker and R. Byrd) provides for the establishment of a Federal Energy Research and Development Trust Fund which would be supported by the transfer of revenues payable to the United States under the Outer Continental Shelf Lands Act annually, plus any general revenues necessary to provide $2 billion per year for energy research and development. It appears that this bill may have been introduced to insure funding for the research called for by S. 1283 (introduced by Senator Jackson and others) which calls for a ten-year, $20 billion program to finance non-nuclear energy research and development in the areas of coal gasification, coal liquefaction, advanced power cycles, shale oil and geothermal power. The program would be coordinated through a general manager for non-nuclear research and development at the Atomic Energy Commission and would be carried out through three quasi-public corporations for coal gasification, coal liquefaction and advanced power cycles. Research and development on oil shale extraction, geothermal power, solar, wind, nuclear fusion and other forms of energy would be undertaken by private companies directly subsidized for their research and development expenses or compensated through firm purchase commitments for specific amounts of energy produced. The Administration has indicated support for a $20 billion program for research and development over 10 years and has already committed $1 billion for energy research and development for fiscal year 1974. A summary of that research and development spending plan for fiscal year 1974, is shown below. Over half of the money in fiscal 1974 is committed to nuclear fission. It is not at all clear that this is the safest investment. The breeder reactor has radioactive fallout, the disposal of which has not been solved. Solar energy may be a better long term answer to our energy problems. At any rate, a team of scientists, engineers and economists may be needed to evaluate critically the government's research and development program, showing clearly the costs and benefits of the various alternatives. Appendix E gives a survey of Federal research and development efforts over the past five years.

TABLE 7.—*Energy Research and Development Program Spending*

[In millions of dollars]

	Additional increment [1]	Total, fiscal 1974
Coal	49.5	168.0
Geothermal	7.0	11.1
Environmental control	12.0	58.5
Energy conversion (including solar)	5.0	25.2
Conservation	6.3	15.5
Gas-cooled nuclear reactors	7.1	16.2
Automotive energy R. & D.	6.0	22.7
Environmental effects	5.4	43.9
Electric transmission, distribution	3.2	8.0
Nuclear fusion (magnetic confinement)	7.3	54.8
Miscellaneous program increases	6.2	20.5
Energy R. & D. programs not receiving program increase:		
(a) Other nuclear fission programs	0	503.5
(b) Laser fusion	0	42.9
(c) Other	0	4.4
Total	115.0	995.2

[1] Monies requested by the President in November 1973 in addition to the amounts in the original 1974 budget submitted in January 1973.

Source: Office of Management and Budget.

FISCAL DISINCENTIVES ON THE DEMAND SIDE

It appears that the short term energy problem may require a rationing and allocation system (the latter is already in existence). Some have suggested taxing consumption of gasoline, or automobiles based on their gas mileage, or both, as a policy necessary to discourage consumption.

Federal Excise Tax on Gasoline

It has been suggested by Dr. Herbert Stein, chairman of the Council of Economic Advisers that an excise tax on gasoline might be imposed. The effect of such a tax would be to curtail demand. One estimate provided to the staff indicates an excise tax which doubles the cost of gasoline to the consumer could be expected to curtail current demand by 70%.

This assumes, however, that alternative means of transportation exist to get to work and necessary shopping, for desired shifts in driving habits could not be achieved due to the absence of viable transportation alternatives. Accordingly, a national commitment to urban transit systems appears to be an important aspect of the energy problem.

Federal Excise Tax on New Automobiles Based Upon Their Fuel Consumption Rate

Three bills currently pending in the Senate (S. 2036, introduced by Senator Moss; S. 2428, introduced by Senator Percy; and S. 2595, introduced by Senator Dominick) would impose a tax to serve as an incentive for production of automobiles capable of greater fuel economy. Essentially these bills would impose a progressively higher excise tax on all new vehicles manufactured which obtain less than a rate of 20 miles per gallon of gasoline. As the efficiency of the vehicle declines, the amount of tax is scheduled to increase.

Repeal of Tax Provisions Which Now Indirectly Result in Subsidizing Consumer Prices of Petroleum Products

Dr. Irwin M. Stelzer, in testimony before the Committee on Interior and Insular Affairs, has asserted that tax subsidies have distorted the price structure of our energy supplies and have resulted in price maintenance at uneconomically low levels. Consumers, he argues, have been provided with price signals which fail to reflect the full cost of petroleum products, and have tended to use uneconomically large amounts of gasoline and other related products. It is suggested that any reduction of net return on investment as a result of the repeal of these tax provisions should be recouped through an increase in the price of crude oil which would correct this temporary disequilibrium.

However, in testimony before the House Ways and Means Committee, representatives appearing on behalf of the American Petroleum Institute countered that price elasticity has not kept pace with increasing industry costs and current investment yields from new exploration and development activities are actually lower than returns now being obtained on corporate bonds or long-term certificates of deposit. Therefore, to continue to attract new risk capital they urged that the petroleum industry must be provided with increased tax incentives to stimulate greater domestic exploration and development activity, expanded storage facilities and domestic refinery expansion. In addition, they contended that in the international arena, any changes in the U.S. Federal tax structure would severely hamper American petroleum companies competing in the world oil market and would ultimately result in U.S. dependence on foreign governments for essential foreign oil supplies. They also noted that U.S. petroleum companies operating abroad under the present tax structure are making an important contribution to our balance of payment situation. In 1971, they stated, these companies' remitted earnings exceeded new outlays by approximately $1.5 billion.

The tax incentive approach is aimed at increasing the supply while holding down prices. Such incentives tend to encourage consumption and profitability, thus attracting capital to the industry and benefiting the consumer. The market approach would tend to increase the supply through price increases, hold down consumption and perhaps be less of an incentive to invest in the industry although this latter effect is questionable.

A summary of the principal provisions of the Internal Revenue Code affecting energy resources, production, and consumption is provided in Appendix B.

V. U.S. Trade Policy and the Energy Problem

The United States first became a net importer of petroleum in 1948. Between 1960 and 1970, US oil imports hovered around 20% of consumption, with most of these imports coming from Venezuela and Canada. Up until the mid-1960s the United States had excess domestic production capacity nearly equal to imports. As late as the Arab-Israeli war of 1967, the United States still had some excess production capacity. This was no longer true by March 1972, when Texas and Louisiana removed all production controls. Crude oil production decreased slightly between 1970 and 1972, and we are now producing at full capacity with almost no domestic cushion for emergencies.

No sizable domestic production increase is expected until Alaskan oil from the North Slope reaches the market—by 1977 at the earliest. Alaskan production of about two million bpd will do little more than compensate for declining output in the "lower 48" states by 1980.

By the end of the decade, if present energy policies were continued, as much as half of the oil consumed in the United States would have to be imported—about 11 million bpd out of a total of some 22 million bpd needed. Canada, Venezuela, and other Western Hemisphere sources would probably furnish about four million bpd. The rest would come from the Eastern Hemisphere.

Beginning in 1955, the United States controlled oil imports on national security grounds. At first such controls were on a voluntary basis, but on March 10, 1959, the country adopted a mandatory oil import program.

That program was changed frequently during its lifetime with a growing number of special exemptions granted for one reason or another. With rapid changes in the domestic and international world oil situation, the mandatory quota controls began to unravel during the late 1960's and were officially abandoned this past May.

The history of the mandatory oil import program (MOIP) from its inception on March 10, 1959, through its demise on May 1, 1973 is provided in Appendix F.

The Mandatory Oil Import Program has been the subject of considerable controversy over the years. Whatever its weaknesses and defects were, it is useful to ask the question: Where would we be today in terms of domestic productive capacity and the labor and technology needed to exploit our fossil fuel resources if we had no import re-restraints and if imports now constituted the same portion of our domestic consumption as they do in Europe and Japan?

A further question that should be analyzed is: Given the ability of the major oil-producing nations to price their product at whatever the market will bear, how can we encourage the investment in our own resources of energy, which admittedly will cost more per barrel than those in the Middle East, unless we have a flexible import policy which would prevent foreign producers from undercutting our own investment by sharply reducing their own selling prices?

At present the Arab nations can charge $9–12 a barrel because our existing productive capacities are insufficient to supply our own needs. But if we bring on new production, which may involve costs of $5–$7 a barrel, and the Arab nations then drop the price to $4 a barrel, where will the American producer stand? Given these facts, do we need a flexible tariff instrument to assure U.S. investors in the domestic petroleum market that it would be worthwhile making the investment? The estimated costs of production, shown in the table below, indicate the degree of price flexibility the oil producing nations have.

TABLE 8.—*Estimated cost of production of representative crude oils exported to the United States, f.o.b. port of export, July 1972*

[In U.S. dollars per barrel]

Country	Average real extraction cost	Royalty	Tax	Average total cost
Saudi Arabia	$0.130	$0.310	$1.121	$1.561
Iran	.130	.308	1.116	1.554
Nigeria	.380	.426	1.432	[1] 2.258
Venezuela	.400	.608	1.307	2.315
Libya	.450	.453	1.494	[2] 2.495
Algeria	.750	.473	1.410	2.633
United States [3]	1.080	.370	.770	2.220

[1] Includes harbor dues of $0.020 per barrel.
[2] Includes retroactive buy-out of $0.098 per barrel.
[3] Average data for a west Texas, 4,000-foot well, with an initial production rate of 50 barrels per day and a 15-percent production decline rate. Exploration costs are not included.

Source: Foreign data compiled from statistics of the Office of Oil and Gas, U.S. Department of the Interior. U.S. data based on Bureau of Mines *Information Circular* 8561, 1972.

The current direct and indirect restrictions on the importation and exportation of energy resources are provided below. This information was supplied, upon request, by the General Counsel's office of the Tariff Commission.

REGULATIONS AND RESTRICTIONS ON THE IMPORTATION OF ENERGY RESOURCES

Direct Restrictions

Petroleum

The Mandatory Oil Import Program of quantitative restrictions on the importation of crude oil, unfinished oils and petroleum products was replaced by Presidential Proclamation 4210 of April 18, 1973, which instituted a system of license fees. The new control program is administered by the Office of Oil and Gas in the Department of the Interior, which promulgates oil import regulations.

Anyone in the 50 States and Puerto Rico can obtain a license to import any quantity of crude oil, unfinished oils or petroleum products upon payment of the appropriate fee, as set forth below.

Basic fee schedule (Proc. 4210, sec. 3(a))

[In cents per barrel]

	May 1, 1973	Nov. 1, 1973	May 1, 1974	Nov. 1, 1974	May 1, 1975	Nov. 1, 1975
Crude	10.5	13.0	15.5	13.0	21.0	21.0
Motor gasoline	52.0	54.5	57.0	59.5	63.0	63.0
All other finished products and unfinished oils (except ethane, propane, butanes, and asphalt)	15.0	20.0	30.0	42.0	52.0	63.0

Preferential fee schedule for Canadian imports (Proc. 4227, sec. 3(a)(ii))

[Cents per barrel]

	May 1, 1973	Nov. 1, 1973	May 1, 1974	Nov. 1, 1974	May 1, 1975	Nov. 1, 1975	May 1, 1976	Nov. 1, 1976
Motor gasoline	0	0	5.7	6.0	12.6	12.6	22.1	22.1
Other finished products (but not including ethane, propane, butanes, or asphalt)	0	0	3.0	4.2	10.4	12.6	22.1	22.1

	May 1, 1977	Nov. 1, 1977	May 1, 1978	Nov. 1, 1978	May 1, 1979	Nov. 1, 1979	May 1, 1980	Nov. 1, 1980
Motor gasoline	31.5	31.5	41.0	41.0	50.4	50.4	63.0	63.0
Other finished products (but not including ethane, propane, butanes, or asphalt)	31.5	31.5	41.0	41.0	50.4	50.4	63.0	63.0

Section 16 of the Presidential Proclamation 4210 temporarily suspends the duties on the products in Schedule 4, Part 10 of the Tariff Schedules of the United States (TSUS). Proclamation 4210 also establishes certain fee-free allowances, which decrease annually until 1980 when they are to be eliminated. Presidential Proclamation 4227 of June 19, 1973, amended Proclamation 4210 by providing a preference for imports from Canada.

The Oil Import Appeals Board is empowered to grant variances in the fee-control system. It can correct errors in allocations, grant modifications in allocations on the ground of exceptional hardships or special circumstances, and review the revocation or suspension of any allocation or license.

The subject of imports of petroleum and products thereof is treated more fully in the Tariff Commission's report of October 1973 to the Committee on Finance of the Senate.

NATURAL GAS

Under item 475.15 of the Tariff Schedules of the United States (TSUS), natural gas is free of import duty. Such imports arrive from contiguous countries by pipeline and from other countries in liquefied form (LNG).

Under the National Gas Act, a license of the Federal Power Commission is required before natural gas can be imported (15 U.S.C. 717b). Under the Power Commission's regulations an application for a license to import must contain the appropriate fee as prescribed in 18 C.F.R. 159, as well as a statement of the reasons why the proposed importation of natural gas will not be inconsistent with the public interest and will not in any way impair the ability of the applicant to render natural-gas service at reasonable rates to U.S. customers. In making its determination, the Commission considers the economic and technical feasibility of facilities, foreign-policy matters (in consultation with the Department of State), security aspects (in consultation with the Defense Department), environmental factors, and cost of the material to be imported.

ATOMIC ENERGY

Under the Atomic Energy Act of 1954, the Atomic Energy Commission is authorized to issue licenses for the importation and any utilization or production facilities for atomic energy (42 U.S.C. 2121). AEC Regulations establish procedures and criteria for the issuance of licenses to import source material (uranium or thorium) into the United States. A Type 103 license is required for commercial and industrial facilities, and the appropriate fees are set out in 10 C.F.R. 1703. Unimportant quantities of source material are exempted from the license requirement.

Ores of thorium (item 601.45) and uranium (item 601.57) are duty-free under the TSUS, as are radioactive chemical elements, isotopes, and compounds (item 494.50).

Coal

The domestic abundance of coal and its high cost of shipping demonstrate no need for import restrictions on coal. Coal of all classifications, under item 521.31 of the TSUS, is duty-free.

Other Energy Forms

Methyl alcohol.—Methyl alcohol has become a matter of interest as a source of energy. This product is presently dutiable under item 427.96 of the TSUS at the rate of 7.6 cents per gallon (column 1) and 18 cents per gallon (column 2). Even though methyl alcohol costs more to produce than liquefied natural gas (LNG), it does not require expensive, specialized tankers for shipment as does LNG. To increase the cost competitiveness of methyl alcohol as a fuel, it has been proposed by some U.S. gas producers that methyl alcohol used to generate energy—either through actual burning of the methyl alcohol or reforming of the methyl alcohol into gas which is then burned—be accorded duty-free status.

Synthetic (or substitute) natural gas (SNG).—This fuel—which to date has not been imported and, as far as can be foreseen, probably never will be imported—results from the gasification of light liquid hydrocarbons, such as naphtha. Under the current oil import program (Pres. Procs. 4210, 4227), naphtha to be used in making SNG is subject to the appropriate license fee, unless the producer holds a fee-free allocation. Proclamation 4210 suspended the duties imposed on naphtha under item 475.35 of the TSUS. It should be noted that once SNG enters an interstate pipeline and becomes mixed with natural gas, it becomes subject to the jurisdiction of the Federal Power Commission.

Indirect Restrictions

Federal

There are restrictions which exert an indirect impact on energy imports. While these indirect restrictions may be less visible than those of a direct nature, they nonetheless also limit what may be imported in the way of energy resources. Environmental concerns delaying the Trans-Alaska Oil and Gas Pipeline, offshore drilling, and sale of Federal lands for exploration of oil and gas have necessitated increased imports. Similar environmental concerns have made it difficult to site refineries and nuclear plants, the former resulting in increased petroleum product imports and the latter causing increased requirements for other fuels.

Control of domestic natural gas prices at an artificially low level has affected the availability of natural gas, resulting, to some extent, in the need for increased imports of oil and of LNG. Cost of Living Council controls on what part of a cost increase can be passed on to the consumer may discourage some importation.

Tax laws also influence imports, as do natural security aspects of the sources of the imports. The Jones Act adds 8 to 10 cents per mcf to the cost of transporting LNG between Alaska and the west coast by American flag vessels as compared to foreign flag vessels. This increased cost could divert LNG from Alaska to other countries, while making it less expensive to import LNG from the South Pacific or Russia to the United States.

Further effects on imports may result from failure to construct superports for handling the economically advantageous very large crude carriers (VLCC's); environmental concerns or jurisdictional disagreement over who is to license and determine where they are to be built are factors in this area. Proposed legislation to require 20 percent of U.S. oil imports to be carried on U.S. flag vessels initially and 30 percent by 1977 would also affect imports.

State and Local

While most of the above restrictions are Federal in nature, some also involve States' rights with an indirect impact on the importation of energy. These include local harbor rules, such as berthing procedures, pilot tugs employment, and local union provisions, safety precautions, and environmental concerns. In this latter area States have been particularly active issuing rules on allowable water and air pollution including the admissible sulfur levels in fuel. In some instances the State rules on air pollution are more restrictive than the Federal and often differ within the State, depending upon the condition of the ambient air and the fuel. In Massachusetts, for example, State standards now limit sulfur content to 0.3 percent in home-heating oil, 0.5 percent in residual fuel oil burned in Boston and some 12 other communities, and 1.0 percent for residual fuel oil burned elsewhere in Massachusetts. New York City, after an LNG tank explosion on Staten Island, imposed a ban on new construction of all tanks over 52,000 gallons capacity until the investigation of the disaster has been completed. Any additional safety measures resulting from the investigation will have to be implemented on all tanks under construction.

There are many other areas where State and other local practices impact indirectly on imports of energy resources. We have not delved into these practices to any extent; in no way is it to be construed that this note exhaustively covers all things impacting energy resource imports either directly or indirectly. Only a thorough study of local and State laws and other practices would uncover all restrictions.

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REGULATIONS AND RESTRICTIONS ON THE EXPORTATION OF ENERGY RESOURCES

General

The Export Administration Act of December 30, 1969, 50 App. U.S.C. §§ 2401 et. seq., is the starting point for an analysis of the statutory provisions regulating exports. Two of the United States export policies, for purposes of this Act, are to use export controls "to the extent necessary to protect the domestic economy from the excessive drain of source materials and to reduce the serious inflationary impact of abnormal foreign demand. . . ." and to promote the national security (50 App. U.S.C. § 2402). The authority to effectuate this policy through institutional organization is given to the Secretary of Commerce (50 App. U.S.C. § 2403) and administered by the Office of Export Control. The President is given the authority to prohibit or curtail exportation by issuing rules or regulations, and these rules and regulations "may apply to the financing, transporting, and other servicing of exports. . . ."

15 C.F.R. contains the regulations issued by the Commerce Department for the administration of the Export Administration Act. The Department of Commerce has licensing jurisdiction over all items on its Commodity Control Lists (CCL), which includes petroleum, petroleum products, and coal. The fact that a commodity is on the CCL does not necessarily mean that Commerce will require a license. Part 370 sets out the general export licensing policy. According to 15 C.F.R. 373.5, certain commodities, including petroleum products, are subject to a periodic requirements license if they may be exported for a period of one year from issuance of the license to one or more ultimate consignees in a single country of destination.[1] Part 377 sets out the commodities subject to short supply quota control by the Department of Commerce. At the present time, fossil fuel exports are not so controlled.[2] Fossil fuels are not currently under consideration at the Commerce Department for inclusion in the short supply category.

Executive Order No. 11533 of June 4, 1970 (35 F.R. 8799), provides for the administration of the Export Administration Act. Section 1 delegates Presidential power under the Act to the Secretary of Commerce; section 2 reestablishes the Export Control Review Board of Executive Order No. 10945 of May 24, 1961, as the Export Administration Review Board; section 3 states under what circumstances the Secretary of Commerce may and must refer export license matters to

[1] However, at the present time only petroleum exports to South Rhodesia, Cuba, North Vietnam, and North Korea require licenses.

[2] Licenses on a worldwide basis are required for eight highly specialized fossil fuel products with national security implications. This list does not include consumer-type products. Exports of these specialized products are but a very small part of the total exports of petroleum products.

the Export Administration Review Board; section 4 gives the President authority to prescribe rules and regulations applicable to section 1.

Although most energy resources could be considered to be in short supply under the Export Administration Act, there is some question as to whether abnormal foreign demand is causing an inflation impact with respect to any particular energy resource. As indicated above, both criteria must be met before export controls may be applied under this Act. However, the Senate Committee on Banking, Housing and Urban Affairs is currently considering legislation, already passed by the House (H.R. 8547), which would amend the Export Administration Act so as to authorize the President to impose export controls during conditions (i) of scarce supply *or* (ii) serious inflation caused by abnormal foreign demand. If passed, the President would have clear authority to regulate the export of any energy resource which was in scarce supply.

The *Defense Production Act of 1950,* as amended, provides the President with broad authority to allocate and control the distribution of any materials in the civilian market if he determines that:

1. such materials are scarce and critical to the national defense, and
2. the national defense requirements for such material cannot otherwise be met without significant dislocation of the civilian market.

On November 1, the President invoked the Defense Production Act to give the U.S. Defense Department absolute priority on U.S. production.

The Defense Department traditionally depends on foreign sources for about 50 percent of its needs. The department projected its fiscal year 1974 consumption to be about 670,000 barrels per day. About half of the consumption is for U.S. use; the rest is consumed abroad by the offshore fleets. The sixth and seventh fleet had depended almost entirely on foreign oil. With the Arab oil embargo, they will have to depend on U.S. sources.

Thus, the priority allocation will preempt about 335,000 barrels a day for Defense purposes that would ordinarily be used in the civilian economy.

Although this act does not provide specific authority to regulate exports, it could conceivably be used by the President to give domestic contracts priority over contracts for foreign delivery in cases where the national defense requirements were met. This could have a significant impact on the export of energy resources, especially with respect to coal where 10 percent of present production is under contract for foreign sale.

Pursuant to Executive Order No. 11423 of August 16, 1968 (33 F.R. 11741), authority over control of certain energy transporting facilities constructed and maintained on U.S. borders was granted to the Secretary of State. Section 1(a) of that order reads:

> Except with respect to facilities covered by Executive Orders No. 10485 and No. 10530, the Secretary of State is hereby designated and empowered to receive all applications for permits for the construction, connection, operation, or maintenance, at the borders of the United States, of: (i) pipelines, conveyor belts, and similar facilities for the exportation or importation of petroleum, petroleum products, coal, minerals, or other products to or from a foreign country. . . .

The Secretary of State is to request the views of appropriate department and agency heads and state and local government officials.

> Note that section 3 of the order asserts that the authority of the Secretary of State hereunder is supplemental, to, and does not supersede, existing authorities or delegation relating to importation, exportation, transmission, or transportation to or from a foreign country.

The Executive order concerns only border facilities and only indirectly affects Commerce's licensing of exports. To date there have been no regulations promulgated under this Executive order.

There are other indirect general export controls, many of the same type as affect import controls. Included in these are Federal and local environmental restrictions, labor laws.

Petroleum

The only legislation which specifically restricts the export of petroleum products was included in the so-called "Alaskan pipeline bill" (S. 1081), which was just enacted by Congress. The bill amends section 28(u) of the Mineral Leasing Act of 1920, as amended, so as to restrict the export of domestically produced crude oil transported by pipeline over public lands. Exports of crude oil transported under these conditions can only be made if the President determines that such exports "will not diminish the total quantity . . . of petroleum available to the United States," are in the national interest and are in accord with the provisions of the Export Administration Act of 1969. Any such determination could be overruled by concurrent resolution of Congress within 60 days of receipt of the determination from the President. This provision would currently apply primarily to petroleum exports to Canada and Mexico shipped by pipeline over public lands. However, the main object of this provision will be the future crude oil brought in from the Alaskan north shore.

The Office of Oil and Gas of the Department of the Interior allocates imports of crude and unfinished oils pursuant to section 9A (allocations based on exports of petrochemicals) of the oil import regulations.

These regulations provide for the allocation of imports of such oils into PAD districts I–IV and district V to persons operating petrochemical plants based on quantities of eligible petrochemicals which those persons manufacture and export. The eligible petrochemicals are listed in section 9A according to the trade classification schedule B number. Complex products are excluded from the list because of the difficulty in assigning allocations.

On October 26, 1973, the Department of Interior issued a regulation (38 F.R. 30572) pursuant to the Defense Production Act (see section A.) which authorizes the Director of the Office of Oil and Gas to issue directives to suppliers during any period of disruption in the military supply of petroleum products. The directives would require the suppliers to supply the required products to the Department of Defense regardless of other existing contracts.

On April 30, 1973 the Economic Stabilization Act of 1970 was amended by P.L. 93–28 to provide the President with authority (this authority has been delegated to the Office of Energy Policy) to allocate supplies of petroleum products in order to meet the essential needs of various sections of the Nation and to prevent anticompetitive effects resulting from shortages of such products. Although the amendment is not specifically concerned with export controls, the new authority could be used to guarantee that the major portion of domestic petroleum production be utilized for domestic consumption. In its report on the recent amending legislation, the Senate Committee on Banking, Housing and Urban Affairs indicated that it:

> . . . recognized the necessity of providing legislative authority to the President to assure that sufficient supplies of petroleum products be made available to consumers this year . . . (S. Report No. 93–63, p. 2).

Control of the prices at which crude oil and petroleum products may be sold domestically adds an incentive to export these materials when a higher price can be realized overseas. This situation exists at present due to a tight worldwide energy supply-demand situation. Accordingly, any price regulation of energy resources might require the allocation of such resources in order to insure that sufficient supplies remain available for domestic consumption.

Pursuant to the new authority, the Director of the Office of Energy Policy (to whom the authority has been delegated) has already put into effect mandatory allocation programs for supplies of propane (EPO Reg. 3, 38 F.R. 27397, October 3, 1973) and middle distillates (EPO Reg. 1, 38 F.R. 28660, October 16, 1973). Middle distillates are defined as any derivative of petroleum, including kerosene, jet fuel, home heating oil, and diesel fuel, which have a fifty percent boiling point in the ASTM D86 standard distillation test between 350° and 700° F. Procedural regulations for these programs have been published as EPO Reg. 7 (38 F.R. 29330, October 24, 1973).

Natural Gas and Electricity

The exportation of natural gas and electric energy is controlled by the Federal Power Commission (FPC) under the authority of the National Gas Act (15 U.S.C. 717b). To obtain a license to export natural gas and electric energy, an application must be filed with the FPC (18 C.F.R. 1.5) and accompanied by a fifty dollar filing fee (18 C.F.R. 159). Executive Order No. 10485 of September 3, 1953 (18 F.R. 5397), empowers the FPC to issue permits for the construction, operation, maintenance, or connection at U.S. borders of facilities for the transmission of electric energy to a foreign country and for the importation or exportation of natural gas. Before issuance of a license, there must be a determination of consistency with the public interest and favorable recommendations by the Secretaries of State and Defense.

Atomic Energy

The Atomic Energy Act of 1954 provides the Atomic Energy Commission with full authority to regulate the export of nuclear energy resources. Nuclear source materials and byproducts may not be exported, except pursuant to license by the Commission.

Exports of Energy Resources

EXPORTS—1968 TO 1972

Crude oil and petroleum products.—Total exports increased annually from 1968 to 1970 and declined in 1971 and 1972. Crude oil exports also peaked in 1970 and since have decreased significantly, going from 4,991,000 barrels in 1970 (or 0.1 percent of production) to 187,000 barrels in 1972 (or 0.005 percent of production). Important petroleum product exports have been of coke, petroleum lubricants, liquefied gases, and residual fuel oils, due to the availability of foreign markets for these commodities. In 1972, coke exports went principally to Europe, Japan, Canada, and Mexico. Petroleum lubricants were exported mainly to Brazil, Canada, Japan, and the United Kingdom; ninety percent of the exports of liquefied gases went to Mexico; and residual fuel oil exports went largely to Canada, Mexico, and the United Kingdom.

Coal.—Coal exports in the period 1968–72 peaked in 1970, thereafter declining. Bituminous coal accounted for 98 percent of total coal exports in 1972 or approximately 10 percent of bituminous production. In 1972, Japan and Canada received 64 percent of the total bituminous coal exports, and Canada received about 64 percent of the total anthracite coal exports.

Natural gas.—Canada, Mexico, and Japan were our only export markets over the 1968–72 period. Canada and Mexico received natural gas via pipeline transmission, while Japan, starting in 1969, received liquefied natural gas shipments from Alaska. Japan was our largest export market in 1972, receiving over 50 percent of out total natural gas exports. Total exports of natural gas in 1972 were but 0.4 percent of production.

Electricity.—For purposes of the Tariff Schedules of the United States (TSUS), electricity is considered an intangible and not subject to the provisions of the schedules, with the result that it is not subject to a duty and, therefore, no statistics are published by the Department of Commerce. Similarly, there is no Schedule B number for electricity exports, so that there are also no Department of Commerce statistics published for exports.

The FPC collects import and export data for electricity as part of their licensing procedure. For 1972, exports to Canada were $2.8 million, while imports were $61.8 million. Essentially all of this trade occurred within the U.S. east coast to Michigan. Exports to Mexico in 1972 were $3.8 million, while there were no imports. The exports all originated in Texas, Arizona, and California.

Exports—1973 vs. 1972

Crude oil and petroleum products.—Total exports for the first seven months of 1973 increased about 10 percent over the same period in 1972. Both petroleum products and crude oil exports increased. However, total exports are only about one percent of production.

Coal.—Total exports of coal decreased in the first seven months of 1973 relative to the first seven months of 1972. Both anthracite and bituminous coal exports decreased.

Natural gas.—Natural gas exports increased about 10 percent in the first seven months of 1973 relative to 1972 but remained small compared to production at less than one half of one percent.

Fossil fuels: U.S. exports summary table, by products, 1968–72

Product	1968	1969	1970	1971	1972
	Quantity [in thousands of barrels]				
Petroleum lubricants	18,001	16,397	16,094	15,823	14,995
Liquefied gases	10,608	12,798	9,955	9,379	11,469
Residual fuel oils	20,013	16,891	19,786	13,186	12,060
SBP naphthas	2,427	2,019	1,585	1,455	1,487
Total gasoline	2,083	2,449	1,368	2,287	954
Distillate fuel oils	1,547	1,753	899	2,924	1,214
Jet fuel	2,092	1,730	2,093	1,536	957
Kerosene	613	154	124	179	89
Crude petroleum	1,802	1,436	4,991	507	187
Other [1]	25,358	29,258	37,348	34,569	38,056
Total	84,544	84,885	94,243	81,845	81,468
	Quantity [in thousands of short tons]				
Anthracite coal	518	627	789	671	780
Bituminous coal	50,637	56,234	70,908	56,633	55,960
Total	51,155	58,681	71,697	57,304	56,740
	Quantity [in billions of cubic feet]				
Natural gas	94	51	68	84	91

[1] Mainly petroleum coke, although other exports of wax, asphalt, road oil, petrochemical feedstock, and other miscellaneous products are included.

Source: Crude petroleum and products statistics compiled from Bureau of Mines data. Coal statistics compiled from Department of Commerce data. Natural gas statistics compiled from FPC and Department of Commerce data.

Fossil fuels: U.S. exports summary table, by products, January–July 1972, and January–July 1973

Product	January–July 1973	January–July 1972
Thousands of barrels:		
Crude oil	360	187
Refined products	49, 860	45, 026
Total	50, 220	45, 213
Thousands of short tons:		
Anthracite coal	392	339
Bituminous coal	28, 360	30, 755
Total	28, 752	31, 094
Billions of cubic feet: Natural gas	52	49

Source: Crude petroleum and products statistics compiled from Bureau of Mines data. Coal statistics compiled from Department of Commerce data. Natural gas statistics compiled from FPC and Department of Commerce data.

VI. Summary of Facts

This document has sought to raise more questions than it answers. Its central theme was raised on the first page: "Should fiscal policy be employed to mitigate the current energy shortage and to assist in the transition to alternative energy sources?" A host of related questions were also raised at the outset which will be the focus of the subcommittee's hearings. The factors pointing to the underlying need for a national energy policy have been made abundantly clear:

The U.S. with 6 percent of the world's population, consumes one-third of the world's captive energy;

Domestic production of fossil fuels peaked in November 1970, and by 1972 was down 5 percent despite removal of all production restraints;

The U.S. has a large resource base of fossil fuels sufficient to meet its needs for several hundred years; but most of these resources are a long way from development;

The capital requirements for developing U.S. resources are enormous—running into the hundreds of billions over the next decade;

While import policies have historically played a major role in preserving stable domestic prices, this is no longer the case;

Imports are not a long-term solution to the energy gap; they will not even be available to cover our short-term needs;

Foreign oil is now more than twice as expensive as domestic oil; however, given the much lower costs of production in the major oil producing nations of the Middle East, and the ability of these countries to charge whatever the market will bear, a U.S. national energy policy must encourage investment in our own plentifiul resources (for example, through a variable import levy);

Academic studies indicate that Federal regulation of natural gas at the well head has been primarily responsible for the severe natural gas shortage that we are experiencing today;

The implications of the energy shortage for the U.S. economy are quite serious—unemployment and price inflation may result from reduced output;

The balance of payments effects of relying on foreign energy cannot be accurately projected into the future as price and availability of fuel remains uncertain; nevertheless, under reasonable assumptions the effects are large enough to lead to serious international monetary instability;

Perhaps a more important question than the balance of payments effects is whether we will be able to get the fuel when we need it; and at what price?

The United States exports a considerable amount of its coal production;

If utilities and commercial users of energy are to switch from natural gas to coal, they will have to be assured of an available supply of coal; the same can be said of huge investments in coal gasifiers which can become commercially operational in about 2 years;

The implications of the energy shortage on our defense posture have not been fully explored;

The Defense Department traditionally has depended on foreign suppliers for about half its needs (DOD projected consumption in FY 74 was 670,000 barrels per day).

In response to the need to increase supply and decrease demand for energy, the Committee may wish to consider tax measures, both incentives and disincentives. These tax incentives (or disincentives) may be viewed either in conjunction with, or as alternatives to, a free price mechanism for domestic fossil fuels.

On the supply side, various tax incentives have been suggested for:

(*a*) developing our domestic sources of energy;

(*b*) developing alternative sources through research and development programs;

(*c*) financing mandatory conversions of electric power plants from petroleum or natural gas to coal;

(*d*) encouraging capital investment in mid-range energy altenratives.

(*e*) An "energy trust" fund has been suggested as a means of insuring adequate financing of research and development and other expenditures needed over the next decade to insure "energy independence".

On the demand side, tax disincentives have been suggested for restraining overall and/or wasteful consumption.

(*a*) consumption taxes or a tax at the source (BTU tax) have been suggested as a means of financing the energy trust fund;

(*b*) the alternative consumption taxes that have been suggested include: a tax on gasoline at the pump, and/or a manufacturers auto excise tax based on gas mileage;

The U.S. lacks a national energy policy. The country needs a comprehensive program of energy conservation and development—one which is consistent with the nation's environmental, economic and national security goals.

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Appendix A

White House Fact Sheet on Energy

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OFFICE OF THE WHITE HOUSE PRESS SECRETARY, THE WHITE HOUSE

Fact Sheet—the President's energy emergency address
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Previous Presidential Statements on Energy.
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- All energy sources.
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BACKGROUND

In the President's Energy Message of April 18, the President characterized the energy situation facing the country as a problem, but not a crisis.

While we were faced with a tight supply situation this winter, particularly in home heating oil, we felt that voluntary conservation efforts, coupled with increased imports would allow us to balance the supply and demand.

However, as a result of the actions taken in the Middle East, our ability to import has not increased, but has in fact declined. Therefore, the energy problem has become much more severe.

CURRENT SITUATION

Recent oil curtailments will mean a shortage this winter of between 2 and 3 million barrels per day of crude oil and products—or 10 to 17% of expected demand.

Current shortages are approximately 10% of demand.

If the oil cutoff continues as petroleum demand increases during the winter, the overall shortage will rise toward the 3 million barrels per day level—17% of demand.

At the current 2 million barrels per day level, the total shortage in major fuels are:

> Distillate fuels—including heating oil, diesel fuel and kerosene—at least 450,000 barrels per day or 11% short of expected demand. (Heating oil shortages are expected to be over 15% short of demand.)
>
> Residual fuel oil—which is used primarily by electric utilities, industrial operations and for heating large buildings—is approximately 500 thousand barrels per day or 13% short of expected demand.
>
> Jet fuel—at least 100 thousand barrels per day or 13% short of commercial and private use.
>
> Gasoline—at least 500,000 barrels per day or 7% short of demand. Expected shifts in refinery output to higher production of heating oil at the expense of gasoline could decrease the shortage of heating oil and increase the shortage of gasoline by as much as 200,000 barrels per day.

ACTIONS NOW BEING TAKEN BY THE ADMINISTRATION

The following actions are being taken by the Administration, primarily under the authority of the Economic Stabilization Act of 1970 and the Defense Production Act of 1950.

REDUCE RESIDUAL OIL CONSUMPTION

Regulations are being issued which prevent utilities and industrial facilities from switching from coal to petroleum fuels to reduce the growing demand for residual oil.

Utilities will be encouraged and, where possible, required to convert power plants currently using residual oil to coal.

46 power plants have indicated a capacity to convert within 60 days, with a potential savings of residual oil of 400,000 barrels per day.

Actual conversions will depend upon such factors as the availability of coal, transportation and storage facilities, and variances from State Clean Air restrictions.

REDUCE JET FUEL CONSUMPTION

The Federal Aviation Administration is continuing to work with airlines on actions to reduce fuel consumption, such as reducing speeds and limiting the amount of taxiing. This will save an estimated 20,000 barrels per day.

New steps will be taken under the fuel allocation program to distribute available jet fuel equitably among commercial and other jet fuel users. Shortages could result in a 10% reduction in scheduled flights.

REDUCE HEATING OIL CONSUMPTION

Thermostats in Federal buildings will be reduced to 65–68°, leading to a 19% reduction from last year in energy required for heating—or the equivalent of 40,000 barrels of oil per day during the winter.

The President asked that:

Thermostats in homes be reduced by 6°, to reach a national daytime average of 68°.

Offices, factories and commercial establishments achieve the equivalent of a 10° reduction through lowering thermostats or curtailing working hours. (An estimated 450,000 to 600,000 barrels per day of heating oil could be saved by these actions).

Homeowners and businesses that heat with electricity and natural gas make the same sacrifices as those using oil.

Plans are being developed to control consumption of heating oil through rationing, if that proves necessary. A proposed plan will be published in the *Federal Register* in about 4 weeks. In addition, control fees are being considered to dampen excessive use of natural gas and electricity.

REDUCE GASOLINE DEMAND

The President has directed that operators of all Federal motor vehicles observe a 50 MPH speed limit.

The President asked Governors, Mayors and the general public to take steps to reduce gasoline use. Possible steps include:

Make greater use of mass transit and car pools. An increase in the average car occupancy for commuter trips from the current 1.6 persons to 2.5 persons would save approximately 400 thousand barrels per day.

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Reduce speeds on highways within their states to a maximum of 50 MPH.

State and local governments can discourage automobile use by:

Setting aside bus lanes.

Establishing higher parking taxes.

Blocking off certain city sectors to cars with only one occupant.

Providing preferential parking for car pools.

State and local governments can stagger working hours to smooth traffic flow and increase use of public transit.

The President directed the Secretary of Transportation to give priority to grant applications for the purchase of buses for mass transit under the authority of the Federal Aid Highway Act of 1973 and the Urban Mass Transportation Act. (Approximately $1.8 million per year is available for urban highway and urban mass transit capital assistance).

A plan for rationing of gasoline is being developed and will be implemented if necessary.

OTHER PRESIDENTIAL ACTIONS

Directed the Office of Management and Budget to establish an interagency task force to monitor the allocation and rationing programs and develop plans for dealing with the expected shortage.

Directed the Secretary of Interior to establish a fuel allocation administration to administer all energy allocation and rationing programs.

Directed the Secretary of Commerce to establish a National Industrial Energy Conservation Council to promote conservation in industry.

Directed the Secretary of the Interior to active the Emergency Petroleum Supply Committee, which consists of oil company officials and serves in emergencies to gather information on imported petroleum supplies and their transportation.

Energy companies should not take advantage of the current oil shortages to gain excessive profits. If necessary the Economic Stabilization Act will be used to insure that the companies do not benefit unduly.

OTHER STATE AND LOCAL ACTIONS

Governors and Mayors that have not yet done so are being asked to establish energy emergency offices or committees to:

Determine the energy supply and demand situations in their areas.

Develop and implement actions to reduce energy demand.

Coordinate activities to assist those who do not have adequate fuel supplies.

Work with Federal agencies that are allocating fuel.

Current emergency authority available by the President for dealing with the energy emergency is largely limited to:

Defense Production Act of 1950, as amended, which provides broad authority including authority to allocate and control the use of materials for National security purposes.

Economic Stabilization Act of 1970, as amended, which provides authority to allocate petroleum as well as authority to control prices and wages.

Export Administration Act of 1969, as amended, which provides authority to restrict exports.

At the President's direction, Energy Policy Advisor John Love and other Administration officials have been working with the Congress over the past two weeks to identify new authority needed to respond in a timely fashion to an energy emergency.

Legislation is needed for action in an energy emergency in the following areas:

Authorize mandatory energy conservation measures such as:

Curtailing outdoor electrical advertising and ornamental lighting (ornamental gas lights use an amount of natural gas equivalent to 35,000 barrels per day or enough to heat 175,000 homes).

Reducing commercial operating hours.

Reducing speed limits.

Imposition of energy conservation fees or taxes, such as on consumption of natural gas or on excessive uses of electric energy.

Give Congressional approval to:

The finding by the Secretary of the Navy (approved by the President) that increased production from the Elk Hills Naval Petroleum Reserve is needed for national defense purposes. (160,000 barrels of oil per day—8% of current shortages—could be obtained from Elk Hills within 60 days).

Use of proceeds from sale or exchange of the Navy owned oil to fund further development and production from Elk Hills and for exploration and proving Naval Petroleum Reserves, especially NPR #4 in Alaska.

Authorize the use of daylight savings time throughout the year. (This could reduce electricity and heating demands, particularly in Northern areas, by as much as 3%).

Authorize the President, acting through the Administrator of EPA to exempt (grant waivers) stationary sources from Federal and State air and water quality laws and regulations. There would be no change in Federal or State standards. Rather, there would be a case-by-case review by the Environmental Protection Agency with authority for the Administrator of EPA to grant waivers, without notice or hearing, and to override state or local regulations, if necessary. Relaxation would generally be limited to one year except where longer periods are necessary to make conversions to alternative fuel economically feasible.

Authorize the President to exempt actions taken under the proposed energy emergency act from the National Environmental Protection Act (NEPA). However, an environmental evaluation of substantive content similar to an environmental impact statement would be required prior to the action, if possible, but within 60 days in any event. Actions in effect over one year would become subject to the full NEPA requirements.

Upon declaration of an emergency by the President, regulatory agencies (FPC, CAB, ICC, FMC, and AEC) would:

consider energy use and conservation as part of their public interest determinations, and,

in the case of the transportation agencies, be authorized, after summary hearings, to adjust a carrier's operating authority in such respects as: number of trips, points served, and rate schedules, and,

in the case of the FPC, be authorized, for the duration of the energy emergency to suspend the regulation of prices of new production of natural gas, and,

in the case of the AEC, be empowered to grant a temporary (up to 18 months) operating license without a public hearing, but subject to all safety and other requirements of its act.

ORGANIZATION AND FUNDING FOR ENERGY R & D

The President is requesting the Congress to give priority attention to the establishment of ERDA, separate and distinct from DENR in order to move ahead rapidly with the creation of a strong management framework for developing energy technology.

On June 29, 1973, the President proposed to Congress legislation to establish a Department of Energy and Natural Resources (DENR), Energy Research and Development Administration (ERDA), Nuclear Energy Commission (NEC).

The creation of ERDA will also result in a corresponding reorganization of the AEC's regulatory functions into an independent NEC.

The President also directed authorizing legislation for the 5-year—$10 billion energy R & D program that he announced on June 29, 1973 be forwarded to Congress to provide the necessary funds for ERDA.

OTHER ADMINISTRATION LEGISLATIVE PROPOSALS ON ENERGY AWAITING CONGRESSIONAL ACTION

The President again asked that the Congress act on the following legislative proposals needed to improve our longer term energy situation:

During this session:
- Alaska Pipeline
- Natural Gas Supply Act
- Mined Area Protection Act (Surface mining)
- Deepwater Port Facilities
- ERDA/NEC Reorganization

Early next session:
- Electrical facilities siting
- DENR

PREVIOUS PRESIDENTIAL STATEMENTS ON ENERGY

June 20, 1971 Message to the Congress on Clean Energy.

April 18, 1973 Message to Congress on National Energy Policy.

June 29, 1973 statement on Energy Conservation, R & D and Organization.

October 9, 1973 statement on Energy Conservation.

October 11, 1973 statement on Energy R & D, including added funds for FY-74.

Data on sources and uses of energy, 1972

All energy sources:	
Petroleum (including natural gas liquids):	
Million barrels	5, 960
Trillion Btu	32, 812
Percent	46
Natural gas:	
Billion cubic feet	22, 607
Trillion Btu	23, 308
Percent	32
Coal (bituminous, anthracite and lignite):	
Thousand short tons	571, 053
Trillion Btu	12, 428
Percent	17
Hydropower:	
Billion kilowatt-hours	280. 2
Trillion Btu	2, 937
Percent	4
Nuclear power:	
Billion kilowatt-hours	56. 9
Trillion Btu	606
Percent	1
Total gross energy (trillion Btu)	72, 091

All energy uses:

The 1972 figures show that consumption by major consuming sectors was fairly evenly divided:

	Percent
Industrial	28. 8
Electricity generation	25. 6
Transportation	25. 0
Household and commercial	20. 6

When electrical generation is factored into the other sectors, the breakdown is as follows:

Industrial	43. 0
Commercial	14. 0
Residential	19. 0
Transportation	24. 0

Petroleum:

At present the United States depends upon petroleum to meet approximately one-half of its energy demand.

On the average for 1973, petroleum use is approximately 17 million barrels per day.

Imports accounted for approximately 33% of all crude oil and petroleum products prior to the recent curtailments.

The table below shows United States imports of crude oil and products.

U.S. Imports of Crude Oil and Products

[Figures for 2d Quarter 1973—in thousands of barrels per day]

Source	Crude oil	Products	Total
Venezuela	326. 8	599. 5	926. 3
Other Caribbean	62. 5	746. 2	808. 7
Canada	1, 036. 7	330. 2	1, 366. 9
Mexico	2. 7	14. 9	17. 69
Other Western Hemisphere	47. 8	551. 1	598. 9
Non-Communist:			
Europe		183. 2	183. 2
Egypt	20. 8		20. 8
Other North Africa	294. 3	42. 4	336. 7
West Africa	466. 9	13. 1	480. 0
Israel	3. 4		3. 4
Iran	207. 0	2. 6	209. 6
Other Mideast	487. 7	62. 1	549. 8
Japan		2. 2	2. 2
Indonesia	205. 2	3. 5	208. 7
Other Eastern Hemisphere		18. 0	18. 0
Rumania		6. 4	6. 4
U.S.S.R		24. 9	24. 9
Totals	3, 161. 9	2, 600. 3	5, 762. 2

Appendix B

Summary of Principal Provisions of the Internal Revenue Code Affecting Energy Resources, Production, and Consumption

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Summary of Principal Provisions of the Internal Revenue Code Affecting Energy Resources, Production, and Consumption

The following material summarizes the principal provisions of the Internal Revenue Code which directly affect energy resources, production and consumption. Excluded are State and local taxes affecting energy, and a number of minor provisions of the Federal income tax law which relate to energy. Brief mention is made of general provisions such as the investment credit and accelerated depreciation which do not specifically pertain to the energy industry but affect it just as other industries are affected. No discussion is included regarding the use of the tax laws to establish drilling funds as tax shelters.

INCOME TAX PROVISIONS

Depletion

Allowances for the depletion of mineral deposits are made in the from of deductions from gross income by owners of oil and gas wells and of mines (including coal and uranium). These deductions enable the owner to deduct his investment in the well or mine from his income over a period of years for income tax purposes, just as other businesses are allowed deductions for depreciation. In addition, deductions for depreciation are available to operators of mines and wells with respect to certain capital expenditures. The deduction for depletion is authorized under Section 611 of the Internal Revenue Code and must be the larger of cost depletion (Section 612) or percentage depletion (Sections 613–614). Cost depletion is akin to depreciation while percentage depletion is a special method wholly unrelated to actual investment. It is based on gross income.

1. *Cost depletion.*—Cost depletion is computed in relation to the cost of the property subject to certain adjustments. In a more technical sense it is based on the "adjusted basis" of the property which would be used to determine the gain on the sale or other disposition of the property. Cost depletion is generally used to recover the costs of acquiring the property (leases, geological costs, sales price of land). The cost is reduced each year by any depletion deductions taken. Cost depletion is computed by multiplying the adjusted basis of the property by the ratio of the units of the product produced and sold during the year to the estimated total units that will be produced over the remaining life of the property. For example, in the case of an oil well, if

the adjusted basis is $50,000, and 500,000 barrels of oil are expected to be produced over the remaining life of the well and 50,000 are produced and sold during the year, the cost depletion would be:

$$\frac{50{,}000}{500{,}000} \text{ times \$50,000 equals \$5,000}$$

For the next year, the $5,000 cost depletion will reduce the cost basis to $45,000 and the prior year's production of 50,000 barrels will reduce estimated production to 450,000 barrels. Assuming production of 50,000 barrels in the second year the cost depletion will be:

$$\frac{50{,}000}{450{,}000} \text{ times \$45,000 equals \$5,000}$$

The "basis" used for depletion purposes is reduced by cost depletion or percentage depletion taken. When the adjusted basis reaches zero, cost depletion ceases, though percentage depletion is permitted to continue indefinitely. At any time the property becomes abandoned, the entire remaining basis, if any, for cost depletion may be written off in the year of abandonment.

The cost of certain tangible equipment attached to a well, such as pumps, may be either separately depreciated under methods allowable for depreciation, or written off by the "unit production method" at the same rate as applies to cost depletion. Other tangibles are subject to depreciation for purposes of recovering their cost.

2. *Percentage depletion.*—Percentage depletion is not related to the cost of a property but is a percentage of gross income from the property. This method of capital recovery is employed when it exceeds cost depletion. When used it reduces the remaining basis for cost depletion. The percentage depletion rates prescribed in Section 613(b) are 22% for oil, gas, and uranium, and 10% for coal. Gross income from the property is defined in Section 613(c) and means in the case of oil and gas the price at the wellhead. In the case of uranium, coal, and oil shale, certain treatment processes and transportation expense may be applied before determining value of the mineral for purposes of determining "gross income from the property".

In the case of coal, cleaning, breaking, sizing, dust allaying, treating to prevent freezing and loading for shipment are allowed as treatment processes. In the case of uranium, crushing, grinding, beneficiation by concentration, cyanization, leaching, crystallization, precipitation (but not electrolytic deposition, roasting, thermal or electric smelting, or refining) are allowed. In the case of oil shale, extraction, crushing, loading into retort and retorting are allowed but not hydrogenation, refining or any process subsequent to retorting. Ore may be valued for percentage depletion purposes after being transported up to 50 miles (or further if the Secretary of the Treasury determines it is necessary) from the place of extraction to treatment facilities.

Percentage depletion has also been allowed for geothermal wells. As a result of litigation, it has been decided that geothermal wells are gas wells and entitled to a depletion rate of 22%. This result was obtained after it was concluded that the well constituted an exhaustible source of gas (water vapor). It is believed that some geothermal wells may be inexhaustible. Such wells would not be entitled to percentage depletion in that event.

The percentage depletion deduction may not exceed (under Section 613(a)) 50% of taxable income from the property computed before the allowance for depletion, i.e. after all deductions other than depletion. For example, if gross income from a property is \$100,000, the depletion deduction in the case of oil would be \$22,000. However, if taxable income before depletion (gross income minus any other deductions) is only \$40,000, then only \$20,000 of the depletion deduction may be taken. Because of this limitation as well as the concept "gross income from the property" the determination of what constitutes a property is important. The general rule is that each separate interest in each mineral deposit in each separate tract or parcel of land is a separate property. However, certain aggregations are allowed. In the case of oil and gas, all operating interests within a single tract may be treated together or separately. This rule is liberalized in the case of operating interests subject to a unitization or pooling arrangement. In the case of other minerals, the taxpayer may elect to aggregate one or more operating interests if the interests are in the same operating unit. However, no interest in a particular mine may be excluded from an aggregation if other interests in the mine are included.

Each taxpayer with a direct economic interest may take percentage depletion on his share of the gross income. The operator deducts royalty payments from the gross income of the property before he computes his depletion allowance and the royalty holder takes depletion on the share of the depletion represented by his royalty. When computing the 50% limitation, the operator begins with the gross income less royalty payments, and computes taxable income by deducting all expenses.

Current Expensing of Certain Costs

The income tax law allows certain expenses of exploration and development of mines and wells to be deducted currently rather than to be capitalized and deducted ratably over the life of the property. The advantage of deducting expenses currently rather than capitalizing them is that current deduction results in deferral of taxes. This advantage is reenforced by the fact that the value of the deferral is increased by the interest effect. In addition, when expenses are deducted, percentage depletion may also be taken, whereas if the expenses are capitalized, only cost depletion would be available. The provisions for oil and gas are quite different from those for the hard minerals.

1. *Expensing of intangible drilling costs (oil and gas).* Certain expenses incurred in bringing a well into production, such as labor, materials, supplies and repairs, are considered intangible drilling costs. (Tangible expenses are those for assets such as tanks, drilling tools, casings, tubing and pipes.) Although intangible drilling costs are actually of a capital nature (expenses for an asset which will produce income over a number of years), Section 263(c) allows the taxpayer the option of deducting them currently (in the year the costs are incurred) rather than capitalizing them and deducting a portion of the costs over each year of useful life. Regulations are prescribed under Section 612. If intangible expenses are currently deducted, they are not added to basis for cost depletion. Moreover, they do not reduce percentage depletion except to the extent they reduce net income for purposes of the 50% limitation. If the election to deduct currently is not made, these expenses are capitalized and must be recovered through cost depletion.

2. *Expensing of exploration and development costs (hard minerals).* Mining exploration and development costs may be deducted currently (Section 616–617). Mining exploration costs are those for the purpose of ascertaining the existence, location, extent or quality of a deposit, paid or incurred before the development stage (such as core drillings and testing of samples). These expenses are limited in the case of foreign exploration so that total foreign exploration costs cannot be expensed after the taxpayer has taken total deductions, foreign and domestic, of $400,000. Development expenses are those incurred during the development stage of the mine and include expenses such as constructing a shaft and tunnel and in some cases drilling and testing to obtain additional information for planning operations. There are no limits on the current deductibility of development expenses.

Deductions of mining development costs are in addition to percentage depletion. Exploration expenditures deducted currently may subsequently reduce percentage depletion deductions. Also, there is a recapture provision for exploration costs deducted but not for development costs deducted. That is to say, if the property is sold, a portion of the gain may be required to be treated as ordinary income.

Capital Gains Treatment of Coal Royalties

Section 631 allows coal royalties to be treated as long term capital gains in cases where the taxpayer held the deposit for at least six months prior to leasing it in exchange for royalties from production. Long term capital gains taxation is at a lower rate than the tax on ordinary income.

Minimum Tax

The minimum tax has the effect of reducing to some degree certain tax advantages available to the energy industry.

Percentage depletion taken after the basis for cost depletion has been reduced to zero is one of the preference items subject to the minimum tax (Sections 56–58). Another tax preference item is the capital gains treatment described above for coal royalties.

The minimum tax is levied on the aggregate of preference items after subtraction of $30,000 of preference income and an additional amount equal to the taxpayer's regular income tax. For example if a taxpayer had tax preferences of $100,000 and regular tax of $50,000, his minimum tax would be $2,000 ($100,000 minus $80,000 times 10%).

Foreign Tax Credit

A second provision which may be said to provide special benefits for the oil and gas industry is the foreign tax credit (Section 901–906). The foreign tax credit is available to all taxpayers and allows them to credit foreign income and similar taxes against their U.S. tax liability, thus reducing the U.S. tax liability dollar for dollar. The purpose of this provision is to prevent double taxation of foreign income brought back to the U.S. The foreign tax credit is limited to the amount of tax paid on income earned in foreign countries and cannot be used to offset tax on U.S. source income. Taxpayers may choose between two methods for determining the extent of the credit: the per-country limitation limits the credit for taxes paid *to each country* to the same proportion of total Federal income taxes that reported income received from that country bears to total income; the overall limitation limits the credit for taxes paid *to all foreign* countries to the same proportion of Federal income tax that all foreign income bears to total income. Allowance of the overall limitation permits the taxpayer to use excess foreign tax credits from a high tax country to offset Federal income tax on foreign income, such as shipping income, subject to little or no foreign tax.

The foreign tax credit is particularly important to international oil companies who account for almost one half of the foreign tax credits claimed by corporations subject to U.S. taxation.

Because of the existence of percentage depletion under U.S. but not foreign law, foreign oil operations are generally taxed at a lower level by the U.S. than by the foreign government. This results in excess foreign tax credits which may offset U.S. tax on foreign non-mineral income. Thus, in 1969, a provision was added to disallow the use of excess foreign tax credits arising from the excess of percentage over cost depletion to reduce U.S. taxes on foreign non-mineral income.

Another area of interest relating to the foreign tax credit as applied to the energy industry is the issue of whether the income tax levied by the foreign government on oil production is in fact a tax. In the foreign oil-producing countries, the rights to land are generally held by the governments rather than private individuals and, therefore, royalties are paid to these governments. However, if these royalties are paid in the form of income taxes then they may be credited against income tax, rather than deducted from income, reducing taxes dollar for dollar rather than 48 cents for each dollar. Moreover, the oil companies may then include these amounts in gross income for purposes of computing percentage depletion. If they were considered royalties, percentage depletion could not be taken on the government's share of the gross income. Some have argued that the large income taxes paid by American companies to the petroleum exporting countries are actually royalties and that treating them as income taxes results in preferential treatment of oil production in foreign countries.

EXCISE TAX PROVISIONS

Excise taxes are imposed at varying rates on a number of fuels. Credits are allowed to the consumer against income tax in some cases where fuel was not used in a certain manner; as for example for non-highway use.

Manufacturer's Excise Taxes

Gasoline.—4 cents a gallon (a credit is allowed if used on a farm for farming purposes or if used for non-highway purposes other than noncommercial aviation; a 2 cent per gallon credit is allowed for use in local mass transit) Section 4081–4084.

Lubricating oil.—6 cents per gallon (a credit is allowed if not used in a highway vehicle) Section 4091–4094.

Retailer's Excise Taxes

Gasoline used in non-commercial aviation—3 cents per gallon Section 4041(c)(1).

Fuels other than gasoline used in non-commercial aviation—6 cents per gallon Section 4041(c)(2).

Diesel fuel used in highway motor vehicles—4 cents per gallon (a credit is allowed if used on a farm for farming purposes or if used in local mass transit)—Section 4041(a).

Special motor fuels (benzene, benzol, naptha, etc.)—4 cents per gallon (if used in a non-highway motor vehicle or motor vehicle or motor boat the tax is 2 cents per gallon)—Section 4041(b).

Although these taxes are imposed on the manufacturer or retailer they are included but generally stated separately in the price to the consumer. Certain types of sales are exempt such as those to State and local governments, tax-exempt educational organizations, sales for export and sales for resale.

Appendix C

Balance of Payments Effects of Energy Imports

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Department of Commerce—Balance of payments, effects of energy imports—Balance on current account and long-term capital (basic balance of payments)

[Billions of dollars]

	1970	1975	1980	1985
Consuming countries:				
United States	2.3	−7.0	−12.0	−0.8
West Europe	−3.9	−17.7	−27.0	−16.4
Japan	−.3	−8.3	−21.8	−39.8
Canada	−0	−0	−1.3	−1.5
Other free world	.3	.2	−3.9	−8.0
Subtotal	−1.7	−32.9	−66.1	−66.5
Producting countries:				
Venezuela	.2	3.7	2.5	−0
Algeria	.0	.9	1.1	0
Libya	.7	2.8	3.3	.6
Nigeria	0	3.5	7.3	4.1
Iran	0	7.2	10.0	3.6
Iraq	.1	.9	8.3	18.0
Kuwait	.1	1.8	2.5	2.4
Qatar	.1	1.1	1.5	1.1
Saudi Arabia	.3	6.7	19.3	25.8
Union of Arab Emirates	.1	3.3	8.0	11.0
Indonesia	0	1.1	2.3	.1
Subtotal	1.7	32.9	66.1	66.6
Total	−0	0	0	0

N.B.—These data retain the basic assumptions of the attached technical staff paper with the exception of a $1.50 transport fee from the Persian Gulf to the United States and a world price of $5 per barrel in 1973 rising to $10 fob in 1980.
Source: U.S. Department of Commerce.

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Balance on current account

[Billions of dollars]

	1970	1975	1980	1985
Consuming countries:				
United States	2.4	−13.2	−25.7	−16.0
West Europe	−4.0	−24.3	−41.8	−33.1
Japan	−.4	−11.4	−30.1	−50.8
Canada	−.2	−.4	−1.7	−1.9
Other free world	−.2	−6.3	−19.3	−27.2
Subtotal	−2.5	−55.6	−118.6	−129.1
Producing countries:				
Venezuela	0	3.7	2.5	0
Algeria	0	1.6	2.1	−.1
Libya	.9	4.5	5.3	.9
Nigeria	−.2	3.3	7.1	3.8
Iran	.1	11.0	15.3	5.4
Iraq	.2	1.4	12.7	27.7
Kuwait	.5	4.5	6.4	5.9
Qatar	.1	1.9	2.6	1.9
Saudi Arabia	.7	16.9	48.3	64.3
Union of Arab Emirates	.2	5.7	14.1	19.2
Indonesia	−0	1.1	2.3	0
Subtotal	2.5	55.6	118.6	129.1
Total	0	0	0	0

TECHNICAL NOTE

ENERGY AND THE BALANCE OF PAYMENTS

(This technical staff paper details the methodology of one analytical tool for understanding the magnitude and direction of the future energy problem. It does not represent the official views of the Department of Commerce or the U.S. Government.)

(Research and Planning Staff, Domestic & International Business Administration, U.S. Department of Commerce, October 18, 1973.)

Energy and the Balance of Payments

Table of Contents

Summary

A comprehensive computer program developed by the DIBA Research and Planning Staff, Department of Commerce, has been designed for the systematic examination of balance of payments impacts of various national and global energy projections. The oil-related current account and basic payments balances and their elements have been projected for 1975, 1980, and 1985 for five oil consuming countries/regions and eleven major oil exporting countries.

Factors taken into account include total energy production and consumption, oil prices, transportation costs and patterns, oil earnings, imports of oil producing countries, and capital flows for oil exploration, participation payments and long-term investments by the producing countries. The analysis has many limitations, and considerable uncertainty surrounds many of the assumptions; accordingly, appropriate sensitivities have been developed.

The computer program and assumptions will be updated periodically as economic environment changes dictate. The program can be used at anytime to examine the balance of payments impacts of variations in underlying policy or economic assumptions, both quickly and at minimal cost.

The "Illustrative Case" described in this paper indicates how the oil-related annual current payments accounts of each of the United States, Western Europe, and Japan react relative to the oil producers' current accounts from 1970 to 1980 under a given set of assumptions. The data used is also illustrative and may not necessarily agree with comparable data used in other applications.

Introduction

This is a technical staff paper detailing the methodology of one analytical tool for understanding the magnitude and direction of the future energy problem. It does not represent the official views of the Department of Commerce or the U.S. Government.

Starting in February 1973, the Research and Planning Staff of the Domestic and International Business Administration, Department of Commerce, undertook the assembling of appropriate input information and the development of a computer program to calculate current account and basic payments balances for five oil importers and eleven oil exporters. The balances are keyed to oil because oil is the incremental energy source. However, examination of the impact of non-oil energy sources is possible because the input includes all basic energy sources (coal, gas, nuclear, hydroelectric, and other) for the free world.

The main value of the program and the output is the quantification of differential effects for the various countries—over time and relative to each other. The computer program covers the years 1970, 1975, 1980, and 1985, but the time periods can be changed if desired. The absolute balances of each case have been drawn from the assumptions. Considerable effort has been expended to insure that each assumption is stated explicitly. As a result, the differences between cases are meaningful.

METHODOLOGY

The computer program calculates the oil-related current account balances and basic payments balances for the following consuming and producing countries or regions.

Oil consumers (5)	Oil producers (11)
United States	Venezuela.
Western Europe	Algeria.
Japan	Libya.
Canada (also an exporter)	Nigeria.
Other free World	Iran.
	Iraq.
	Kuwait.
	Qatar.
	Saudi Arabia.
	United Arab Emirates.
	Indonesia.

By definition the total, oil-related, current account deficit of the consuming countries matches the total, oil-related, surplus of the producing countries. The total, oil-related, basic balances are also equal and opposite.

Factors taken into account in determining the 1970, 1975, 1980, and 1985 payments balances include:

1. Total energy consumption by country/region
2. Non-oil energy consumption
3. Oil production
4. Oil prices (f.o.b.)
5. Transportation costs and distribution patterns
6. Oil earnings (repatriated)
7. Transportation monies distribution
8. Import potentials of oil producing countries
9. Import patterns of oil producing countries
10. Capital flows to oil producing countries for oil exploration
11. Participation payments and oil ownership
12. Producing countries economic aid and investment patterns.

The above input requires thirteen separate matrices containing about 500 individual pieces of information for each of the four time periods. Additional discussion of the methodology is contained in the Appendix.

Assumptions

An "Illustrative Case" has been developed using a 3–4 percent per year inflation rate and current dollars. The major assumptions are:

U.S. energy consumption increases at 4 percent per year, down from 4.5 percent, reflecting partial success of conservation measures.

Operative nuclear capacity increases to 50 and 132 gigawatts in 1975 and 1980 providing 7 and 13 percent of U.S. energy requirements. (This assumption is consistent with the 1972 AEC projection contained in the May 4, 1973 Joint Committee on Atomic Energy report on the "National Energy Dilemma"). Domestic coal and gas production increase moderately—3 and 1.8 percent per year, respectively.

U.S. oil production declines to 10 million barrels per day in 1975 and increases to 11 million barrels per day in 1980 and 1985.

Persian Gulf crude costs (tax-paid cost plus average margin-f.o.b.) are $3.35, $5.20 and $8.15 per barrel in 1975, 1980, and 1985, representing a $1.00 per barrel increase over the currently agreed-to Persian Gulf crude prices in 1975 and a 10 percent per year increase from 1975 to 1985 for the tax-paid cost of the crude.

Other crude costs maintain current differentials. Sensitivities to $1 per barrel crude cost changes are shown (U.S. c.i.f. equivalents: $4.80, $6.25 and $9.15).

U.S. exports maintain their share (about 20 percent) of oil producers' imports, which increase 15–20 percent per year.

The U.S. capital market remains attractive for foreign investors, and the United States receives 25 percent of oil producers' long-term capital while importing less than 20 percent of their oil.

Additional descriptive information and the detailed assumptions for all the consuming and producing countries are in the Appendix.

RESULTS

The assumptions completely define the oil-related current account and basic payments balances and their elements over the payments situation that would exist but for the energy problem. The results for the given "Illustrative Case" are summarized in Tables 1–6. Appropriate sensitivities are summarized in Table 7. The consuming countries' position follows:

Illustrative case No. 1

[In billions of dollars]

Consuming countries	Current account balances			Basic payments balances		
	1970	1980	1985	1970	1980	1985
United States	2.4	−8.5	−10.0	2.3	−3.1	1.2
Western Europe	−4.0	−14.6	−23.2	−3.9	−9.0	−10.8
Japan	−.4	−12.9	−40.0	−.3	−9.1	−31.4
Canada	−.2	−1.3	−2.0	−0	−.9	−1.6
Other free world	−.2	−7.3	−20.1	.3	−.5	−5.3
Total	−2.5	−44.6	−95.4	−1.7	−22.6	−47.9

Although the changes in payments position are large, they are moderated by such factors as:

North Sea and other Western Europe oil production which is forecast to reach 4 million barrels per day by 1980.

A booming Japanese tanker construction industry that generates $4.4 billion in earnings by 1980, thus offsetting the cost of some oil imports.

Producers' Position

Saudi Arabia has the largest oil reserves and is projected to have the largest oil production—nearly 20 million barrels per day by 1980. This results in oil earnings of $36 billion (Table 3). Even though

Saudi imports are projected to rise at 20 percent per year, the excess revenues grow much faster.

The oil revenues of all producing countries increase from $14 billion in 1970 to $105 and $215 billion in 1980 (Table 4) and 1985. This results in excess revenues (after producing countries' merchandise imports, but before aid distribution or long-term investments) of $55 and $117 billion in 1980 and 1985.

Summaries of Accounts

The payments account summaries (Table 5) show reductions in the current accounts of the consuming countries while Saudi Arabia acquires over half the producing country surplus with the remainder being divided mostly among the United Arab Emirates, Iraq, and Kuwait.

The basic balance total is about half the current account total (Table 6). The assumptions about long-term capital investment favor the United States and reduce the U.S. basic balance deficit to $3 billion in 1980 whereas the western European and Japanese deficits are $9 billion.

Sensitivities

Sensitivities have been developed for many of the important variables. As shown in Table 7—

Annual increases of 4.5 percent (versus 4 percent) for U.S. total energy consumption increase 1980 oil imports by 2.4 million barrels per day and cause an additional $5 billion reduction of the U.S. current account. At 3.5 percent per year growth, there is $4.5 billion improvement.

If currently-agreed-to crude prices for 1975 are not changed and if Persian Gulf prices escalate at 10 percent per year from 1975 to 1980, the 1980 U.S. current account deficit is improved by $3.2 billion.

A $1 per barrel increase in crude costs would cause a $3.9 billion deterioration in the U.S. 1980 current account balance.

A 25 percent higher (lower) market share for U.S. exports would raise (lower) the U.S. 1980 current account balance by $2.5 billion.

CONCLUSIONS

The selected methodology enables realistic quantification—and projection—of the oil-related balance of payments accounts. Consideration of not only the oil movements but also the associated transportation, merchandise trade, capital, and economic aid accounts provides a meaningful perspective. Although uncertainties exist about energy demand, oil availability, oil prices, transportation rates, global economic conditions, and international capital accounts, these limitations do not preclude a systematic analysis of various energy assumptions.

TABLE 1.—*United States payments summary, illustrative case No. 1*

	1970	1975	1980	1985
Oil imports:				
Millions of barrels per day	$3. 1	8. 4	11. 6	12. 0
C.i.f. price per dollars per barrel	2. 33	4. 8	6. 25	[illegible]. 15
Annual cash flows (billions):				
Oil earnings	$2. 2	$3. 0	$4. 3	$3. 5
Transportation monies	. 8	1. 4	2. 0	2. 7
Exports to oil producers	1. 9	5. 0	10. 0	21. 0
Exports to others	. 1	. 8	1. 7	3. 3
Subtotal	5. 0	10. 2	18. 0	30. 5
Minus oil import (c.i.f.)	2. 6	14. 8	26. 5	40. 5
Current account	2. 4	—4. 6	—8. 5	—10. 0
Minus capital outflows	. 4	. 6	. 6	. 6
Plus participation payments	0	. 5	. 6	0
Plus capital inflows	. 3	2. 7	5. 4	11. 8
Basic balance	2. 3	—2. 0	-3. 1	1. 2
Memo items:				
Balances with no distribution:				
Current account	2. 1	—5. 4	—10. 2	—13. 3
Basic balance	1. 8	—5. 5	—10. 2	—13. 9
Balances with $1 per barrel higher price:				
Current account	2. 5	—7. 2	—11. 6	—12. 8
Basic balance	2. 1	—3. 6	—4. 5	. 5

TABLE 2.—*1980 consuming countries payments summary illustrative case No. 1*

	United States	Western Europe	Japan	Canada	Other	Total
Oil imports:						
Millions of barrels per day	11.6	20.6	11.5	1.8	9.2	54.7
C.i.f. price, dollar per barrel	6.25	6.35	5.83	6.24	5.83	6.13
Annual cash flow (in billions of dollars):						
Oil earnings	4.3	2.3	0	2.7	0	9.3
Transportation moneys	2.0	3.8	4.4	.1	.9	11.2
Exports to oil producers	10.0	23.1	5.4	0	8.6	47.1
Exports to others	1.7	4.1	1.6	0	2.8	10.2
Subtotal	18.0	33.3	11.4	2.8	12.3	77.8
Minus oil import cost (c.i.f.)	26.5	47.8	24.5	4.1	19.6	122.4
Current account	−8.5	−14.6	−12.9	−1.3	−7.3	−44.6
Minus capital outflows	.6	.5	.1	0	0	1.2
Plus participation payments	.6	.3	0	0	0	.9
Plus capital inflows	5.4	5.8	3.9	.4	6.8	22.3
Basic balance	−3.1	−9.0	−9.0	−.9	−.5	22.6
Memo items:						
Balances with no distribution:						
Current account	−10.2	−18.7	−14.5	−1.3	−10.1	−54.8
Basic balance	−10.2	−18.9	−14.6	−1.3	−10.1	−55.1
Balances with $1 per barrel higher price:						
Current account	−11.6	−20.1	−16.4	−1.4	−9.6	−59.1
Basic balance	−4.5	−12.8	−11.6	−1.0	−.9	−30.8

Table 3.—*Saudi Arabia payments summary illustrative case No. 1*

Oil production	1970	1975	1980	1985
Millions of barrels per day	3.8	10.0	19.6	27.0
Export price (dollars per barrel)	1.45	3.35	5.20	8.15
Annual cash flows (in billions of dollars):				
Oil exports	1.9	13.3	36.4	78.4
Plus transportation moneys	.2	.7	1.3	1.8
Minus oil earnings	.6	1.2	2.2	2.0
Minus imports	.7	2.0	5.0	10.5
Minus economic aid	.2	2.7	7.6	17.0
Current account	.7	8.1	22.9	50.8
Plus capital inflows	−.1	.1	.1	.1
Minus participating payments	.0	.2	.2	.0
Minus capital outflows	.4	4.8	13.7	30.5
Basic balance	.3	3.2	9.1	20.4
Memo items: Excess oil revenues	.8	10.7	30.4	67.9
Balances with no distribution:				
Current account	.9	10.8	30.5	67.8
Basic balance	.8	10.7	30.4	67.9
Balances with $1 per barrel higher price:				
Current account	.7	10.8	28.2	58.1
Basic balance	.3	4.3	11.2	23.3

TABLE 4.—*1980 producing countries payments summary illustrative case No. 1* [1]

Oil production	Venezuela	Algeria	Liberia	Nigeria	Iran	Iraq	Kuwait	Qatar	Saudi Arabia	Arab Emirates	Indonesia	Total
Millions of barrels per day	3.5	2.0	3.0	4.0	8.0	4.4	3.0	1.0	19.6	5.0	2.5	56.0
Export price (dollars per barrel)	5.90	6.10	6.10	5.95	5.20	5.20	5.20	5.20	5.20	5.20	6.36	------
Annual cash flows (in billions of dollars):												
Oil exports	6.3	4.2	7.0	8.5	14.0	8.0	5.3	2.0	36.4	9.0	4.3	105.0
Plus transportation moneys			.1	.2	.5	.3	.2	.1	1.3	.3	------	3.0
Minus oil earnings	.3	.1	.2	.4	.9	.5	.3	.1	2.3	.6	.4	6.0
Minus imports	6.0	4.2	4.4	7.0	10.8	2.5	1.7	.6	5.0	1.2	4.3	47.7
Minus economic aid			.6				.9	------	7.6	.8	------	9.9
Current account	0	—.1	2 2	1 3	2.6	5.3	2.7	1.1	22.9	6.7	0	44.0
Plus capital inflows		.1	------	.3	.1			.1	.1	.1	.1	1.0
Minus participation payments			.3	.1			.1	------	.2			1.0
Minus capital outflows			.7	------	1.0	1.9	1.6	.5	13.7	3.0	------	21.0
Basic balance	0	0	1.2	1.5	1.7	3.4	1.0	.6	9.1	3.8	.1	23.0
Memo items: Excess oil revenues			2.5	1.5	2.7	5.3	3.5	1.3	30.4	7.6	------	55.0
Balances with no distribution:												
Current account	0	—.1	2.8	1.3	2.6	5.3	3.6	1.1	30.5	7.4	0	53.9
Basic balance	0	0	2.5	1.5	2.7	5.3	3.5	1.2	30.4	7.5	.1	53.9
Balances with $1 per barrel higher price:												
Current account	0	.1	3.0	2.7	5.2	6.8	3.4	1.4	28.2	8.2	0	59.1
Basic balance	0	.1	1.8	2.9	3.5	4.4	1.3	.8	11.2	4.7	.1	30.8

[1] Venezuela, Algeria, Liberia, Nigeria, Iran, Iraq, Kuwait, Qatar, Saudi Arabia, United Arab Emirates, and Indonesia.

TABLE 5.—*Balances on current account summary, illustrative case No. 1*

[Billions of dollars]

	1970	1975	1980	1985
Consuming countries:				
United States	2.4	−4.6	−8.5	−10.0
West Europe	−4.0	−10.7	−14.6	−23.2
Japan	−.4	−4.5	−12.9	−40.0
Canada	−.2	−.5	−1.3	−2.0
Other free world	−.2	−2.1	−7.3	−20.1
Subtotal	−2.5	−22.3	−44.6	−95.4
Producing countries:				
Venezuela	0	.7	0	0
Algeria	0	.4	−.1	−.1
Libya	.9	2.6	2.2	.1
Nigeria	−.2	1.0	1.3	1.4
Iran	.1	3.7	2.6	.3
Iraq	.2	.1	5.3	21.8
Kuwait	.5	1.9	2.7	4.5
Qatar	.1	.9	1.1	1.3
Saudi Arabia	.7	8.1	22.9	50.8
United Arab Emirates	.2	2.8	6.7	15.2
Indonesia	0	0	0	0
Subtotal	2.5	22.3	44.6	95.4
Total	0	0	0	0

TABLE 6.—*Basic balances of payments summary, illustrative case No. 1*

[Billions of dollars]

	1970	1975	1980	1985
Consuming countries:				
United States	2.3	−2.0	−3.1	1.2
West Europe	−3.9	−8.1	−9.0	−10.8
Japan	−.3	−3.1	−9.1	−31.4
Canada	0	−.1	−.9	−1.6
Other free world	.3	.9	−.5	−5.3
Subtotal	−1.7	−12.4	−22.6	−47.9
Producing countries:				
Venezuela	.2	.7	−0	0
Algeria	0	.2	0	0
Libya	.7	1.6	1.2	.1
Nigeria	0	1.2	1.5	1.7
Iran	0	2.5	1.7	.2
Iraq	.1	.1	3.4	14.2
Kuwait	.1	.8	1	1.8
Qatar	.1	.5	.6	.7
Saudi Arabia	.3	3.2	9.1	20.4
United Arab Emirates	.1	1.6	3.8	8.7
Indonesia	0	0	.1	.1
Subtotal	1.7	12.4	22.6	47.9
Total	0	0	0	0

Table 7.—*Sensitivity of assumptions 1980 and 1985 U.S. payments balances*

[Billions of dollars]

Case description	Current account 1980	Current account 1985	Basic balance 1980	Basic balance 1985
Illustrative case No. 1	−8.5	−10.0	−3.1	1.2
Changes in illustrative case for:				
1. U.S. energy consumption increases at 4.5 percent per year instead of 4 percent (2,400,000 and 4,400,000 barrels per day more imports)	−5.0	−13.8	−4.6	−12.5
2. U.S. energy consumption increases at 3.5 percent per year instead of 4 percent (2,200,000 and 4,200,000 barrels per day less imports)	+4.5	+13.2	+4.1	+11.9
3. Already agreed to price changes hold through 1975 ($1 per barrel lower 1975 prices) and and 10 percent per year increase 1975 to 1985	+3.9	+3.9	+1.4	−.7
4. $1 per barrel higher prices	−3.1	−2.8	−1.4	−.2
5. U.S. increases market share of crude producers by 25 percent	+2.5	+5.2	+2.5	+5.2

Appendix

Basic Formula

The computer program calculates the oil-related current account balances and basic payments balances for the oil consuming and producing countries according to the following formulas, which are additive both vertically and horizontally.

Consuming countries	+Producing countries	=Total
	Oil exports	Oil exports.
Transportation moneys	+Transportation moneys.	Trans cost.
+Oil earnings	−Oil earnings	Zero.
+Merchandise exports	−Merchandise imports.	Zero.
+Other exports	−Economic aid	Zero.
−Oil import cost		−Oil import cost.
Current account	+Current account	Zero.
−Oil exploration capital outflows.	+Oil exploration capital inflows.	Zero.
+Participation payments.	−Participation payments.	Zero.
Basic Balance	+Basic balance	Zero.

By definition, the total current account deficit of the consuming countries matches the total surplus of the producing countries. The total basic balances are also equal and opposite. A brief discussion of each of the input items follows. The quantitative assumptions are in Attachments 1–12.

Oil Exports

Oil exports represent the value received for the oil in the producing countries. Allowance is made for domestic oil consumption. Included in current dollars are the tax-paid oil cost and the apparent margin. The tax-paid costs for 1970 are a matter of record. For 1975 the Persian Gulf and African oil costs include the escalations agreed to in the Tehran, Tripoli, and Geneva meetings, full adjustment for the recent devaluation, plus $1.00 per barrel to reflect further adjustments. For 1980 and 1985, tax-paid costs are escalated by 10 percent per year from 1975. Apparent margins are held constant, and producing countries are assumed to share the apparent margin as they assume oil ownership. For Venezuela, Indonesia and Canada, constant differentials are based on quality and transportation factors.

Oil Distribution Patterns

Oil is assumed to be imported from traditional country suppliers to the extent that availability considerations permit. Canada exports to the United States, and Canada imports from Western Hemisphere sources—in this case from Venezuela. African crudes go mostly to

Europe, but some Nigerian and Libyan crudes do go to the United States. Indonesian crudes go mostly to Japan, but some also go to the United States. The Middle East supplies crude shortfalls.

Transportation Costs

Transportation costs are based on a viable tanker industry. Long-term rates are consistent with an adequate investment return on very large crude carriers. Subsequent distribution of transportation monies is based on fueling tankers at their loading points, current ownership patterns, and reinvestment of financial flows in new tanker construction. Japan's resulting financial flow on transportation monies is indicative of current tanker building activity, and her 1970 inflows match her income on 1970 tanker deliveries.

Oil Earnings

Oil earnings represent the apparent margin earned by the owners of the producing companies. Oil earnings are distributed to the consuming countries according to ownership. Although the margin per barrel produced is assumed constant, the producing companies' unit earnings fall as participation begins. Presumably, downstream operations will become more profitable. The somewhat optimistic assumption is made that the producing countries will require assistance in selling their oil in 1975 and 1980 and will pay the producing companies one-half of the apparent margin for this service.

Merchandise Exports

Oil producers can use their oil-related receipts for merchandise (consumer, capital, and military goods) imports, for economic aid, for long-term investment, or for building their financial reserves. The populations and/or needs of many countries are large enough so that merchandise imports will require nearly all the foreign exchange. These countries are: Venezuela, Algeria, Libya, Nigeria, Iran and Indonesia. However, the other five countries—Iraq, Kuwait, Qatar, Saudi Arabia, and United Arab Emirates—have spending limitations. Their populations are small, and their revenues are large. Procedural problems, delivery times, and a cautious approach will slow expenditures. Accordingly, maximum import potentials have been estimated for these countries based on their expanding merchandise imports at 15–20 percent per year.

One simplifying assumption is that merchandise exports equal merchandise imports. To the extent that merchandise exports are carried in foreign ships, some consuming countries' (mainly the United States) balances will be slightly overstated, and others' will be understated. This second order factor is believed to be offset by the assumption that no U.S. exports to Canada are associated with U.S. imports of Canadian crude. Although Canada is a net crude importer and Canada has had and should continue to have trade and payments surpluses, about \$100–200 million per year of U.S. exports probably are associated with Canadian oil activities.

Aid Assistance

"Other exports" represent those exports to other developing countries bought with economic aid from Libya, Kuwait, Qatar, Saudi Arabia, and United Arab Emirates. These latter countries are assumed to use 10–25 percent of their excess revenues for economic aid. A sub-case is developed for no economic aid. The program contains no provision for other secondary spending of oil monies. Rather the assumption is made that Japanese, Western Europe and Canadian imports will be independent of receipts from their exports. If this secondary effect does come into play, presumably the changes in the rest of the world's trade patterns would be similar to the changes in the oil producers' patterns as all buyers attempt to get the best bargains. This would increase trade and payments swings.

Capital for Oil Exploration and Development

Long-term capital flows include oil exploration and development capital flows from the consuming countries to the producing countries Such capital flows supplement the internal funds generation from depreciation and amortization. At 5¢ per barrel, the funds generated from depreciation and amortization will total about \$1 billion per year by 1980. Both consuming countries and producing countries are projected to add about the same amount for oil exploration and development. Sensitivities have been developed for no flows of consuming country capital to the producing countries. In any event a \$1 billion per year capital outflow for oil exploration and development is small relative to the excess revenues which are \$55 and \$117 billion per year in 1980 and 1985.

Participation Payments

Participation payments for acquiring 51 percent of their oil production have been agreed to by Kuwait, Qatar, Saudi Arabia, and the United Arab Emirates. A similar arrangement is envisioned for Nigeria. Different arrangements appear likely in the other oil producing countries. These payments are included in the long-term capital flows. Just as with the oil exploration monies, the participation payments are small relative to excess oil revenues.

Producers' Long-Term Capital Investments

The assumptions about long-term capital investments by the oil producers are critical to the analysis. In this "illustrative case," where oil prices increase 10 percent per year, excess funds are generated

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at phenomenal rates—$55 billion in 1980 and $117 billion in 1985. About 20 percent of these funds are assumed to be used for economic assistance, and the rest are available for long-term investments or for increasing financial reserves.

Illustrative Case Assumptions

A methodology summary showing the formulas is on the next page. The assumptions—or input—for the "Illustrative Case" are summarized in Attachments 1–12.

ENERGY BALANCE OF PAYMENTS

Methodology summary formulas

Item	*Formula* [1]
I. Total oil consumption	$I=1-2$.
II. Oil imports	$II=I-3$.[2]
III. Oil exports	$III=3-I$.[2]
IV. Oil import cost	$IV=II(4+5)$.
V. Oil investment earnings	$V=(3)(6)$.
VI. Transportation earnings	$VI=II(5)(7)$.
VII. Imports of oil producers by source.	$VII \leq (9)(8)$ or $^{9}(III(4)+VI-V+10-11$.
VIII. Current account balances:	
VIIIc Consuming countries	$VIIIc=V+VI+VII-IV+12_c$.
VIIIp Producing countries	$VIIIp=(III)\ (4)+VI-V-VII-12_c$.
IX. Excess oil revenues	$IX=(VIIIp+10-11)$.
X. Basic balances:	
Xc Consuming countries	$Xc=(VIIIc-10+11+12_b)$.
Xp Producing countries	$Xp=(VIIIp+10-11-12_b)$.

[1] Arabic numbers refer to input attachments which follow.

[2] Except for Canada.

Methodology summary list of attachments

Attachment and item	Units	Source
1. Energy consumption by country.	Million barrels per day.	National Petroleum Council, Statistics, OECD, Interior.
2. Nonoil energy consumption.	do	Do.
3. Domestic oil production.	do	Do.
4. Oil export prices (f.o.b.)	Dollar per barrel	Interior.
5. Transportation costs	do	Estimated.
6. Oil earnings	do	Do.
7. Distribution of transportation monies.	do	Do.
8. Import potentials of oil exporters.	Dollars—Billions	Do.
9. Import patterns of oil exporters.	Percent	OECD and Commerce.
10. Capital flows for oil exploration.	Dollars—Billions	Estimated.
11. Participation payments	do	Do.
12. Capital flows for excess oil revenues.	do	Do.
13. Methodology Summary Formulas.		

ATTACHMENT 1

Total energy consumption illustrative case No. 1

Country	Per capita consumption (barrels per day) 1970	Per capita consumption (barrels per day) 1985	Percent per year growth rate, 1970–85	Total consumption (million barrels per day equivalent) 1970	1975	1980	1985
United States	58.5	89.7	4	32.8	39.8	48.5	59.0
Western Europe	24.5	45.3	5	22.4	28.6	36.5	46.5
Japan	20.5	72.7	10	5.8	9.3	15.0	24.2
Canada	46.0	86.0	6	2.7	3.6	4.9	6.5
Other free world	4.1	6.5	6	11.3	15.1	20.3	27.2
Subtotal	16.5	26.0	----------	75.0	96.4	125.2	163.4
Venezuela	10.5	25.9	10	.3	.5	.81	1.35
Algeria	1.5	3.6	10	.06	.1	.16	.25
Libya	5.6	13.8	10	.03	.05	.08	.13
Nigeria	.2	.8	10	.04	.06	.10	.17
Iran	4.7	12.8	10	.37	.62	1.0	1.51
Iraq	3.5	9.0	10	.09	.15	.23	.38
Kuwait	81.6	110.0	5	.17	.25	.30	.35
Qatar	----------	----------	----------	----------	----------	----------	----------
Saudi Arabia	9.4	26.0	10	.2	.32	.53	.84
United Arab Emirates	.1	.5	10	.14	.23	.36	.58
Indonesia	.6	1.6	10	.2	.32	.53	.84
Subtotal	2.3	6.1	----------	1.6	2.6	4.1	6.4
Total	14.6	23.2	----------	76.6	99.0	129.3	169.8

ATTACHMENT 2

Nonoil energy consumption, illustrative case No. 1

[Million barrels per day equivalent]

	1970	1975	1980	1985
United States:				
Coal	6.3	7.0	8.0	10.0
Gas	10.7	11.5	12.0	14.0
Water	1.3	1.4	1.5	1.6
Nuclear	.1	1.5	3.9	8.0
Other			.5	2.4
Subtotal	18.4	21.4	25.9	36.0
Western Europe:				
Coal	6.1	5.5	5.0	4.0
Gas	1.4	2.5	4.0	6.0
Water	1.8	2.0	2.5	3.0
Nuclear	.3	.7	1.6	3.0
Other	.1	.1	.3	.5
Subtotal	9.7	10.8	13.4	16.5
Japan:				
Coal	1.2	1.6	2.1	3.0
Gas	.1	.2	.3	.4
Water	.4	.5	.6	.7
Nuclear		.2	.5	1.0
Other				
Subtotal	1.7	2.5	3.5	5.1
Canada:				
Coal	.3	.4	.5	.6
Gas	.6	.8	1.0	1.3
Water	.3	.3	.4	.5
Nuclear		.1	.2	.3
Other				
Subtotal	1.2	1.6	2.1	2.7
Oil exporter: Gas [1]	.5	.8	1.3	2.1
Other free world:				
Coal	3.6	3.6	3.6	3.6
Gas	.4	.6	.8	1.0
Water	1.0	1.2	1.4	1.6
Nuclear			.3	.6
Other				
Subtotal	5.0	5.4	6.1	6.8

Footnote at end of table.

ATTACHMENT 2—Continued

Nonoil energy consumption, illustrative case No. 1—Con.

[Million barrels per day equivalent]

	1970	1975	1980	1985
Free world:				
Coal	17.5	18.1	19.2	21.2
Gas	13.7	16.4	19.4	24.8
Water	4.8	5.4	6.4	7.4
Nuclear	.4	2.5	6.5	12.9
Other	.1	.1	.8	2.9
Subtotal	36.5	42.5	52.3	69.2

[1] See attachment 2A.

ATTACHMENT 2A

Gas usage by exporter countries, illustrative case No. 1

[Million barrels per day oil equivalent]

	1970	1975	1980	1985
Venezuela	0.11	0.18	0.28	0.45
Algeria	.02	.03	.05	.08
Libya	.01	.02	.03	.04
Nigeria	.01	.02	.03	.04
Iran	.10	.16	.26	.42
Iraq	.02	.03	.05	.08
Kuwait	.05	.06	.13	.20
Qatar				
Saudi Arabia	.05	.08	.13	.22
United Arab Emirates	.05	.08	.13	.22
Indonesia	.08	.14	.21	.35
Total	.50	.8	1.3	2.1

Oil production, illustrative case No. 1

[Million barrels per day]

	1970	1975	1980	1985
Exporting countries:				
Venezuela	3.8	3.5	3.5	3.5
Algeria	1.0	1.5	2.0	2.5
Libya	3.3	3.0	3.0	3.0
Nigeria	1.1	2.5	4.0	6.0
Iran	3.8	6.6	8.0	10.0
Iraq	1.6	2.9	4.4	9.0
Kuwait	3.0	3.0	3.0	3.0
Qatar	.4	1.0	1.0	1.0
Saudi Arabia	3.8	10.0	19.6	27.0
United Arab Emirates	1.3	3.0	5.0	7.0
Indonesia	.9	1.5	2.5	3.6
Subtotal exporters	24.0	38.5	56.0	75.6
Consuming countries:				
United States	11.3	10.0	11.0	11.0
West Europe [1]	.3	2.0	2.5	4.0
Japan				
Canada	1.3	2.0	2.5	3.5
Other free world	3.2	4.0	5.0	6.5
Subtotal	16.1	18.0	21.0	25.0
Total	40.1	56.5	77.0	100.6

[1] Includes Soviet imports.

ATTACHMENT 4

Oil export prices, illustrative case No. 1

[Dollars per barrel f.o.b.]

	1970 [1]	1975 [2]	1980 [3]	1985 [3]
Venezuela	1.90	4.05	5.90	8.85
Algeria	2.10	4.27	6.10	9.07
Libya	1.78	4.27	6.10	9.07
Nigeria	1.74	4.10	5.95	8.90
All Persian Gulf	1.45	3.35	5.20	8.15
Indonesia	1.60	4.51	6.36	9.31
Canada	2.80	5.00	6.66	9.70

[1] 1970 basis—1970 tax-paid cost plus 1970 apparent margin.

[2] 1975 basis—Tax-paid cost per various agreements plus 10 percent for devaluation plus constant 1970 apparent margin for Mideast and African crudes plus $1 per barrel. Venezuela, Indonesia and Canadian crudes reflect quality and transportation differentials.

[3] 1980–85 basis—1975 tax-paid cost increased by 10 percent per year for All Persian Gulf crudes; margins and crude differentials remain constant for other crudes.

ATTACHMENT 5

Transportation costs and distribution patterns, illustrative case No. 1

Destination	United States	West Europe	Japan	Canada	Other
Transportation costs, per barrel (Percent of world scale rate):					
Venezuela	0.24 (90)			0.40 (110)	0.26 (100)
Nigeria	.62 (100)	0.57 (100)			
Mediterranean	.57 (100)	.39 (100)			
Persian Gulf	1.13 (85)	1.07 (85)	0.60 (85)		.62 (100)
Indonesia	.82 (90)		.38 (90)		.38 (90)
Distribution patterns, percent of oil exports:					
Venezuela	[b] 70			([a])	[a] 30
Algeria		[a] 100			
Libya	[c] 10	[b] 90			
Nigeria	[d] 20	[c] 80			
Persian Gulf	(*f)	(*d)	(*b)		(*e)
Indonesia	[e] 20		[a] 70		[b] 10
Canada	[a] 100				

TRANSPORTATION NOTES

(1) World scale rates have been increased to reflect the 1973 dollar devaluation.
(2) Rates should allow adequate return for new tankers.
(3) Suez remains closed.

DISTRIBUTION NOTES

(1) Lower case letters indicate sequential patterns for oil imports.
(2) Venezuela supplies Canada before supplying United States and "other."
(3) Star indicates that Persian Gulf supplies any shortfall.

Attachment 6

Oil earnings to consuming countries illustrative case No. 1

	Percent distribution		Total earnings (cents per barrel produced)			
	United States	Western Europe	1970 [1] [2]	[3] 1975	[3] 1980	[4] 1985
Venezuela	80	20	40	40	36	0
Algeria		100	17	17	10	10
Libya	90	10	30	22	19	8
Nigeria	20	80	40	35	32	20
Iran	40	60	40	35	32	20
Iraq	20	80	40	35	32	20
Kuwait	50	50	40	35	32	20
Qater		100	40	35	32	20
Saudi Arabia	100		40	35	32	20
United Arab Emirates	20	80	40	35	32	20
Indonesia	100		10	10	10	10
Canada	100		50	50	50	50

[1] 1970 oil earnings or apparent margin based on above earnings and attachment 3 production:

[In millions of dollars]

	Total	United States	Survey of current business	Comments on the survey
Venezuela	555	445	417	Includes all Latin America.
Africa	584	358	600	Tanker earnings.
Mid East	2, 060	1, 170	1, 178	Good check.
Canada	237	237	342	Gas and refinery earnings.
Total	3, 469	2, 243	2, 537	

[2] 1970 basis: Distribution of 1970 apparent margin per ownership.

[3] 1975 and 1980 basis: Same margin as 1970 on oil companies' barrel and 50 percent of same margin on producing countries' barrels per attachment 11.

[4] 1985 basis: No oil company revenue on producing countries' barrels.

NOTE.—Other ranges to be investigated include constant earnings and increasing earnings.

ATTACHMENT 7

Distribution of transportation moneys, illustrative case No. 2

[Percent]

Item	Total	Oil exporting countries	United States	Western Europe	Japan	Others
Fuel	15	15				
Crews	5	1	1	1	1	1
Financing	40	5	5	10	20	
Profit and taxes	20	2	5	5	4	4
Other	20		3	10	5	2
Total	100	23	14	26	30	7

NOTE: These approximate distributions are based on: (1) Largely foreign construction and foreign financing of new tankers; (2) foreign fueling; (3) European and Japanese maintenance, and largely European insurance.

ATTACHMENT 8

Import potentials of oil exporting countries illustrative case No. 1

Oil producers	Actual imports (in billions of dollars) 1966	1970	Projected potential imports (in billions) 1975	1980	1985	Percent per year growth rate (1970–85)
Venezuela	1.5	2.0	4.0	8.0	16.0	15
Algeria	.6	1.2	1.4	4.8	9.6	15
Libya	.4	.6	1.5	3.7	9.5	20
Nigeria	.7	1.1	2.8	7.0	17.5	20
Iran	.9	1.7	4.3	10.8	27.0	20
Iraq	.5	.5	1.0	2.0	4.0	15
Kuwait	.5	.7	1.4	2.8	5.6	15
Qatar	.0	.1	.3	.6	1.5	20
Saudi Arabi	.6	.7	2.0	5.0	10.5	20
United Arab Emirates	.2	.3	.6	1.2	2.4	15
Indonesia	.5	.9	2.3	5.7	14.0	20
Canada			0	0	0	

ATTACHMENT 9

Import patterns of oil exporting countries, illustrative case No. 1

[Percent share of total import market]

Base case (1970 pattern)	Import source			
	United States	Western Europe	Japan	Other
Venezuela	40	29	7	24
Algeria	7	78	2	13
Libya	21	64	6	9
Nigeria	13	54	7	26
Iran	22	52	12	14
Iraq	5	44	4	47
Kuwait [1]	18	37	18	27
Qatar	17	58	14	11
Saudi Arabia [1]	25	44	13	18
United Arab Emirates	17	58	14	11
Indonesia [1]	30	29	37	4

[1] 1970 U.S. share adjusted to be more consistent with historical pattern.

ATTACHMENT 10

Capital flows for oil exploration—Illustrative Case No. 1

	Percent distribution from consuming country sources			Total capital from outside (millions of dollars)				
	United States	West Europe	Japan	1970	United States	1975	1980	1985
Venezuela	80	20	----------	200	160	----------	----------	----------
Algeria	----------	100	----------	50	----------	100	100	100
Libya	90	10	----------	100	90	----------	----------	----------
Nigeria	20	80	----------	200	40	300	300	300
Iran	40	60	----------	−100	−40	100	100	100
Iraq	20	80	----------	----------	----------	----------	----------	----------
Kuwait	50	50	----------	−100	−50	----------	----------	----------
Qatar	----------	50	50	60	----------	50	50	----------
Saudi Arabia	80	10	10	−100	−80	100	100	100
United Arab Emirates	20	60	20	50	10	100	100	100
Indonesia	80	----------	20	25	20	50	50	50
Canada	100	----------	----------	200	200	400	400	400
Total				585	350	1,200	1,200	1,150

NOTE.—These capital flows are for exploration and development investments that increase foreign capitalization; i.e., funds over and above depreciation or amortization.

ATTACHMENT 11

Participation payments and oil ownership, illustrative case No. 1

	1975	1980	1985
Estimated participation payments (millions of dollars):			
Venezuela			
Algeria			
Libya	300	300	
Nigeria	100	100	
Iran			
Iraq			
Kuwait	57	67	
Qatar	27	33	
Saudi Arabia	193	220	
United Arab Emirates	88	100	
Indonesia			
Total	765	720	
Estimated producing country ownership (percent):			
Venezuela	0	10	100
Algeria	77	90	90
Libya	51	75	75
Nigeria	25	40	51
Iran	10	40	51
Iraq	100	100	100
Kuwait	25	40	51
Qatar	25	40	51
Saudi Arabia	25	40	51
United Arab Emirates	25	40	51
Indonesia	100	100	100

Note.—Participation payments are current as of February 1973 (Petroleum Press Service) and include adjustment for Feb. 12 devaluation. Nigeria and Libya are assumed to make indicated participation agreements. Iran and Venezuela are assumed to take partial and total ownership at end of current concessions. Iraq nationalization assumed to have no net exchange of funds, but a lower purchase price that allows continued profits to former owners.

ATTACHMENT 12

Disposition of excess oil revenues, illustrative case No. 1

[In percent]

Producing country	Current account items including aid to foreign countries[1]				Long-term capital investment[2]				Reserves and short-term investment
	United States	Western Europe	Japan	Other	United States	Western Europe	Japan	Other	
Venezuela									100
Algeria					10	40			50
Libya	5	10	3	7	5	5		15	50
Nigeria									100
Iran					15	15		5	65
Iraq					10	15		10	65
Kuwait	4	10	4	7	15	15		15	30
Qatar	2	5	2	3	10	10	10	8	50
Saudi Arabia	4	10	4	7	10	10	10	15	30
United Arab Emirates	2	5	2	3	10	10	10	8	50
Indonesia									100
Canada									100

[1] These items are 12c in attachment 13.

[2] These items are 12b in attachment 13.

Appendix D

The Natural Gas Shortage and the Regulation of Natural Gas Producers—Reprinted From the Harvard Law Review

ARTICLE

THE NATURAL GAS SHORTAGE AND THE REGULATION OF NATURAL GAS PRODUCERS

by

STEPHEN BREYER
PAUL W. MacAVOY

Reprinted From
Harvard Law Review
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THE NATURAL GAS SHORTAGE AND THE REGULATION OF NATURAL GAS PRODUCERS †

Stephen Breyer * *and Paul W. MacAvoy* **

In an attack upon the current natural gas shortage, President Nixon has recently urged an end to much of the Federal Power Commission's regulation of the price of natural gas at the wellhead. From the perspectives of both the lawyer and the economist, Professors Breyer and MacAvoy lend support to a policy change in this direction. They show that regulation of gas wellhead prices raises problems substantially different from the regulation of traditional public utilities. They argue that the policies the Commission has pursued were almost inevitably bound to result in wellhead prices below the market level that would call forth supplies sufficient to meet demand, and, through econometric analysis, they demonstrate the extent to which the Commission's pricing practices produced the shortage. While the Commission's policies were aimed at helping home consumers, data gathered by the authors indicate that regulation has brought about precisely the opposite result. The Commission's experience may well cast light on the wisdom of adopting regulatory techniques to redistribute income when serious economic efficiency losses are likely to arise.

IN 1954, somewhat to the Federal Power Commission's (FPC's) surprise, the Supreme Court held in *Phillips Petroleum Company v. Wisconsin*[1] that the Commission had authority to regulate the prices at which natural gas field producers sold gas to interstate pipeline companies.[2] In the past decade, the FPC has devoted much of its energy and about 30 percent of its budget to such regulation [3] and has been remarkably effective in holding down producers' selling prices.[4] Whether this regulation has benefited the nation or even the consumers it was designed to help, however, is another matter. It is the purpose of this article to evaluate the results of the Court's decision [5] and the FPC's

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† This article is adapted from a forthcoming book by the authors on energy regulation by the Federal Power Commission (FPC), funded and soon to be published by the Brookings Institution.

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[1] 347 U.S. 672 (1954).

[2] Prior to this decision, FPC regulation of the natural gas industry extended only to the regulation of prices for the transporting of gas across state lines for the purposes of resale.

[3] MacAvoy, *The Effectiveness of the Federal Power Commission*, 1 BELL J. OF ECON. & MANAGEMENT SCI. 271, 303 n.22 (1970).

[4] *See* Table I, p. 975 *infra*.

[5] Although in debates over the wisdom of FPC regulatory policy the *Phillips* decision itself is often violently attacked, the Court's logic in that case was not

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ensuing regulatory effort. Such an evaluation is especially timely because President Nixon has recently proposed the discontinuance of much wellhead price regulation.[6]

Natural gas now supplies more than a third of America's energy needs[7] and exists in the ground in sufficient quantities to forestall any danger in the foreseeable future of its extinction as a natural resource.[8] Nevertheless, there is now, in the early

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wholly unreasonable, though neither was it totally satisfying. Whether the FPC should have jurisdiction over producer prices is not clear from the statutory language of the Natural Gas Act. 15 U.S.C. §§ 717–717w (1970). The Act states that

> [t]he provisions of this chapter shall apply to . . . the sale in interstate commerce of natural gas for resale . . . but shall not apply to . . . the production or gathering of natural gas.

15 U.S.C. § 717b (1970). To be sure, a field producer's sale to an interstate pipeline is "a sale in interstate commerce for resale." But whether the exemption for "production and gathering" applies to the physical production and gathering operations only *or* to those operations and also the *sale* of what is gathered, is not clear.

While the legislative history of the Act has little to say about producer regulation, what is said seems to support the Court's decision. The House of Representatives Committee Report states that the words "production or gathering" are "not actually necessary, as the matters specified therein could not be said fairly to be covered by the language affirmatively stating the jurisdiction of the Commission . . . ." H.R. REP. No. 709, 75th Cong., 1st Sess. 3 (1937). *See generally* Note, *Legislative History of the Natural Gas Act*, 44 GEO. L.J. 695 (1956). This statement suggests that Congress did not mean to exempt from regulation sales by producers to pipelines, for such sales surely could be said "to be covered by the language affirmatively stating the jurisdiction of the Commission" over sales for resale in interstate commerce. Moreover, although the FPC consistently refused before 1954 to regulate producers, at their urging Congress passed a bill granting a clear producer exemption — a bill that President Truman vetoed. Thus the producers, the Congress, and the President arguably acted as if the producers might be regulated by existing law. For an excellent discussion of this point, and of producer price regulation generally, see Kitch, *Regulation in the Field Market for Natural Gas by the Federal Power Commission*, 11 J. LAW & ECON. 243, 254–55 (1968).

Despite this support for the Court's position, however, the *Phillips* decision can be criticized. The Court did not examine, more than superficially, the economic purposes that producer regulation might serve. Without such an examination, the Court could not tell what sense producer regulation made economically or whether it was consistent with a general regulatory policy which provides for the supervision of the prices of monopoly (or oligopoly) gas transmission companies and of monopoly retail gas distributing companies. If producer regulation is not consistent with this general regulatory policy, then to assume a congressional intent to regulate producers in the face of ambiguous statutory language and a near-silent legislative history was not warranted, and produced bad law. To what extent the Court in 1954 could have been aware of the facts and arguments concerning the economic rationale for regulation, we leave to the reader to judge.

[6] N.Y. Times, April 19, 1973, at 1, col. 1; *see* note 134 *infra*.

[7] Southern Louisiana Area Rate Cases v. FPC, 428 F.2d 407, 418 n.10 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970).

[8] Recent estimates place potential reserves in the U.S. at 1,227 trillion cubic feet in addition to the present proven reserve inventory of 275.1 trillion cubic

1970's, no lack of evidence that the United States is in the throes of a serious natural gas shortage.[9] This article will show that that shortage is a direct result of FPC regulation of producers' prices and that the shortage has been disproportionately borne by home consumers. Moreover, the article will show that the losses arising from the shortage have been so great that they cannot rationally be worth the pursuit of whatever valid purposes might be served by lower user prices. To explain how this state of affairs has come about, we shall explore the objectives of producer price regulation and the methods used by the FPC to achieve them. We shall then describe the results that FPC regulation has brought about. We shall conclude that the harms regulation has produced so far outweigh the benefits of lower price that gas price regulation at the wellhead should be substantially abandoned.

The article has another, more general purpose. It is becoming increasingly common to think of price and profit regulation as designed to achieve not simply economic efficiency, but also a more nearly equal income distribution.[10] Of course, these two objectives often peacefully coexist: to limit a monopolist's prices increases output and also redistributes income, probably towards equality. Sometimes, however, these goals directly conflict: to hold prices below the competitive level may lead to a more equal income distribution, but it may also wastefully create excess demand. When faced with such a conflict, some may argue that the "income distribution" objective should be favored over "economic efficiency."

This seemingly has been the view of the FPC in regulating producer gas prices. We shall argue, however, that the FPC's efforts to hold prices down for the residential gas consumer have not helped him; in fact, they have simply led to a gas shortage that has hurt him more. If redistribution of income is a proper regulatory goal, the FPC has failed to achieve it. Our discussion of the reasons for this failure shows the extreme practical difficulties that face an agency trying to use prices to pursue such a goal. And these practical difficulties should explain our grave doubts about whether generally such a goal is proper when serious efficiency losses are at stake.

feet. FEDERAL POWER COMMISSION, 1970 ANNUAL REPORT 52 (1971). Of course, much of the potential reserves exists in high-risk, high-cost areas. *Id.* at 52. But these figures for potential resources do not include the possibility of expansion by way of technological advances in obtaining gas from coal and in stimulating low-productivity gas reservoirs through the use of nuclear power. *Id.* at 53–54.

[9] *See* pp. 965–66.

[10] *See, e.g.*, Posner, *Taxation by Regulation*, 2 BELL J. OF ECON. & MANAGEMENT SCI. 22 (1971).

Before turning to an assessment of FPC regulation of gas producer prices, a brief description of the field market for natural gas may be helpful.[11] Most producers search for gas by drilling wells on leased land. The gas is brought to the surface where it is sometimes "refined," producing liquid byproducts which can be sold separately. The gas itself may be sold directly to intrastate users and distributors, but most is sold to interstate pipeline companies.[12] These transmission companies transport the gas from the field and resell it either directly to industrial users or to distributing companies, which in turn resell to industry or to home consumers. Before World War II, gas was discovered and exploited mainly as a byproduct of the search for oil [13] and was sold at prices that had only to pay the ascertainable separate costs of gas production.[14] However, the growth of pipelines capable of bringing gas from fields in Texas, Oklahoma, and Louisiana to coastal markets increased the demand for gas to the point where today less than 25 percent of all gas produced comes from oil wells; most comes from wells that produce only gas, found in the search for gas itself.[15]

I. THE OBJECTIVES OF PRODUCER PRICE REGULATION

In order to evaluate the FPC's policy of regulating natural gas prices at the wellhead, it is necessary first to determine what the objectives of such a policy could be. There are two conceptually distinct purposes that regulation of gas producers might serve: reduction of market power and redistribution of income. That neither the Commission nor the courts have made much effort to distinguish between these purposes makes the task of evaluating regulation more difficult.

A. Control of Market Power

Control of market power constitutes the traditional economic rationale for regulation. Stated in simple and direct fashion, where one firm, or possibly a small group of firms, produces the entire output of an industry, the industry's output tends to be

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[11] For general background on the production of natural gas, see J. KORNFELD, NATURAL GAS ECONOMICS (1950); S. PIRSON, OIL RESERVOIR ENGINEERING (1959); L. UREN, PETROLEUM PRODUCTION ENGINEERING (1934).

[12] *See* Table II, p. 978 *infra*.

[13] *See* P. MACAVOY, PRICE FORMATION IN NATURAL GAS FIELDS chs. 5–7 (1962) [hereinafter cited as PRICE FORMATION].

[14] *See* pp. 954–57 *infra*.

[15] *See* C. HAWKINS, THE FIELD PRICE REGULATION OF NATURAL GAS 221 (1969) [hereinafter cited as HAWKINS].

less — and profits more — than that which would be provided by competitive suppliers. This is so because the monopoly (or oligopoly) firm will restrict its output in order to increase the market price of its products — so as to add to net revenues via a higher price-cost margin more than is lost by restricting output. The government may seek to reduce prices and increase output by attacking market power directly through antitrust actions designed to create competition in the industry. If, however, such a policy is too costly because economies of scale make production by more firms less efficient, the government may try to combat market power by regulation of industry prices. In either instance, a major motivating force of the government's initiatives is to achieve efficient resource allocation; the objectives in setting lower prices at the margin are to reduce profits and to expand output, allowing buyers willing to pay the cost of extra units of goods to receive those goods.

Such a market power theory was advanced by supporters of gas producer regulation. They asserted that gas production was concentrated in the hands of a few producing companies — so few that the largest producers could raise the price of gas to the interstate pipelines above the level that competition would otherwise dictate.[16] Unless market power at the wellhead was checked, pipeline regulation would not be wholly effective in protecting consumers from noncompetitive prices; consumers would still have to pay monopoly wellhead prices for gas, since these prices would be passed through to retail distributors as "costs" of the pipelines. In the words of the Supreme Court,[17]

> the rates charged [by producers] may have a direct and substantial effect on the price paid by the ultimate consumers. Protection of consumers against exploitation at the hands of natural-gas companies was the primary aim of the Natural Gas Act.

Thus, the argument ran, the FPC should determine the price at which gas would be sold under competitive production conditions and should forbid producers to sell at higher prices.

However, while the question of market power played an important role in the early history of the debate over producer regulation, it has become less significant in more recent years as accumulated evidence has created a strong presumption that gas producers do not possess monopolistic or oligopolistic market

[16] *See, e.g.*, Douglas, *The Case for the Consumer of Natural Gas*, 44 GEO. L.J. 566, 589 (1955) ("Competition is limited by the domination of supply and reserves by a very few major companies . . . .").

[17] Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672, 685 (1954).

power. As the U.S. Court of Appeals for the Fifth Circuit has recently said,[18] "[T]here seems to be general agreement that the [field] market is at least structurally competitive." Federal Power Commission statistics show that in the early 1960's the largest gas producer accounted for less than 10 percent, and the 15 largest for less than 50 percent, of national production.[19] Nor in general has production in more narrow geographic markets been highly concentrated; in the Permian Basin, for example, the five largest producers have accounted for somewhat less than 50 percent of production.[20] This degree of production concentration in the narrow market has been characterized as "lower than that in 75–85 percent of industries in manufactured products."[21] And, even if concentration were higher here than elsewhere, it has been shown that entry into the industry is so free that the largest producers would not be able systematically to charge higher than competitive prices.[22]

One rejoinder to this evidence of structural competitiveness is that ownership of *production* is not really relevant to the price of natural gas at the wellhead. Rather, the market relevant for field prices is that in the sale to pipelines of *rights* to take gas from *new reserves*. Petroleum companies sell gas under long term contracts which commit to pipelines 10 to 20 years worth of production from new reserves.[23] While such a contract typically contains a specified initial price, many used to have a "most favored nation" clause under which the actual price to be paid for the gas produced at any given time was pegged to the pipeline's then newest, most expensive contract.[24] Thus, once a production contract was signed, only the *level* of production was "locked in"; the *price* for gas produced under the contract would depend on the market for the sale and dedication of new reserves. Proponents of regulation have argued that ownership of uncommitted reserves was so concentrated that a few petroleum companies were able to raise the specified prices in new contracts by con-

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[18] Southern Louisiana Area Rate Cases, 428 F.2d 407, 416 n.10 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970).

[19] HAWKINS 248.

[20] Permian Basin Area Rate Proceeding, 34 F.P.C. 159, 182 n.17 (1956), *aff'd in part and rev'd in part sub nom.* Skelly Oil Co. v. FPC, 375 F.2d 6 (10th Cir. 1967), *aff'd in part and rev'd in part sub nom.* Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (approving FPC decision in its entirety).

[21] P. MACAVOY, THE CRISIS OF THE REGULATORY COMMISSIONS 156 (1970), quoting Champlin Oil & Refining Co., Docket No. G-9277, at 458 (FPC 1969) (testimony of Professor M.A. Adelman).

[22] *See* McKie, *Market Structure and Uncertainty in Oil and Gas Exploration*, 74 QUARTERLY J. OF ECON. 543 (1960).

[23] *See* HAWKINS 227; pp. 966–67 *infra*.

[24] *See* PRICE FORMATION 29–31.

trolling the supply of available natural gas reserves.[25] These higher prices were then passed through by triggering "favored nation" clauses in existing contracts, resulting in comparable prices for gas produced from previously dedicated reserves.

This argument, however, has little basis in fact. The available evidence [26] shows, for example, that the four largest production companies provided only 37–44 percent of new reserve sales in the West Texas-New Mexico producing area, 26–28 percent in the Texas Gulf region, and less than 32 percent in the Midcontinent region — all in the 1950–54 period just before the *Phillips* decision. These levels of concentration on the supply side of the market for new reserves were all less than half the concentration on the demand side, accounted for by the four largest pipeline buyers in each of these regions. Power to control new contract prices probably did not exist on either side of the market, but if the scales tipped at all, then surely the balance lay with the pipeline companies rather than with the producers.

Of course one can still argue that despite its apparently competitive structure, the producing segment of the industry has *behaved* noncompetitively. Certain proponents of producer regulation [27] have pointed to the rapid rise in the field price of natural gas between 1950 and 1958 [28] as evidence of such noncompetitive performance. But economic studies of the markets for new contracts suggest that anticompetitive producer behavior did not cause this price increase.[29] During the early 1950's the presence of only one pipeline in many gas fields effectively allowed the setting of monopoly buyers' (monopsony) prices for new gas contracts, thus often depressing the field price below the competitive level. During the next few years, several pipelines sought new reserves in old field regions where previously there had been such a single buyer. This new entry of buyers raised the field prices to a competitive level from the previously depressed monopsonistic level. In short, competition — not market power — accounted for much of the price spiral that has been claimed to show the need for regulation.

A further argument offered by those asserting the need to control the market power of gas producers was that producer

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[25] *Cf.* Champlin Oil & Refining Co., Docket No. G-9277, at 489 (FPC 1969) (testimony of Professor A.E. Kahn).

[26] *See* PRICE FORMATION 93–242.

[27] *See, e.g.*, Dirlam, *Natural Gas: Cost, Conservation, and Pricing*, 48 AMERICAN ECON. REV. 491 (No. 2, 1958); Douglas, *supra* note 16; Kahn, *Economic Issues in Regulating the Field Price of Natural Gas*, 50 AMERICAN ECON. REV. 506 (No. 2, 1960).

[28] HAWKINS 223 (prices at the wellhead increased 83% during this period).

[29] *See* PRICE FORMATION 243–73.

competition was ineffective in bringing about competitive prices because the producers' customers — the pipelines — did not have enough incentive to bargain for low prices.[30] Since pipeline final sales prices were (and are) regulated on the basis of costs plus a fixed profit on capital, it was argued that the pipelines failed to resist producer price increases and simply passed them on as "costs" to be paid by the consumer.

This argument is theoretically suspect, however, for strict regulatory supervision should make the pipelines worry about whether they will be able to pass along producer price increases, and weak regulatory supervision might allow them to keep any extra profits they earn through hard bargaining with producers — at least until "regulatory lag" catches up with them. In either case they should wish to keep producers' prices low. More important, given some limit on price increases set by some combination of consumer demand and regulatory awareness, pipelines should prefer to keep fuel costs (on which they earn no return) low in favor of enhancement of capital costs (on which they earn a return).[31] Furthermore, the evidence available suggests that pipelines in fact bargained for minimum prices. In the 1950's pipelines pushed field prices below competitive levels wherever possible. When low prices threatened to drive producers out of exploration and development, the pipelines themselves went into the exploration business rather than allowing producers to raise their prices. The transmission companies selectively produced higher-cost gas while paying monopsony prices for the low-cost gas from petroleum companies, thus keeping payment of excess returns to producers to the minimum.[32] In sum, empirical study provides little evidence to support the theory that unregulated field prices were noncompetitive.[33]

If the view that unregulated producer markets were in fact competitive is correct, then to regulate as if firms had market power would in principle only cause trouble. The FPC, with the monopoly rationale in mind, would reduce prices below the level

[30] *See, e.g.*, Douglas, *supra* note 16; Spritzer, *Changing Elements in the Natural Gas Picture: Implications for the Regulatory Scheme*, in REGULATION OF THE NATURAL GAS PRODUCING INDUSTRY 118 (K. Brown ed. 1972).

[31] On this point, most of the economic theories of the regulated firm agree. *See, e.g.*, Averch & Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AMERICAN ECON. REV. 1052 (No. 1, 1962). *See also* Baumol & Klevorick, *Input Choices and Rate-of-Return Regulation: An Overview of the Discussion*, 1 BELL J. OF ECON. MANAGEMENT SCI. 162 (1970).

[32] *See* PRICE FORMATION 93–145.

[33] Those favoring regulation have also pointed to producer profits as evidence of market power. To be sure, profits would appear to have been higher here than in some industries. Economic experts appearing for the distributing companies in the Permian Basin Area proceedings reported average returns on capital between 12

found in the unregulated market. But, since unregulated market prices were already the product of competition, any regulation would set prices below the competitive level. A lower than competitive price would stimulate demand, leading some buyers to use natural gas even though the economy could provide for their needs with other fuels at lower real costs. The lower price would also reduce the incentive of suppliers to provide new reserves and production, for the regulated price would not allow sufficient returns to producers at the margin. In short, the regulation-required price reduction would increase the quantity demanded and decrease the quantity supplied, thus causing a shortage.

B. Regulation to Reduce Rents and Windfalls

Under certain special circumstances one might want to regulate prices even in a competitive market. One would do so not to correct resource misallocations, but in order to redistribute income.[34] In principle, price in a competitive market will equal the cost of producing marginal output — the last units that can

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and 18% for oil and gas companies at a time when the average return in manufacturing was less than 8%. But such comparisons are not enough to suggest the presence of monopoly pricing, due to three special features of returns in the gas producing industry. First, without regulation, marginal producers must earn a return on their capital at least equal to what they could earn by investing elsewhere. But lower costs on more fortunate discoveries in a world of uncertainty might earn much more, and this "rent" earned by unusually efficient or fortunate producers would create an upward bias in industry average profit rates. Such "rent" is more likely to be prevalent in natural gas production than in most other industries because of the characteristics of discovery of an uncertain resource. *See* p. 950 *infra*. Second, the Permian Basin figures reflect profits only of firms still in business, not of those that have failed. The uncertainty in exploring and developing gas suggests that risks of failure have been unusually high. *See* HAWKINS 222 (showing high percentage of exploratory wells which have been dry). Thus, measuring industry returns on the basis of those that are able to remain in it results in an upward bias. Third, profit figures in the Permian Basin proceedings overstated the true return to capital because of the accounting procedures used. The rate of return estimates were calculated simply by dividing total profits that producers reported they had received by the total capital that they reported they had invested. However, this method does not account for the extensive time lag in the industry before an investment begins to earn a return. The accounting return on a dollar invested must be far lower in real terms here than elsewhere simply because payment begins 5 years, rather than 1 year, after the investment is made; the simple accounting profit rate must be adjusted to take the long lag between exploration and production into account. Producer witnesses in the Permian Basin case estimated that an "apparent yield" of 16 to 18% was due to the lag in production, equivalent to a "true yield" of about 10%. Thus, not much can be concluded about market power from the profit figures alone.

[34] Of course, regulation designed to allocate resources efficiently and regulation directed at income redistribution are not necessarily mutually exclusive policies. *See* p. 943 *supra*.

be sold. Some producers can sell at that market price intramarginal units that are far less costly to produce, perhaps because the producer has special skill, knowledge, or expertise, or controls a resource that cannot easily be duplicated. Such producers realize "rents" or excess returns, and the objective of regulation in such circumstances would be to transfer to consumers some of the income that low-cost producers would otherwise receive. It has been claimed that these rents are exceptionally high in the oil and gas industries, so that price control systems should be devised that would deprive producers of these excess returns and give them to consumers in the form of lower prices.[35]

Although no one has measured the amount of rent that gas producers would earn without regulation, there are reasons to believe that rents would be large compared to those earned in other industries. First, gas is a wasting resource, and its presence in the ground in commercial quantities is uncertain until exploration and development are complete. At that point, the value or price of gas is in theory set by the cost of marginal additional exploration and development (at least when demand for gas is increasing sharply, as it has been in the last two decades [36]). The difference between this cost of marginal additional exploration and development and the exploration and development costs of, let us say, the "lucky" producer who may have paid little for his land may constitute a considerable windfall. Of course, windfalls of this sort go in part to landowners who do not themselves produce gas but who have the ownership rights to the ultimate scarce resource (the location or site of the in-ground reserves). Strict control of producer prices, however, would prevent producers from paying these windfalls over to the landholders. Second, the cost of finding and developing gas reserves has increased considerably over the past two decades.[37] Thus, gas found and sold to pipelines 15 years ago in reserve commitments, but still not delivered, would have lower overall production costs than new reserves; such "old gas" may have even been found accidentally as part of the search for oil.[38] If production prices for this "old gas" were set at currently prevailing long term marginal exploration and development costs, its owners would receive appreciable windfalls or rents.

To eliminate these windfalls without interfering with the amount of gas produced, regulation would have to hold down

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[35] *See, e.g.*, Kahn, *supra* note 27.

[36] *See* Tables I and II, pp. 975, 978 *infra*. *See also* HAWKINS 220.

[37] Rising trends in costs of inputs and falling trends in productivity per unit of drilling are reported in NATIONAL PETROLEUM COUNCIL, U.S. ENERGY OUTLOOK ch. 6 (2d Interim Report 1971).

[38] *See* p. 944 *supra*.

the price charged to pipelines for intramarginal volumes of gas while allowing marginal units to be sold at a price equal to long term exploration and development costs. In effect, regulation would set different prices for different units of supply. Of course, such regulation would produce excess demand for the lower-priced intramarginal units received by the pipelines. To "clear" such excess demand by having the pipelines auction off these volumes would simply give windfall rents to the pipelines taking the highest bids. Rationing, on the other hand, might pass the windfall along to the retail distributor and presumably ultimately to the consumer.

This "tier" type of regulation is unusual, but not unheard of. Differential regulated prices are most commonly found in housing; rent control may hold down the price of existing housing while allowing the price of new housing units to rise so as not to discourage new building and to clear the market of demand for new rental units. But it is extraordinarily difficult to bring about the transfer of excess profits without affecting output. With regard to regulation of gas field prices, this requires extensive knowledge of the location and shape of the supply curve for both established production and new reserves. Moreover, if the reduced prices for intramarginal gas bring about the expected increase in the quantity demanded, then the excess demand has to be limited by recourse to such rationing devices as classifying users and designating one or more classes as "inferior" for purposes of allocating the lower-priced gas. To make such classification without reference to users' "willingness to pay," as measured by prices bid by users for the low-cost gas, is difficult, to say the least. In short, tier price regulation requires extraordinary sensitivity to changes in supply in order to react with necessary price changes, and, even in the best of conditions, it requires also a complicated rationing procedure.

Neither the Federal Power Commission nor the courts have clearly distinguished the two separate regulatory objectives of controlling market power and transferring rents to consumers, and often write as if they were trying to achieve both of them at once. Still, in view of the lack of empirical support for the "monopoly power" theory, we shall assume that regulating producers' market power is not a sensible regulatory goal. In fact, the Commission's writings in the past few years suggest that it has not pursued this goal with much fervor and indicate that the concern for income distribution predominates. For one thing, the Commission [39] and the courts [40] have expressed the belief or

[39] *See* Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86, 110–11 (1971).

[40] *See* Southern Louisiana Area Rate Cases v. FPC, 428 F.2d 407, 426 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970).

fear that efforts to limit price have reduced, rather than increased, the supply of new reserves and the actual level of gas production. Lowering prices from "monopoly" to "competitive" levels should have had just the opposite effect. The Commission's continued efforts to regulate, while holding this belief, suggest that it no longer sees itself as basically trying to control monopoly power. For another thing, the Commission has set two price levels in the area rate proceedings [41] — higher prices on "new" gas, and lower prices on "old" gas.[42] Its doing so, while at the same time expressing the hope that the new gas price would be high enough to cover the costs of producing new supplies,[43] indicates that limiting producer rents and windfalls is the more important concern underlying more recent regulation.[44] We shall assume that this is what the Commission has ultimately been trying to do.

II. Alternative Methods of Regulating Field Prices

After the Supreme Court's decision in *Phillips Petroleum Co. v. Wisconsin*,[45] the Federal Power Commission began to struggle with the problem of *how* to regulate.[46] The first approach was to treat producers as individual public utilities and to set limits on each producer's prices individually according to his "costs of service." After this approach proved unwieldy, the Commission set area-wide ceiling prices, allowing all individual producers within each gas production area to charge no more than the area ceiling.

A. Regulating Producers Individually

In attempting to regulate each gas producer, the Commission

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[41] *See* pp. 958–59 *infra*.

[42] This pattern appeared in the first complete area rate decision. Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1956), *aff'd in part and rev'd in part sub nom.* Skelly Oil Co. v. FPC, 375 F.2d 6 (10th Cir. 1967), *aff'd in part and rev'd in part sub. nom.* Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (approving FPC decision in its entirety).

[43] *See* 34 F.P.C. at 188.

[44] Additionally, economists favoring regulation upon whom the Commission has closely relied have often rested their case upon a belief that the supply of gas is inelastic — that price has little effect on outputs. *See, e.g.*, Kahn, *supra* note 27, at 508–09. If regulation-induced price changes would not affect output, then the only reason to set price ceilings would be to transfer rents.

[45] 347 U.S. 672 (1954).

[46] Soon after the *Phillips* decision, Congress passed a bill exempting field sales of natural gas from regulation. The bill was vetoed, however, by President Eisenhower, not because he favored regulation, but because he disapproved of certain producer lobbying tactics. *See* Kitch, *supra* note 5, at 256.

followed the same procedure it used to set prices for each gas pipeline. It sought the producer's "costs of service" and allowed prices sufficient for the company to recover these costs, but no more. This approach seemed to promise that no producing company would earn more than a reasonable return on its capital; producers with unusually low costs would not receive windfalls, but, instead, would have to charge their customers lower prices. This method of regulation also seemed to avoid the risk of a serious gas shortage. If costs increased producers could raise their prices, and, as long as there was demand for the higher-cost (and higher-priced) reserves, regulation would not inhibit production.

However, this summary description of individual producer regulation hides enormous problems. Although individual producer regulation allowed producers with different costs to sell at different prices, it provided no way to determine which gas users should get the more expensive gas and which the cheaper. And, even setting aside the difficulty of rationing the lower-priced gas, regulation of individual producers proved unwieldy because of the immense administrative burden it placed on the Commission. Most important, there were basic conceptual deficiencies in the regulatory method. Cost-of-service regulation was based on the assumption that it was possible to obtain detailed, accurate information about producer costs. It presumed that the cost of finding gas could be determined from accounting records, as can the costs of, say, gas pipelines, electricity generating companies, and telephone companies. Moreover, in searching for a proper rate of return on investment, the Commission assumed that gas producers' costs of capital could be rationally determined. But, as the Commission discovered, determining the costs of gas production and a proper rate of return to gas producers raises issues far less easy to resolve here — issues which require considerably more use of the regulator's subjective judgment — than in the case of traditional public utilities.

The difficulties the Commission experienced with individual producer regulation are typically attributed to management failure. The administrative burden placed on the Commission arose from the vast number of natural gas producers. In 1954 there were more than 4,500 producers,[47] and by 1962 they had submitted more than 2,900 applications for increased prices.[48] The individual price or "rate" case approach to regulation required finding which of the joint costs of oil and gas exploration and de-

[47] HAWKINS 37.
[48] *Id.*

velopment were attributable to gas alone, a judgment about the fairness of a particular rate of return on investment, and a determination of the proper amount of investment (or "rate base") for each of the 2,900 applications. To accomplish these tasks would have taken an interminable amount of time. The first producer rate case undertaken — the *Phillips* case itself — took 82 hearing days, with testimony filling 10,626 pages and a record including 235 exhibits.[49] Although later cases might have been handled more quickly, differences from case to case in both levels of costs and degrees of risk (and therefore in allowable rates of return) were such as to require some individual attention to each application. By 1960, the Commission had completed only 10 of these cases.[50] The backlog led the Landis Commission, appointed by President Kennedy to study the regulatory agencies, to conclude that "[t]he Federal Power Commission without question represents the outstanding example in the federal government of the breakdown of the administrative process." [51]

Management failure alone, however, does not account for the Commission's difficulties, for the problems of individual producer regulation went much deeper. Even if the Commission had had ten times the staff, it would have encountered severe conceptual difficulties in trying to separate the costs of oil and gas production and in setting a proper rate of return.

Finding the cost of natural gas posed several extraordinary difficulties which arose from the fact that gas is often produced in conjunction with petroleum liquids. Money spent by petroleum companies on *exploration* leads to the discovery of some gas wells, some oil wells that produce gas too, some pure oil wells, and many dry holes. Expenditures on *separate development* of gas fields often yield gas together with petroleum liquids, and expenditures on *gas refining* produce both "dry" gas and saleable liquid. Expenditures such as these, which yield two products but which are equally necessary to produce either one, complicate a regulatory process based on costs because there is no logical way to decide whether, or to what extent, a specific dollar outlay should be considered part of the "cost of gas production," or part of the "cost of liquid production."

This problem of joint cost allocation is distinctly a regulatory one. Without price controls and under competitive conditions, producers would recover marginal joint costs from the sale of

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[49] *Id.* at 26.

[50] *Id.* at 78.

[51] SUBCOMMITTEE ON ADMINISTRATIVE PRACTICE AND PROCEDURE OF THE SENATE COMM. ON THE JUDICIARY, 86TH CONG., 2D SESS., REPORT ON THE REGULATORY AGENCIES TO THE PRESIDENT-ELECT 54 (Comm. Print 1960) (Landis report).

gas and oil, with the relative amounts recouped from each varying from firm to firm.[52] If a regulatory agency controlled *both* oil and gas production, it might try to reproduce these competitive market results simply by requiring that the combined revenues from the sale of the two products be equal to their combined costs, including, of course, return to capital. Any combination of prices that would do no more than return total costs would meet this requirement.[53] The distinct regulatory problem in controlling field market prices for gas, however, was that liquid prices were not regulated by the FPC. Therefore, in order for the Commission to eliminate excess returns on gas production, it would have had either to find the "exact" costs of one of the joint products — something logically impossible to do — or to regulate indirectly the earnings on the unregulated sales of liquids — something it could not legally do.[54]

[52] Assume that to find and to produce a certain volume of gas and oil from a marginal well costs a certain producer $100,000. Assume further that of this cost, $70,000 is joint, $20,000 represents the ascertainable separate cost of extracting oil, and $10,000 the separate cost of extracting gas. The producer will develop this well and sell both gas and oil provided he can sell the oil for at least $20,000, the gas for at least $10,000, and the two together for at least $100,000. But he will not care whether the extra $70,000 comes entirely from gas sales, entirely from oil sales, or from some combination of the two. The source of the $70,000 will depend upon the relative strength of the demands of gas buyers and oil buyers for the producer's supplies — a factor which will depend upon supply and demand in each industry. *See, e.g.*, 1 A. KAHN, THE ECONOMICS OF REGULATION 79-83 (1970).

[53] Thus, the agency regulating the producer described in note 52, *supra*, would permit the well owner to recover $100,000, allowing him to set whatever combination of gas and oil prices would be necessary to obtain this revenue. Similarly, the regulator would allow the owner of an intramarginal well with, say, joint costs of $40,000, separate gas costs of $5,000, and separate oil costs of $10,000, to set whatever prices would obtain a total of $55,000. Since in the latter case total production could be sold for $100,000 in an unregulated market, the producer would lose $45,000 in rent, and gas and oil consumers *together* would pay $45,000 less than the free market price.

[54] The problem of trying to regulate one industry without regulating the other becomes clear if one considers the following procedure. Suppose the Commission were to require producers to submit prices that covered the costs of producing gas only, but which included (1) the ascertainable separate costs of gas extraction, plus (2) joint costs only insofar as they would not be covered by revenues received from the sale of petroleum. Thus, for example, a firm with joint costs of $70,000, separate oil costs of $20,000, and separate gas costs of $10,000, would be allowed to earn up to $80,000 from gas sales which would be calculated as the sum of $10,000 plus the difference between oil revenues (less $20,000 for covering *separate* oil costs) and $70,000. For every dollar less that it earned from oil sales, the company would be allowed to earn a dollar more from gas sales.

Considering the Commission's inability to regulate liquid sales, such a system for regulating gas production prices would have obvious drawbacks. First, it would require information on petroleum sales of the sort that is required of regulated sales. To ask the company to provide estimates of future oil prices would be to ask for exceptionally costly and uncertain information. Second, the Com-

The Commission's efforts to overcome .. joint cost problem in gas production in fact simply involved the application in various combinations of several traditional methods for allocating joint costs for accounting purposes.[55] But these methods only created the illusion that the joint costs of gas and oil production were separable and bore no particular relation to the problem of determining costs for rate setting. One method allocated joint costs according to the ratio of the separable cost of producing a barrel of oil to the separable cost of producing a thousand cubic feet (Mcf) of gas.[56] A second method allocated joint costs in proportion to the number of heating units (BTU's) contained respectively in the oil and gas produced.[57] A third method recognized that BTU's of oil and gas might not be of equal value in the marketplace, and therefore multiplied the BTU's by a factor representing relative value.[58]

None of the three procedures could yield either the long term costs of future gas production or the historical costs of past exploration and development. As methodology, they simply carried on a charade of implying separable costs when costs were joint and inseparable. In fact, if producers, in the absence of regulation, tended to recover most joint costs from oil revenues, and priced gas close to its ascertainable separate costs, the Commission's techniques, in allocating large shares of joint costs to gas, would force it to conclude that gas prices were too low. This fact may help to explain why the Commission held in the

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mission would have to regulate the price of oil eventually if it were to squeeze rents out of gas production. Under such a system, the producer would be indifferent as to whether he earned a dollar of rent from an oil or a gas sale. It is possible that he would try to cover as many of the well's costs as possible from gas sales, for if the Commission forced him to charge a lower gas price, he would not know whether he could cover a well's remaining joint costs from oil sales until the oil was sold, perhaps sometime in the future. He might therefore decide to maintain gas prices that included rents and reduce his oil prices, as a strategy to increase total sales or, perhaps, in order to allocate his low-priced oil arbitrarily on the basis of personal favors or otherwise.

[55] *See generally* HAWKINS 44–74.

[56] If, for example, it costs $1.50 to produce a barrel of oil and $0.15 to produce an Mcf of gas, joint costs would be allocated according to the ratio:

$$\frac{10 \times \text{the number of barrels of oil}}{\text{number of Mcf's of gas}}$$

[57] Under this method, if a barrel of oil yielded one million BTU's and an Mcf of gas yielded ½ million, then a company's joint costs would be allocated according to the ratio: $\frac{2 \times \text{number of barrels of oil}}{\text{number of Mcf's of gas}}$

[58] Thus, if an oil BTU was worth four times a gas BTU, the ratio for allocating joint costs would be: $\frac{4 \times \text{number of barrels of oil}}{\text{number of Mcf's of gas}}$

Note that this is a potentially circular method, since "costs" are partly tied to existing prices. *See* HAWKINS 46–47.

10 pre-1960 individual producer rate cases that it completed that producers' proposed prices would not generate enough revenue to cover costs.[59] In short, as Justice Jackson said in a slightly different context: [60]

> The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production . . . .[61]

A second theoretical problem which the Commision had to confront in attempting to regulate gas producers individually was that of determining a proper rate of return for each of them. While such determinations are usually difficult, here the difficulties were of more than usual magnitude. For one thing, there was no simple process for choosing industries with comparable risks. To be sure, producing gas is probably riskier than running a telephone company; but is it as risky as mining copper or making steel? Arguably, the cost of capital can be determined directly by watching share prices fluctuate on an exchange (or, possibly, comparable risk can be measured in this way [62]); but few producers sold shares on exchanges, and those that did were obviously the larger firms which produced both gas and oil. Nor was it possible to determine costs of capital by looking to producers' debt, because gas producers had issued insignificant amounts of debt securities.[63] Finally, because of different degrees of expertise and different quality of land options, risks varied tremendously among gas producers themselves. To determine the rate of return needed to cover producers' opportunity costs of capital would have therefore required many highly subjective judgmental decisions about thousands of different producers. These problems were compounded by the fact that capital costs accounted for a high portion of total production costs,[64] and thus posed a problem at least as serious as allocation of joint costs for individual producer regulation.

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[59] *See* HAWKINS 78.

[60] FPC v. Hope Natural Gas Co., 320 U.S. 591, 645 (1944).

[61] Since the number of joint wells has diminished to the point where gas output from them accounts for only about 25% of total gas production, *see* p. 944 *supra*, the problem of allocating joint costs became somewhat less important in the 1960's than it was in the 1950's. Nonetheless, joint expenditures were and are still sufficiently important to make a pricing system that allocates them via these accounting methods an exercise in the arbitrary.

[62] *See generally* W. SHARPE, PORTFOLIO THEORY AND CAPITAL MARKETS (1970).

[63] Because of special tax incentives, much new investment by gas production companies is financed out of internally generated funds. *See, e.g.*, INT. REV. CODE of 1954, §§ 611–13 (depletion allowance).

[64] *See* NATIONAL PETROLEUM COUNCIL, U.S. ENERGY OUTLOOK 115 (1972) (showing exploration, development, and overhead costs to be $6.4 billion of $8.9 billion total outlay).

The problems of determining the costs of production and the proper rate of return continued to plague the Commission as it turned to an administratively simpler regulatory method. And the Commission also continued to be plagued by the need to ration low-priced gas — as is any agency that tries to regulate competitive markets by setting different producer prices for sales of the same product at the same place and time.

B. Setting Area Rates

After regulation of individual producer prices proved unwieldy, the Commission embarked upon a policy of setting areawide ceiling prices, allowing all individual producers within a given gas production area to charge up to, but not above, the area ceiling. In 1960, the major gas producing regions were divided into five geographical areas,[65] and hearings were begun to determine the legally binding ceiling prices for each. Because of statutory limitations on Commission authority,[66] the area rate proceedings could set limits on prices only prospectively, *i.e.*, from the time an area rate proceeding was completed. Therefore, to control producer prices during the many years that the proceedings would be in progress, the Commission worked out a legally complex, though operationally simple, procedure which set "interim ceiling prices" at the 1959-60 levels for new contracts.[67] During the 1960's rate proceedings were completed only for the Permian Basin and Southern Louisiana areas.[68] In these and the remaining production areas, contracts for new reserves were written throughout much of the entire decade as if economic conditions had not changed since the late 1950's.

[65] The five areas were: (1) The Permian Basin (Texas and part of New Mexico); (2) Southern Louisiana (including the offshore area in the Gulf of Mexico); (3) Hugoton-Anadarko (part of Oklahoma and Kansas); (4) Texas Gulf Coast; and (5) Other Southwest (Mississippi, Arkansas, and parts of Alabama, Texas, and Oklahoma).

[66] 15 U.S.C. § 717d (1970).

[67] With regard to increases in existing contracts, proposed price increases would take effect subject to an obligation of the producer to refund any excess above the "reasonable rate" which the area rate proceeding was eventually to find. Thus, producers tended not to ask for increases above the interim ceiling rate. With regard to new supply contracts, the Commission used its licensing power over producer entry, 15 U.S.C. § 717 (1970), to withhold certificates allowing production to begin unless the producer agreed to sell the gas at the interim ceilings proposed by the Commission as (provisionally) reasonable. While the Commission did not rigidly adhere to these interim guidelines, its object was to hold new gas prices "in line" with those charged in the late 1950's and in 1960. *See generally* FPC, Statement of General Policy, No. 61-1, 24 F.P.C. 818 (1960).

[68] Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1965), *aff'd in part and rev'd in part sub nom.* Skelly Oil Co. v. FPC, 375 F.2d 6 (10th Cir. 1967), *aff'd*

In its area rate proceedings, the Commission sought to determine for each area two separate price ceilings: one for "new" gas from gas wells (new gas-well gas), and a second, lower ceiling that applied both to "old" gas from gas wells (old gas-well gas) and to all gas from oil wells. This two-tier area pricing system was designed to provide a fairly simple way to transfer rents from producers to consumers without seriously discouraging gas production and without imposing upon the Commission the administrative burdens of the multitier system of regulating producers individually. In embarking upon this new regulatory approach, the Commission assumed that gas found in conjunction with oil and old gas-well gas found several years before an area proceeding cost less to produce than new gas-well gas. It also assumed that the lower prices for old gas-well gas and gas found in conjunction with oil would not discourage their production, given that their supply was relatively fixed. Thus, lower prices for the old gas- and oil-well gas would deprive producers of rents from the sale of these supplies to the benefit of the consumer, while higher prices for new gas-well gas would, at the same time, encourage enough additional gas production to meet total consumer demands.

Despite its apparent logic and simplicity, however, the two-tier pricing system contained potentially serious flaws. First, given that excess demand would be generated for the cheaper "old" gas,[69] the FPC had to devise a way of rationing the available supply which would give it to those potential users who valued it most highly.[70] Home users, for example, value gas highly for cooking and heat, while industrial users may be nearly indifferent to the choice among gas, coal, and petroleum. An

in part and rev'd in part sub nom. Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (approving FPC decision in its entirety); Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530 (1968), *aff'd*, Southern Louisiana Area Rate Cases, 428 F.2d 407 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970). The latter case was reopened to raise the ceiling by 25%. Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86 (1971); *see* p. 964 *infra*.

[69] *See* p. 951 *supra*.

[70] The English have solved this problem by making the gas distributor a single nationalized company, with both monopoly and monopsony power. It can thus offer differential prices to producers based upon their production costs, including prices equal to marginal costs for producers at the margin. It can then ration the cheaper gas by selling to those consumers who bid the most. To be sure, the nationalized distribution company earns large rents, but these rents are simply transferred over to the treasury. *See generally* Dam, *The Pricing of North Sea Gas in Britain*, 13 J. LAW & ECON. 11 (1970). Of course, allowing private pipeline or distributing companies in the United States to ration the cheaper "old" gas on the basis of consumers' willingness to pay would be undesirable, since producer rents would then be transferred to these private companies, rather than to consumers.

auction system, by allocating the old gas on the basis of willingness to pay, would insure that it went to those who placed the highest value upon it. But an auction system would quickly drive the price of the "old" gas up to "new" gas price levels. In fact, the methods of rationing chosen by the Commission — allocating the cheaper gas on an historical basis (old customers before new ones) [71] or on the basis of an FPC determination that some *end* uses of gas were "inferior" to others [72] — do not seem to reflect an attempt to make careful distinctions among users according to their potential willingness to pay higher prices for the low-priced gas. These choices are important, since preferences made by the allocation system according to economically inefficient criteria are likely to spill over and affect other areas of economic activity; for example, insofar as historically-based differential prices at the wellhead are reflected in different pipeline resale prices, they may distort competition among industrial customers (*e.g.*, two chemical companies paying different prices for identical gas) or choices as to plant location.

Second, the competitive conditions of the unregulated gas production market suggest the strong possibility that, in a two-tier system where prices at both levels were set by regulatory action, the price of the higher tier would be set too low.[73] If so, then exploration and development of new gas would be discouraged, and there would be excess demand for the new gas as well as the old.[74] Here, again, if regulation-induced shortages occurred, additional economic inefficiencies would arise from any allocation system based other than on users' willingness to pay.

Third, this potential for economic harm from the two-tier system created by the inevitable excess demand for the lower-priced product and the probable regulation-induced shortage of the higher-priced product, was compounded by jurisdictional limitations on the FPC's power to regulate field market prices. Although the Commission could regulate producers' interstate sales, it could not regulate the prices at which they sold gas intrastate in the production region.[75] Intrastate sales were made pri-

[71] The FPC has generally chosen to increase the reserve backing of existing pipeline customers when given the choice of certifying new pipeline construction with only marginal backing.

[72] *See, e.g.*, FPC v. Transcontinental Gas Pipe Line Corp., 365 U.S. 1 (1961) (upholding FPC decision to deny delivery of gas to utility company for use under boilers in place of coal, partially on ground that this was an "inferior" use); p. 984 *infra*.

[73] *See* pp. 948–49 *supra*.

[74] A deficiency in the supply of the new gas might still occur even if the Commission regulated the old gas only, so long as producers suspected that there would be *future* designations as "old" of gas now "new." *See* pp. 984–85 *infra*.

[75] 15 U.S.C. § 717b (1970).

marily to industrial purchasers[76] who would seemingly be relatively indifferent as among various fuel sources available at equal prices. In times of shortage, the gas that these industries purchased would likely be diverted from retail distributors willing but unable under regulation to pay a higher price. Thus, both the certain scarce supply of old gas and the potential scarce supply of new gas likely would be disproportionately given over to certain industrial users by default, since other users who valued the gas more highly would not be allowed to bid up its price.

While the Commission may have intended the price of new gas to be set at market-clearing levels, the methods it used for setting new gas area prices made it highly likely that a significant gas shortage would arise by virtue of the new gas price — the "high" price — being set below the long term costs of natural gas production.[77] The basic method first used by the Commission to find a ceiling price for new gas-well gas was to determine by survey for given base years the recent cost of finding and producing new gas.[78] In both of the area rate cases completed in the 1960's, the final new gas price ceilings established on the basis of these estimates of recent costs turned out to be roughly equal to the interim prices set in the early 1960's.[79]

Given this recent cost survey method of setting the final ceiling prices, their similarity to the old interim prices is not at all surprising (even though one might have expected costs to rise during the 1960's), for the interim price ceilings themselves strongly biased the effort to determine the recent cost of new production. Producers unable to sell gas at more than the interim

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[76] *See* p. 977 & note 118 *infra*.

[77] Note that the discussion here is limited to the Commission's determination of prices for new *gas-well* gas, and that since no joint cost problem would be involved, it was unlikely the Commission would find the market price too low, as was the case in the former individual producer proceedings. *See* p. 957 *supra*.

[78] Thus in the Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1965), *aff'd in part and rev'd in part sub nom.* Skelly Oil Co. v. FPC, 375 F.2d 6 (10th Cir. 1967), *aff'd in part and rev'd in part sub nom.* Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (approving FPC decision in its entirety), the Commission staff surveyed both major and minor producers to discover their annual total costs for producing new gas for the base year of 1960. Experts employed by the producers, and some employed by retail distributors, made similar surveys. Together they produced a range of estimates of exploration and development costs for each of several different years. *See* HAWKINS 91–107. Similarly, in the Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530 (1968), *aff'd*, Southern Louisiana Area Rate Cases v. FPC, 428 F.2d 407 (5th Cir.), *cert denied*, 400 U.S. 950 (1970), such analyses were undertaken for the base year 1963.

[79] In Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1965), the Commission set a new gas ceiling price of approximately 16.5¢ per Mcf. In Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530 (1968), it set a new gas ceiling price of 20.0¢ per Mcf. The interim ceilings had been 16.0¢ and 21.0¢ respectively.

price levels most likely developed only those reserves having marginal costs lower than such prices. Companies with higher costs would not be producing, while those with cheap, lucky finds would still be in business. Thus it is not surprising that the recent costs of new reserves were slightly lower than the Commission's interim price ceilings. Taken together, the interim ceiling and later cost survey constituted simply two elements of a self-fulfilling prophecy; using recent costs to set future prices may, in reality, have been using interim prices to set permanent ones. In short, given the interim ceiling, a survey of the costs of producing new gas in the early 1960's could not tell the Commission with any assurance what price would be needed to elicit additional production for growing demand in the late 1960's and early 1970's.

Quite apart from the existence of interim ceilings, the probability that regulation would induce a natural gas shortage was increased by the specific calculation the Commission made to determine the recent costs of new gas production. If the Commission were not to discourage future production, it should have been certain that the ceiling prices it was setting were as high as prospective development and extraction costs. One indicator of such prospective outlays would be the cost curve derived from the historical marginal production costs in each drilling region of a production area during the test years. Even these historical marginal costs would of course understate future production outlays, because of increases in drilling and other expenses. But the Commission further compounded the possibility of understating prospective development and extraction outlays by *averaging* the marginal costs of recent production across all the drilling regions of a production area. Given a wasting resource from a fixed stock of uncertain size, it is highly probable that the costs of producing the very final units of recent output were greater than the average costs of finding and developing new reserves during the test years.[80] The higher-cost producers most likely included not only the unlucky or less skillful, but also those forced to search farther afield or deeper underground after having exhausted their more promising leaseholds. Averaging their costs in with the new gas production costs of the more fortunate or unusually skillful producers would understate the likely costs of future new gas production and would therefore increase the probability that exploration and development of marginal reserves would not take place.

The Commission tried to take these problems into account by

[80] *See generally* P. BRADLEY, THE COSTS OF PETROLEUM (1968).

adding an "allowance for growth" to the historical average costs of finding new gas. In the *Permian Basin* proceedings, for example, the Commision added 1.11 cents per Mcf to the ceiling price in recognition that producing enough new gas in the future to meet growing demands would probably require the exploitation of more expensive reserve sources.[81] But it did not determine the size of this premium by analyzing producers' probable marginal costs. Rather, an expert appearing for the gas distributing companies presented this figure as a judgmental observation, and experts for the gas producing companies in turn concluded judgmentally that the proper figure was 2.15 cents per Mcf.[82] The Commission simply chose between these two judgments, and, by acceptance of the distributors' estimate of the proper growth allowance, made it likely that the Commission's choice would be on the low side. To be sure, trying to determine the marginal costs of future gas production would have to involve *some* guesswork. But the need to guess inevitably introduces the risk of error — error difficult to correct once prices are set. The Commission's determination of the proper "allowance for growth" did not reflect any guidelines of its own concerning the impact of such factors as increases in drilling costs, decreases in the probability of finding gas, and changes in the rate of return needed to attract speculative capital into future gas production. Of course, as indicated earlier, these matters are highly speculative. It is therefore perhaps understandable that a Commission interested in regulating producers' prices would, when given only the alternative of accepting the producers' own figures, accept the growth figure offered by those interested in keeping producers' prices low.[83] But, nevertheless, the Commission's acceptance of the distributors' estimate of the premiums needed to encourage marginal production, along with its own calculation of the historical average costs of new production, created a considerable risk that the "new gas" price would be too low and would engender a gas shortage of some scope.

Faced with the extraordinary difficulty of determining the costs of "new gas" at levels of production that would clear the market and with a new-found shortage of gas production in the late 1960's, the Commission has more recently shown greater reliance on a process of direct negotiations to set area prices. In the original *Southern Louisiana* case, representatives of the producers, distributors, and other customers bargained out a "settlement" which was presented to the Commission for approval. The

[81] Permian Basin Area Rate Proceeding, 34 F.P.C. 159, 194 (1965).

[82] *See* HAWKINS 106–07.

[83] *Cf.* p. 948 *supra*.

Commission[84] and the appeals court[85] took the negotiation under advisement, however, along with a great deal of information on historical costs, and decided to set price ceilings slightly below the settlement figures. When the gas shortage in the late 1960's led the Commission to reopen the *Southern Louisiana* proceedings, once again the parties negotiated a settlement. This time the Commission adopted the settlement figures as its own, holding that they constituted reasonable ceiling prices.[86]

To be sure, one undeniable advantage of setting prices through such negotiation is administrative simplicity. The Commission need not spend as much time gathering evidence, the number of warring parties is reduced, and it is less likely that a disappointed party will convince a court to overturn a Commission decision. But to set ceiling prices in reliance upon industry settlements comes close to abandoning the Commission's espoused regulatory goals — whether they be to control market power or to eliminate windfall profits — and comes even closer to admitting an inability to achieve them. Negotiation among interested parties can hardly control monopoly power, for it bears little resemblance to the bargaining among buyers and sellers that takes place in a competitive market. Rather than competing individually for purchases or sales, the parties bargain in blocs — the buyers together in one bloc bargaining with producers in the other bloc. Whether the negotiated price ends up higher than, lower than, or equal to the competitive market price will vary depending on the skill of particular bargainers and the bargaining atmosphere surrounding the negotiation. The parties are likely to be constrained in the bargaining by their knowledge that the Commission and the courts must approve the result and may produce little more than what they perceive their regulators as wanting.[87] For these same reasons, negotiation is unlikely to pro-

[84] Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530, 543 (1968).

[85] Southern Louisiana Area Rate Cases v. FPC, 428 F.2d 407, 419 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970).

[86] Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86, 110 (1971); *see* Hugoton-Anadarko Area Rate Proceeding, 44 F.P.C. 761, 769–72 (1970) (ceiling price based on settlement). *But see* Texas Gulf Coast Area Rate Proceedings, 45 F.P.C. 674 (1971) (ceiling price based on independent FPC determination).

[87] Thus, for example, in the first *Southern Louisiana* case, the industry probably surmised that the Commission was unlikely to approve any price out of line with past prices or that departed too radically from average historical new gas production costs. It is therefore not surprising that the settlement offered in that case came very close to the "interim" ceiling price. *See* Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530, 630 (1968). Once the Commission reopened the proceeding, however, and thereby indicated its willingness to raise the ceiling price to alleviate the gas shortage, the settlement offer produced a price 20–25% higher than the price previously allowed. Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86, 110 (1971).

vide "accurate" two-tier prices in an effort to drive out producer rents.

In sum, the difficulty of designing a two-tier system for regulating field prices for natural gas made it unlikely from the outset that the Commission would set the "high" price for new gas at a market-clearing level if that was what it intended to do. However, it is also possible that the Commission in fact *wanted* to set the "high," new gas price below competitive rates. Much new gas-well gas production as well as old gas- and oil-well gas production probably returns rents to its producers.[88] If the Commission wanted to return these rents to users, while setting a *single* area price for all new gas-well gas, it *had* to set the price below the marginal cost of new production in that area. The Commission may have felt that any necessarily resulting shortage would not be serious and would be worth the benefits of lower prices to consumers who could obtain the gas that would be made available. If this was the Commission's reasoning, though, it did not expressly state it. Moreover, even if Commission policy could be attributed to such a purpose, the wisdom of that policy would still depend upon the precise extent and impact of the gas shortage created by it. It is to that question that we now turn.

III. The Extent and Impact of the Natural Gas Shortage

The expectation that FPC regulation of gas production was likely to produce a substantial gas shortage has been proven accurate by subsequent events. Thus, pipeline buyers have reported to the Commission instances during the summer and winter of 1971–72 in which their contracts obliged them to deliver gas but they lacked the necessary supply.[89] The FPC staff has shown deliveries falling short of gas demanded by 3.6 percent in 1971 and by 5.1 percent in 1972, and has predicted that production will fall short of demand by 12.1 percent in 1975.[90] Moreover, those feeling the pinch have tended to blame FPC regulation for the shortage.[91] And the FPC has not only acknowledged the existence of a substantial shortage,[92] but has also suggested

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[88] *See* p. 950 *supra*.

[89] *See Proceedings on Curtailment of Gas Deliveries of Interstate Pipelines Before the Federal Power Commission* (1972).

[90] FEDERAL POWER COMMISSION, BUREAU OF NATURAL GAS, NATIONAL GAS SUPPLY AND DEMAND 1971–1990, at 123 (1972).

[91] *See* MacAvoy, *The Regulation-Induced Shortage of Natural Gas*, 14 J. LAW & ECON. 167, 169–70 (1971) [hereinafter cited as *Regulation-Induced Shortage*].

[92] *See* NATURAL GAS SUPPLY AND DEMAND, *supra* note 90, at xi; FEDERAL POWER COMMISSION, BUREAU OF NATURAL GAS, THE GAS SUPPLIES OF INTERSTATE NATURAL G. S PIPELINE COMPANIES 1968, at 34–39 (1970).

that regulated prices are a cause.[93]

Production "shortfalls" alone, however, do not accurately describe the extent of the gas shortage, because gas is purchased by and sold to pipeline companies before the time of its actual production. Gas delivered during any given year is "backed up" by considerable volumes of reserves which are originally committed in long term contracts to pipeline companies demanding a guarantee as to future supplies. Obviously, pipelines will demand more than a few years of reserve backup, for only with a fairly long term supply guarantee is establishing a pipeline worthwhile. More importantly, retail distributors and industrial consumers normally demand that pipelines themselves guarantee a specific rate of delivery over time and therefore demand substantial reserve backing as security against default by the pipelines on their promised deliveries.[94] Thus, an inability of transmission companies to acquire sufficient supplies to meet contract delivery requirements in any given year should signal the earlier existence of a deficiency in the volume of backup reserves committed at the time the original production contracts were undertaken. If this view is correct, a shortage in production levels in the 1970's would have been prefaced by a deficiency of reserve commitments made to back up new production undertaken in the early and mid-1960's. The extent of this predicted reserve shortage in the 1960's should be measurable as the difference between an "optimal" level of reserves which would have been demanded by pipeline companies to back up new production undertaken in that period and the level of reserves actually supplied by regulated producers and acquired by the pipelines.

Rough calculations previously made by one of these authors in fact show the shortage of reserve inventory of natural gas during the 1960's to have been substantial.[95] This conclusion was reached by first determining an approximate "optimal" volume of gas reserves, in terms of years of backup supply, which would be dedicated to secure new production commitments undertaken in any single year. The FPC has considered the proper amount of reserves to be 20 times initial production, so that regulated pipeline demands for new reserves have been based on "the assumption that each new market commitment is backed by a

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[93] *See* Southern Louisiana Area Rate Proceeding, 46 F.P.C. 86, 110–11 (1971).

[94] In theory at least, this demand for reserves should be reflected in higher contract prices to the pipelines, because a longer waiting period for production imposes higher costs on the supplier. This cost increase was not reflected in significantly higher prices on longer term contracts, however, during the period just before area rate regulation. *See* PRICE FORMATION 162–65.

[95] *Regulation-Induced Shortage* 171–75.

20 year gas supply."[96] Similarly, pipelines' actual demands for reserves from 1947 to 1954 — before the Commission had much influence on the field markets — were on average equivalent to a 20-year backup of production, with the lowest backing in any single year equal to 14.5 times new production.[97] It was therefore concluded that, on the most conservative of assumptions, a simple, rough estimate of demands for reserve inventory under ceiling prices could be obtained by multiplying total new production — including all new contracts plus any renewals of expiring contracts — by 14.5 to obtain the "lowest" demands for reserve backing in the unregulated market. Alternatively, on more liberal assumptions, total new production could be multiplied by the FPC's suggested reserve ratio. These calculations were done for the years 1964 through 1968 to determine the volume of natural gas which would have been demanded by pipelines as reserves to back up new production under "optimal" conditions for that period. These high and low "optimal" volumes were then compared to the actual new-reserve-to-new-production ratio for the same years. Taking the 5-year period as a whole, it was found that the total demand for reserves was 1.5 to 2.2 times higher than the actual reserves acquired under FPC price ceilings; therefore, *excess* demand for reserves was 50 percent to 120 percent of realized levels of commitments.

In an attempt to determine whether this reserve shortage was the result of field price regulation, we shall construct a model of supply and demand for new reserves, based upon market clearing conditions in the 1950's. These conditions will then be extrapolated into the 1960's in order to predict what supply and demand behavior would have been like during that decade under competitive conditions and whether FPC ceiling prices were too low to clear the market.[98] Then we shall proceed to determine who received gas and who suffered the shortage. It will be shown that, in fact, as suggested earlier the home consumer suffered the brunt of an FPC-created reserve shortage, while the unregulated industrial consumer received a disproportionate share of the gas that was available.[99]

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[96] FEDERAL POWER COMMISSION, A STAFF REPORT ON NATIONAL GAS SUPPLY AND DEMAND 18 (1969). Note that 20 years of reserve backing will support only 12 years of delivery at the full initial production rate, because the rate of delivery out of a reserve must fall as gas pressure falls. *See* HAWKINS 42.

[97] *Regulation-Induced Shortage* 172.

[98] Obviously, the proposed model is fallible due to the many problems involved in acquiring data — problems that the Commission itself faced in trying to set prices. Yet we believe that such models should be used by policymakers as evidence that is probative, though not conclusive, of which policies ought to be followed.

[99] ED. — Professor MacAvoy has previously published a supply and demand

A. A Supply and Demand Analysis of the Insufficiency of FPC Ceiling Prices

The proposed model of supply and demand in the field markets for natural gas in the 1960's tries to assess more accurately the extent to which field price regulation caused the gas shortage. The model tests the fairly plausible view that, without regulation, field prices for natural gas would have increased substantially, producing correlative increases in the supply of and decreases in the demand for natural gas reserves. These higher prices would have called forth enough new supply to fill at least part of what has been shown to be the excess demand for reserve inventories. And, by more carefully rationing the available supply, the higher prices would have eliminated whatever additional excess demand would have still remained.

The proposed model applies to gas which is supplied by pipeline to the East Coast and Midwest.[100] To test the model's accuracy, we first construct supply and demand schedules to characterize unregulated market behavior in the latter half of the 1950's and use these schedules to predict market-clearing prices in that period. This is done by fitting 1950's data to the proposed supply and demand relations to predict the amount of reserves added in year "t" in producing district "j" (ΔR_{tj}) and the average new contract price at the same time and place (P_{tj}). The values of ΔR_{tj} and P_{tj} that "clear" this supply-demand system for the 1950's describe with considerable accuracy both the actual prices at which natural gas was sold and the actual amount of new reserves added in the test areas during that period. The

model intended to measure the extent to which field price regulation has caused the natural gas shortage. MacAvoy, *The Regulation-Induced Shortage of Natural Gas*, 14 J. LAW & ECON. 167 (1971). Since that time, his thoughts on the subject have somewhat modified, and the model presented herein is a considerably revised and updated version of that previously published and yields different results.

For those familiar with Professor MacAvoy's earlier model, the revised version presented here specifically differs in the following respects. First, the long term pattern of reserve discoveries and wells sunk in a drilling region is taken to be a better indicator of the geological conditions of that region than is the pattern of discoveries and drilling the year before the test year. Second, the level of the crude oil price index replaces that of the all fuels price retail price index as a condition of drilling activity. Third, the capital stock of gas burning furnaces is taken to be a closer measurement of the size of the final market for natural gas than changes in per capita income and population.

In addition, the data used to examine the relative effects of the gas shortage on industrial and residential users has been developed more fully and separates intrastate from interstate production insofar as it is possible to do so.

[100] The test field market is delimited by the pipelines taking gas for resale along the East Coast and in the Middle Atlantic states. The area roughly comprises Texas Railroad Commission Districts 1-7 and 10, Louisiana, Kansas, and Oklahoma.

model is then applied to the 1960's by inserting 1961–68 data into the supply and demand equations and then solving the system for market-clearing values ΔR^*_{tj} and P^*_{tj}. The model's values for the 1960's are then compared to the actual reserves added and prices existing during that period. The comparison shows regulated prices to be less than P^*_{tj} and actual reserves supplied to be less than one-third of ΔR^*_{tj}. Most of the difference can be attributed to the FPC's regulatory efforts.

1. The Supply Equations. — As previously indicated, the supply of natural gas is measured both by the volume of new reserves *and* by the level of production added from new contracts each year.[101] Looking first at the supply functions for new gas reserves, the volume of new reserves discovered and developed in any given year depends on geological and technical factors, as well as economic ones. Thus, the supply equations of the proposed model relate observable data to the supply of new reserves on the following assumptions.

First, the volume of gas added to known reserves in a district depends quite plainly on the extent of hydrocarbon deposits in that district; gas discovery, in other words, cannot occur where the deposits are not present. Because of the relative permanence of geological characteristics, the most concrete determinant of general hydrocarbon availability in a district is the long term pattern of reserve discoveries there. Thus, it may be said that the supply of new reserves in year "t" in district "j" (ΔR_{tj}) is a function (f) of the geological characteristics of district "j" itself. This relationship can be expressed by the equation $\Delta R_{tj} = f(j)$.[102]

The second condition of new reserve supply is that inputs are required — principally drilling inputs — to bring unknown hydrocarbons to the point of being producible reserves. The only available data on such inputs are the number of gas development wells sunk in the 1950's and 1960's, by drilling district. To be sure, such data are not indicative of all necessary inputs, but the wells do reflect the amount of capital invested in a hydrocarbon field and do provide producers with additional knowledge of surrounding geological conditions. Thus, the supply of new reserves in year "t" in district "j" (ΔR_{tj}) is also a function of the number of development wells sunk in the same time and place (W_{tj}). In sum, the equation $\Delta R_{tj} = f(j, W_{tj})$ can be taken to indicate, even if somewhat imperfectly, a number of important "engineering" factors in the supply of new reserves.

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[101] *See* p. 966 *supra*.

[102] The actual values of "j" are determined for purposes of the supply and demand equations by treating it as a "dummy" variable. *See* note 109 *infra*.

Third, the supply of newly discovered reserves also depends upon economic factors. This relationship can be most immediately seen as a condition of the number of development wells sunk in a drilling district. Thus, as prices for new gas reserves increase, it can be expected that more gas drilling will occur, and this additional drilling of regions likely to contain gas will increase the amount of new gas reserves dscovered. If average new reserve contract prices in year "t" in district "j" (P_{tj}) are good surrogates for the prices forecast by the drilling companies before development begins, then the amount of actual drilling (W_{tj}) will be a function of these prices. In addition, as noted previously, gas reserves may be discovered incidentally in the search for oil.[103] Oil price increases are likely to produce more drilling in areas likely to contain hydrocarbon deposits, and such drilling may produce gas, as well as oil, finds. Therefore, the number of development wells sunk (W_{tj}) may be said to be also a function of the level of the crude oil price throughout the Southwest (op_t). Thus, the response of drilling activity, and indirectly of new reserve supply,[104] to economic factors can be expressed by the equation $W_{tj} = f(P_{tj}, op_t)$.

Finally, the analysis of drilling, as well as that of reserves, should recognize that geological factors, as represented by the long term pattern of drilling in a region, are important. Thus, the drilling equation we have developed thus far, $W_{tj} = f(P_{tj}, op_t)$, should include the geological characteristic j as well.

In sum, the supply functions for new gas reserves in each drilling region "j" supplying the East Coast and Midwest markets in year "t" within the late 1950's can be taken to be:

$$\Delta R_{tj} = f(j, W_{tj}), \text{ where}$$
$$W_{tj} = f(P_{tj}, op_t, j).$$

Turning to the supply of new production, as opposed to new reserves, the proposed model is based on the assumption that the quantity of additional production from new contracts signed in year "t" for gas in district "j" (ΔQ_{tj}) depends upon three factors. First, the quantity of additional production obviously is a function of the volume of newly discovered reserves at the same time and place (ΔR_{tj}). Second, production depends upon the costs of production itself. These costs may be roughly represented by the current rate of interest (i_t), since the interest rate

[103] *See* p. 944 *supra*.

[104] The effect of these economic factors on new reserve supply arises, of course, because ΔR_{tj} is partly a function of W_{tj}.

may be assumed to be a measure of capital costs for drilling. As these costs increase, the production rate out of new reserves should decrease. Third, the quantity of additional production from new contracts signed each year is a function of short term consumer demand for immediate gas delivery. One of the factors influencing short term consumer demand can be represented by the all fuels retail price index (fp_t). This index will indicate not only whether the price of substitute fuels is rising, thereby making gas more desirable, but perhaps also whether personal consumption of fuel generally is on the rise, increasing the demand for gas as one among a number of alternative fuel sources. In short, additional gas production from new purchase contracts signed each year ($\triangle Q_{tj}$) is taken roughly to be a function of the availability of new reserves ($\triangle R_{tj}$), production costs (i_t), and consumer demand (fp_t), and can be represented by the equation $\triangle Q_{tj} = f(\triangle R_{tj}, i_t, fp_t)$.

2. *The Demand Equation.* — Demand or "willingness to pay" is represented by the prices bid by pipelines to purchase new gas reserves. These bids are determined primarily by pipeline costs and the pipelines' opportunities for resale. Thus, the proposed model is based on the assumption that average new contract prices for gas reserves of district "j" in year "t" (P_{tj}) depend upon pipeline costs and the demand for gas in final consumer markets.

The price a pipeline is willing to offer for newly discovered gas is in part a function of the pipeline's transport costs. These costs depend both upon the volume of new reserves discovered in a district and the distance between the field and the point of resale to retail distributors. As the volume of new reserve discoveries in a district ($\triangle R_{tj}$) increases, companies will be able to install larger scale gathering lines, thereby reducing unit transport costs. On the other hand, costs will rise as the number of miles between the field and the point of resale to retail distributors (M_j) increases.[105] Thus, the relation between field prices in district "j" in year "t" (P_{tj}) and pipeline transport costs can be expressed by the equation $P_{tj} = f(\triangle R_{tj}, M_j)$.

A more important determinant of the prices pipelines will bid, however, is final consumer demand. As pointed out earlier,[106] the index of all fuel retail prices (fp_t) provides a rough measure of such user demand for gas; the prices which pipelines are willing to pay for producer gas are likely to increase directly with increases in this index. On the other hand, user demand will be limited by the total size of the final user market, and measure-

[105] A diagrammatic exposition of this argument is presented in PRICE FORMATION 37-41.

[106] P. 971 *supra*.

ment of demand can be made more accurate by considering the extent of this market. The size of the market can be initially estimated by the capital stock of all gas-burning furnaces in the country (K_t). Moreover, since there are limits to the level of resales by pipeline companies, the prices which these companies are willing to pay in any year will depend on the sum total of *all* new reserves that year ($\Sigma\Delta R_{tj}$). Thus, as the capital stock of gas burning furnaces (K_t) increases, so will the likely price bid by the pipelines; but as total new reserves offered in any year ($\Sigma\Delta R_{tj}$) increases, the likely price bid will decrease. Therefore, the relation between average new contract prices (P_{tj}) and the demand and size of final markets can be expressed by the equation $P_{tj} = f(fp_t, \Sigma\Delta R_{tj}, K_t)$.

In sum, putting together both the cost and user demand determinants of the prices pipelines are willing to pay, the proposed demand relation (for the same regions and time periods as for the supply functions) is: $P_{tj} = f(\Delta R_{tj}, M_j, fp_t, \Sigma\Delta R_{tj}, K_t)$.

3. Application of the Model to the Field Market for Gas. — The four equations of the proposed model together make up ar equilibrium system that describes well the actual prices and supplies of new reserves in the late 1950's. Data from the period 1955–60 were used to fit "least squares" equations[107] to the structural relations explained above for new reserves (ΔR_{tj}), wells sunk (W_{tj}), new production (ΔQ_{tj}), and average contract price (P_{tj}).[108] The closeness with which the fitted equations describe reality is indicated by the accuracy with which equilibrium

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[107] A "least squares" equation is a common statistical method which minimizes the sum of the squared differences between the actual observations and the estimates provided by the fitted equation.

[108] The market-clearing solutions for the endogenous variables ΔR_{tj}, ΔQ_{tj}, W_{tj}, and P_{tj} depend on the outside or "exogenous" variables j, op_t, $\Sigma\Delta R_{tj}$, K_t, fp_t, M_j, and i_t. Data series for each of these variables were constructed for the preregulatory period in the eleven drilling regions that provided gas on contracts to pipelines serving the East Coast and Midwest. The data used in the calculations were all obtained from publicly available sources. For the variables ΔR_{tj}, ΔQ_{tj}, W_{tj}, P_{tj}, fp_t, M_j, and i_t, the sources used are summarized in *Regulation Induced Shortage* 197–99. Data for the variables K_t and op_t were obtained from U.S. DEP'T OF COMMERCE, CURRENT BUSINESS STATISTICS, as accumulated over the period 1954–68. For the method of estimating the value of the "dummy" variable j, see note 109 *infra*.

These data were used to fit the supply and demand relations by first stage least squares equations for each of the endogenous variables separately, given the exogenous variables, and then the fitted values $\Delta\hat{R}_{tj}$, $\Delta\hat{Q}_{tj}$, $\hat{W}_{tj}$, and $\hat{P}_{tj}$ from the first stage were used to find the second stage least squares supply and demand equations. The fitted supply and demand equations were therefore four least squares regressions, one for the supply of new reserves, the second for the supply of wells, the third for new production, and the last for the demand for new reserves.

in the four-equation system reproduced the actual volumes of new reserves supplied and prices paid during the period.[109] The difference between the "simulated" (four-equation equilibrium) price and the actual annual average price in any given year was at most 1.6 cents per Mcf and the average difference over the

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[109] The equations for the number of wells sunk and for the supply of new reserves for the 1955–60 period were as follows:

$$W_{ij} = -648.60 + \underset{(1.73)}{11.46}\ \hat{P}_{ij} + \underset{(1.75)}{175.52}\ op_i + \sum_{1}^{10} a_i J_i\ ; \qquad R^2 = 0.734$$

$$\Delta R_{ij} = -5.41 + \underset{(0.98)}{2.45}\ \hat{W}_{ij} + \sum_{1}^{10} b_i J_i\ ; \qquad R^2 = 0.831$$

The sets of variables $\Sigma a_i j_i$ and $\Sigma b_i j_i$ are district dummy variables taking the value "one" for observations from district j and "zero" otherwise. This method of treatment of the geological differences between districts follows from F. FISHER, SUPPLY COSTS IN THE U.S. PETROLEUM INDUSTRY (1964).

As these equations show, there were positive cumulative effects from well drilling, new gas contract prices, and the crude oil retail price index. The elasticity of reserve supply with respect to new contract gas prices was estimated to be equal to 0.51 at the average 1956 price and level of new reserves, so that a 10% price increase would lead to a general 5.1% increase in discovery of new reserves.

The equation for additional production was as follows:

$$\Delta Q_{ij} = -34.33 + \underset{(2.89)}{0.015}\ \Delta\hat{R}_{ij} - \underset{(-2.27)}{27.49}\ i_i + \underset{(2.75)}{11.37}\ fp_i\ ; \qquad R^2 = 0.693$$

This shows a positive production-reserve relation, a negative production-interest relation, and a positive production-fuel price relation. The elasticity of production with respect to reserves was approximately 0.40, and was quasi-statistically significant. The elasticity with respect to interest rates was negative, and with respect to the fuel price index was positive. Both coefficients were quasi-significant and had the expected effect on production: the higher the capital cost (i_i), the lower the production rate; and the higher the price of alternative fuels (fp_i), the higher the gas production rate.

The demand equation was also estimated in the second stage of two stage least squares as follows:

$$P_{ij} = \underset{(8.43)}{12.22} + \underset{(-1.12)}{0.0012}\ \Delta\hat{R}_{ij} - \underset{(-1.95)}{0.00094}\ \Sigma\Delta R_{ij} - 0.0013\ M_j$$
$$+ \underset{(0.99)}{0.088}\ fp_i + \underset{(5.02)}{0.00083}\ K_i\ ; \qquad R^2 = 0.616$$

As the equation shows, there were positive coefficients for three variables and negative coefficients for two variables. The elasticity of gas prices with respect to the fuels price index was +0.02, and with respect to the "size" of the resale market (K_i) was +0.05. These values are low, indicating small responsiveness of bid prices to change in the values of these variables. However, the elasticity of demand was substantial; a small change in prices P_{ij} brought forth large changes in total new reserves demanded ($\Sigma\Delta R_{ij}$) so that this elasticity equalled at least −1.6. The other elasticities — for variables ΔR_{ij} and M_j differentiating the drilling regions — were as expected from the economics of pipeline costs and demand.

entire 6-year period was only 0.7 cents per Mcf.[110] Similarly, while the volumes of actual new reserves exceeded simulated new reserves by approximately 3 trillion cubic feet in both 1955 and 1957, the average difference over the 6-year period was less than ½ trillion cubic feet (or less than 0.7 percent of total new additions to actual reserves).[111] The model thus suggests that markets "cleared" — or operated at equilibrium — in the 1950's before producer price regulation.[112]

In order to test whether the gas shortage in the following decade developed from price controls, the model was then applied to the 1960's. The four equations were used, along with 1961–68 figures for the "outside" or exogenous variables,[113] to find the values for ΔR^*_{tj}, ΔQ^*_{tj}, W^*_{tj}, and P^*_{tj} which "solve" the equations — *i.e.*, the values which "clear" the gas market as if there were no price ceilings. These "unregulated" values are compared with the actual values in Table I.

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[110] The results for each of the test years in the late 1950's are as follows

	Actual Average Price (¢ Mcf)	Simulated Average Price (¢ Mcf)
1955	15.5	16.6
1956	17.0	17.9
1957	18.1	18.4
1958	19.3	18.8
1959	19.1	19.7
1960	18.4	20.0
6-year	17.9	18.6

[111] The actual additions to reserves, and the simulated "unregulated" additions in the 1955–60 period, are as follows.

	Actual Reserves (billions cu. ft.)	Simulated Reserves (billions cu. ft.)
1955	7,354	10,678
1956	14,439	10,935
1957	15,236	12,361
1958	13,604	12,578
1959	11,239	12,381
1960	10,036	12,481
6-year	71,908	71,414

The tendency seems to have been for more new reserves to have actually been provided in the earlier years than simulated by the model. This tendency was reversed in the later years. Anticipation of the approaching price controls — with consequent reductions in supply — could have had much to do with this trend

[112] Three other equation sets were fitted to the data as well. One set used the pattern of reserve discoveries and drilling the year before the test year as an indicator of geological conditions; thus, lagged values of the dependent variables, *i.e.*, $R_{t-1,j}$ and $W_{t-1,j}$, were used in place of the district "dummy" variable "j." *See* note 109 *supra*. A second set was fitted in the logarithms of all variables, and the third was fitted in the logarithms of the demand variables only. Of the four systems, the one reported in the text and the previous footnotes simulates best the 1955–60 experience in reserves, production, and prices.

[113] *See* note 108 *supra*.

TABLE I

PRICES AND PRODUCTION OF GAS FOR THE EAST COAST AND THE MIDWEST, 1961–1968

Year	Average Price (¢/Mcf)		New Production (billions cu. ft.)		New Reserves (billions cu. ft.)	
	Actual	Simulated	Actual	Simulated	Actual	Simulated
1961	17.7	20.0	292	817	5,567	12,480
1962	19.0	21.1	230	755	5,805	12,858
1963	16.5	22.4	447	688	4,884	13,077
1964	16.7	22.9	200	814	5,512	13,221
1965	17.4	24.1	348	750	6,015	13,621
1966	17.2	25.5	347	627	4,204	14,147
1967	17.4	26.7	575	520	3,693	15,026
1968	18.0	27.8	434	548	951	15,572
8 years	17.5	23.8	2,873	5,519	36,631	110,002

The simulated or "unregulated" prices that would have cleared the reserve market were on the average 6 cents per Mcf higher than ceiling prices for the entire period, and more than 7 cents higher for the period following 1962, when the full effect of price ceilings seems to have taken hold in the test region. On the supply side, the higher prices — if they had been allowed — would have provided considerable incentive to add to the volume of new reserves. The level of simulated new reserves is more than three times the level of actual new reserves over both periods. Another indication of the impact of clearing prices on supply appears in the difference between actual and simulated new production. Actual new production is approximately one-half of simulated new production over the 8-year period. Given that higher unregulated prices would have brought forth a much higher level of new reserves, this higher level of simulated new production is not surprising. On the demand side, the higher simulated (market-clearing) price would have significantly reduced the amount of reserves sought. To be sure, the amounts which would actually have been demanded at various prices are not known, since only the new reserves both demanded *and* supplied are shown by the annual simulations. But that excess reserve demand would have been reduced is indicated by the fact that the total demand for new reserves proved to be elastic with respect to price.[114] Total new reserve demand was reduced by approximately 10 trillion cubic feet for each cent of price increase.[115]

[114] *See* note 109 *supra*.

[115] It is interesting to use the data in Table I to try to compare roughly the

As it was, a serious reserve shortage developed in the 1960's, which at that time revealed itself in the pipelines' reduction of their new-reserve-to-new-production ratio. This reduction in the security of service, shared by all those connected to interstate pipelines, was translated in the early 1970's into a more tangible actual production shortage; pipelines had to curtail deliveries in 1971 and 1972 because they could not take gas from their reserves fast enough to meet their contract commitments. This production shortage has been plainly visible. It followed directly from the earlier reserve shortage which in turn was a creature of FPC regulatory policy.

B. The Impact of the Shortage

At the same time that field price regulation has meant lower gas prices, it has also brought about a reserve — and now a production — shortage. Determining who has been helped and who

extent of reserve backing for actual and simulated new production in the test region. Taking the 8-year period as a whole, simulated additional production is 5% of simulated new reserves, and during the period 1963–68, it is 5.2% of new reserves. This would seem to indicate approximately between 19 and 20 years reserve backing for new production under "unregulated" conditions. *See* pp. 966–67 *supra*.

However, this calculation really overstates the extent of reserve backing supplied to guarantee new production, because the production figures provided by the model are for *additional* production only — *i.e.*, the quantity of production in excess of production the previous year. The figures do not include the extent of new production in the test years which would have been supplied under "unregulated" conditions to *replace* production contracts expiring in those years. It has been previously estimated that such replacement demand equals 1/14 of *total* production in any one year, based upon the depletion rate of new reserves in 1947. *See Regulation-Induced Shortage* 173–74 & n. 15. Figures for total production in the test region under "unregulated" conditions are not provided by the model, and therefore replacement production cannot be calculated from the data in Table I. To be sure, inclusion of replacement production would reduce the reserve-to-production ratio below the level of 20 years reserve backing for new production. But, since the model predicts conditions which would "clear" the "unregulated" market, the higher simulated prices would have reduced demand for new reserve backing down to the level of that supplied. And, given higher prices, replacement production is unlikely to be so high as to take reserve backing under "unregulated" conditions outside the range of 14.5 to 20 years considered "optimal" to guarantee future service. *See* pp. 966–67 *supra*.

The *actual* reserve backup provided for new production in the test years was far lower. For the 8-year period as a whole, actual *additional* production was backed up by 12.8 years of reserves, and during the period 1963–68, reserve backup was only 10.7 years. Because of the necessity eventually to reduce the rate of production out of a reserve as a result of falling pressures, *see* note 96 *supra*, this means that reserves supplied during the latter period would support only about 6.4 years of production at the initial rate. And, of course, if the new-reserve-to-new-production ratio were decreased to reflect new *replacement* production, this figure would be even lower.

has been hurt by this FPC regulatory policy is necessary in order to assess whether the lower prices were "worth" the shortage. Information is not yet available to allow a definitive finding on this issue. Nevertheless, there is enough evidence inferentially to support the view that the result of FPC policy in the 1960's was to deplete the gas reserves of interstate home consumers in favor of the demands of intrastate industrial customers to whom sales were unregulated.

First, the regulated pipelines — those selling interstate for resale to distributors for most home customers — did not obtain their proportionate share of new gas reserves in the late 1960's. In 1965 these lines possessed more than 70 percent of the nation's reserves. But between 1965 and 1971, the interstate pipelines obtained less than half the volume of the new reserves developed, and the overall percentage of reserves possessed by them fell to 67 percent.[116]

Second, as Table II shows, what variation there was in the division of total annual gas production between residential and industrial users indicates that over the course of the 1960's proportionately more went to industrial users. The percentage of gas sold by pipelines and distributors to residential users declined 1.6 percentage points between 1962 and 1968.[117] This decline was caused in large measure by a substantial increase in industrial sales by unregulated intrastate pipelines and by producers themselves. Between 1962 and 1968, total industrial consumption of natural gas increased 43.5 percent, while intrastate pipelines and distributors increased their industrial sales by almost 62 percent.[118] Moreover, of the increase in industrial consumption, more than half can be attributed to sales by intrastate pipelines and distributors, while less than 13 percent is accounted for by direct industrial sales of the interstate pipelines. The remaining 37 percent of the increase was the result of direct sales by the producers.

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[116] *Hearings on Natural Gas Policy Issues Before the Senate Comm. on Interior & Insular Affairs*, 92d Cong., 2d Sess., pt. 1, at 192, 268, 270 (1972) (Statement of FPC Chairman Nassikas).

[117] *See* P. Balestra, The Demand for Natural Gas in the United States: A Dynamic Approach for the Presidential and Commercial Market (1967). Balestra describes the period referred to in text as that in which gas sales were "reallocated" between classes of customers. He describes 1950–57 as an "innovating" period in which pipelines were built and service begun and 1957–62 as a "maturing" period in which more gas was sold to the same customers.

[118] The substantial increase in the category "Distributors and Intrastate Pipelines" came primarily from sales by unregulated transmission companies. This is demonstrated by data gathered by the authors which show that sales by regulated pipelines to distributors for resale to industry increased at a rate only slightly greater than the rate of increase for "Total U.S. Industrial Consumption." By

TABLE II

NATURAL GAS SALES TO ULTIMATE USERS [a]

Class of Service or Seller	1962 Quantity (mil. Mcf) [b]	1962 Percent of Total	1968 Quantity (mil. Mcf) [b]	1968 Percent of Total	Percent Increase
SALES BY ALL PIPELINES AND DISTRIBUTORS					
Residential and Commercial	4,320	44.5	5,966	42.9	+38.2
Industrial and Other	5,396	55.5	7,925	57.1	+46.9
Total	9,716	100.0	13,891	100.0	+43.0
SALES TO INDUSTRIAL AND OTHER NONRESIDENTIAL CONSUMERS					
Direct Sales by Interstate Pipelines [c]	2,129	23.2	2,641	20.0	+24.0
Intrastate Pipelines and Distributors (est.) [d]	3,267	35.5	5,284	40.0	+61.7
Producers [e]	3,809	41.3	5,284	40.0	+38.7
Total U.S. Industrial Consumption	9,205	100.0	13,209	100.0	+43.5

[a] Much of the data in the table is derived from AMERICAN GAS ASSOCIATION, GAS FACTS 1971, at 82, 119 (1972).

[b] This figure was converted from million therms to million Mcf based on 1,031 BTU's per cubic foot of natural gas.

[c] *See* FEDERAL POWER COMMISSION, STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES 1962, at XXII (1963); FEDERAL POWER COMMISSION, STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES, 1968, at XV (1969).

[d] These figures are derived by subtracting "Direct Sales by Interstate Pipelines" from the figures for "Industrial and Other" sales by all pipelines and distributors.

[e] These figures are derived by subtracting "Direct Sales by Industrial and Other" sales by all pipelines and distributors from the figures for "Total U.S. Industrial Consumption."

Third, that the reserve shortage hit most seriously the residential buyer supplied by a regulated pipeline becomes still more evident when certain particular gas regions are examined. The Permian Basin in West Texas, for example, accounted for about 2.5 percent of total U.S. gas reserves in the early 1960's. In the late 1960's, additional discoveries raised this figure to about 10.5 percent.[119] Six large interstate pipelines, two intrastate pipelines, and many direct industrial buyers bid for the new reserves.[120] From 1966 onwards, the intrastate lines and the direct industrial buyers obtained almost all of the uncommitted volumes available. In fact, interstate pipelines, which accounted for 80 percent of production from the new reserves in this area in 1966, accounted for only 9 percent in the first half of 1970.[121] The reason for the interstate pipelines' decline in reserve holdings is not difficult to find. Prices offered by intrastate buyers for the new gas in this area rose from 17 cents per Mcf in 1966 to 20.3 cents per Mcf in 1970, and toward the end of 1970, the intrastate pipelines bought more than 200 billion cubic feet of reserves at initial delivery prices of 26.5 cents per Mcf.[122] At the same time, prices paid by interstate pipelines could not exceed the regulatory ceiling and therefore remained between 16 and 17 cents per Mcf. The inescapable conclusion is that the interstate pipelines were simply outbid.

In sum, as a result of regulation in the 1960's buyers for interstate consumption obtained fewer reserves than they wished. For the most part, those buyers were pipelines ultimately serving primarily residential consumers. The short reserve supplies were bid away from these buyers by intrastate gas users. This was a predictable result of FPC two-tier regulation of field gas markets in light of the Commission's jurisdictional limitations.

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compiling the interstate pipelines' Form 2 Reports to the FPC, state totals for all pipeline sales were obtained. The percentage of sales to industry in each state was obtained from BUREAU OF MINES, ANNUAL REPORTS ON GAS CONSUMPTION and applied to those state totals to produce the figures, by state, for pipeline sales to distributors for industry. These sales increased by 50% from 1962 to 1968, significantly below the 62% increase registered for total industrial sales by "Intrastate Pipelines and Distributors" given in Table II.

[119] *See* AMERICAN PETROLEUM INSTITUTE, AMERICAN GAS ASSOCIATION, PROVED RESERVES OF OIL AND NATURAL GAS IN THE U.S. (Annual Volumes 1965–70).

[120] PRICE FORMATION ch. 5.

[121] *Hearings, supra* note 116, at 295, 298 (testimony of J. C. Swidler, Chairman, N.Y. Public Service Commission).

[122] Reply Submittal of the Office of Economics, Federal Power Commission, Initial Rates for Future Sales of Natural Gas for All Areas, Docket No. R-389A, at 12, 19 (Oct., 1970).

IV. The Costs of Regulation

Showing that ceiling prices created a substantial gas shortage and that this shortage was disproportionately borne by residential gas consumers is not enough by itself to condemn FPC regulatory policy. At the same time that FPC regulation of field markets created a shortage, it also reduced prices 6 cents per Mcf below what we have simulated market-clearing prices to be during the 1960's. To calculate the gains to consumers who actually received gas as a result of this regulatory policy, one might simply multiply average annual production of regulated gas from, say, 1962–68 (about 11 trillion cubic feet),[123] by 6 cents per Mcf and claim that regulation saved those consumers who received gas about $660 million annually. Of course, such a calculation contains heroic assumptions and oversimplifications. For one thing, it assumes that every cent of price reduction at the wellhead was passed through to ultimate consumers; in light of the fact that sales by retail distributors are intrastate and therefore subject only to state regulation, the assumption may not be valid.[124] For another thing, had producers received a higher price, at least some of their additional revenues would have been taxed away and, therefore, indirectly returned to consumers anyway. Nonetheless, even assuming that the entire 6 cents per Mcf was returned to consumers who actually received gas, we still doubt that this benefit outweighed the losses arising from regulation, even from the point of view of the consumer class itself.

In order to calculate the costs of wellhead price regulation to gas users, it must first be established that the behavior of pipelines in the field market is representative of consumers' interests. Table I [125] showed that the additional 6 cents per Mcf which pipelines would have paid for gas produced under unregulated conditions would have purchased a joint product: *both* additional production *and* additional reserves. These hypothesized purchases of additional supply by pipeline companies likely represent what the pipelines conceived to be final consumer demands for additional current deliveries and for additional insurance of future deliveries. Obviously, pipelines would not overstate demands for current production, since they clearly have no interest in purchasing gas which they cannot resell. Similarly, it is difficult to see why pipelines would deliberately overstate demand for reserves, given that the costs of dedicated

[123] *Hearings*, *supra* note 116, at 163, 192, 270 (Statement of FPC Chairman Nassikas).

[124] *Cf.* Hawkins 212.

[125] *See* p. 975 *supra*.

reserves are not included in their rate base and demanding excessive reserves would increase contract prices and therefore ultimately reduce sales to consumers.[126]

If this assumption of the representative quality of the pipelines' field market demands is correct, then the cash returned to gas users by virtue of FPC regulation was probably less than the cash consumers were willing to give up for additional deliveries and reserve backing. First, the gains to those paying lower prices for gas they actually received must be offset by the losses to others who had to do without gas and find other sources of energy. Residential and commercial users unable to receive gas because distributors lacked supply — usually those consumers in new or growing population centers — were forced to use less desirable, or more expensive, fuels such as oil or electricity. The cost, in real terms, to these consumers of using such alternative energy sources can be roughly measured by the amount which they were willing to pay for additional gas. Therefore, the loss they suffered from regulation is the difference between what they *were willing to pay* for gas rather than go without it and *what they would have actually paid* under equilibrium conditions for the market-clearing level of gas deliveries. If this difference or "premium" which consumers suffering the shortage were willing to pay was on *average* 6 cents per Mcf, then the losses of those doing without gas were as great as the gains of others receiving gas at 6 cents per Mcf below market-clearing prices; this is so because the hypothesized *shortage* of new production (the difference between simulated and actual production out of new reserves in Table I) was approximately as large as *actual* new production.[127] In fact, it appears from the supply and demand model

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[126] *See* p. 948 *supra*.

[127] The discussion in text describes in layman's terms what the economist calls "consumers' surplus." Consumers' surplus is defined as the excess over the price paid which consumers are willing to pay for a given amount of a product rather than do without it. *See, e.g.*, G. STIGLER, THE THEORY OF PRICE 78 (3d ed. 1966). When a market is at equilibrium, the market-clearing price equals what consumers are willing to pay for the last or marginal unit of output. Since consumers would normally be willing to pay more for intramarginal units of output, the equilibrium price affords them a savings or "surplus" on these intramarginal units. This savings which gas consumers suffering the shortage would have had under unregulated conditions is a measure of the cost to them of the FPC policy. It can be represented diagrammatically as follows on p. 982, note 127 *infra*.

At the level of production supplied under price ceilings (Q_{fpc}), consumers, as represented by the pipelines, were willing to pay a price for gas not only above the FPC ceiling (P_{fpc}), but considerably above the market-clearing price (P_{market}) as well. Moreover, for each unit of additional production up to market-clearing levels (Q_{market}), consumers were willing to pay more than the market-clearing price. Thus, the area of the triangle ABF is equal to the difference between what that consumers suffering that shortage would by 1967 or 1968 have been willing to pay an average premium of 6 cents per Mcf rather than do without gas entirely.[128] Therefore, the losses from the shortage (equal to what consumers in the aggregate were willing to pay to recover lost gas production) simply made too many consumers worse off to allow the conclusion to be drawn that reduction in prices was worth the shortage it created.[129]

Second, the argument that consumers who actually received

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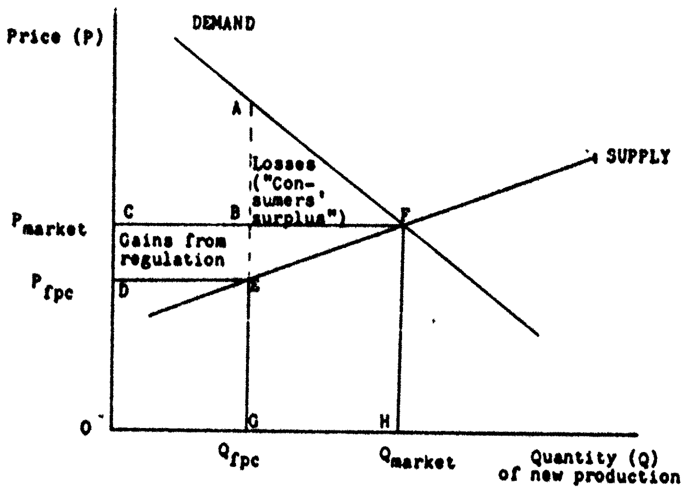
consumers doing without gas were willing to pay for additional production ($Q_{market} - Q_{fpc}$) and what they would have actually had to pay for it under market-clearing conditions (equivalent to the rectangle BFHG). This surplus which consumers who actually did without gas would have obtained under hypothesized market-clearing conditions represents the losses to them from FPC price ceilings.

These losses to consumers doing without gas can be compared to the gains by consumers who obtained new gas production. These gains are represented by the area of the rectangle CBED. This area is the difference between the market-clearing and FPC price ($P_{market} - P_{fpc}$) multiplied by the quantity of new gas production they received (Q_{fpc}). Thus, if the area of triangle ABF is at least equal to the area of rectangle CBED, then the gains to those who received gas were offset by the losses by those who had to do without.



[128] In other words, in the diagram given in the previous footnote, the length of line AB was, in fact, at least twice the length of line BE by the last years of the test period. Since the shortage of new production by 1967–68 exceeded the actual supply of new production, line BF was greater than line CB.. Thus, the area of the triangle ABF was at least equal to the area of the rectangle CBED.

[129] Of course, this is somewhat of an overstatement, since the model shows consumer losses being at least equal to consumer gains only with regard to *additional* production during the test years. In reality, the 6 cents per Mcf reduction in price brought about by FPC ceilings was a gain realized by consumers on other gas as well — *i.e.*, the amount produced under old contracts which would have sold for higher prices when "favored nation" clauses were triggered. *See* p. 946 *supra*. This amount is unknown.

gas obtained a 6 cents per Mcf saving as a result of FPC regulation is itself fallacious, because these consumers were, in fact, purchasing *less* — an inferior product — than they would have under unregulated conditions. As we have shown, the price which consumers pay for deliveries, when translated into the price pipelines pay for production at the wellhead, purchases not only current production, but also a reserve backing which provides a certain level of insurance of future deliveries. Since FPC price ceilings brought forth only a third of the new reserves which would have been developed under market-clearing conditions, those consumers who received gas at lower prices *gave up* a substantial amount of their guarantee of future service. To be sure, this loss was not observable by these consumers, since it took the form only of reduced backing for production which they were currently receiving. Nevertheless, it is likely that these reserves were worth a considerable amount to them. The man who makes a large investment in gas appliances, for example, obviously wants an assurance that he will not have to switch to oil or electricity for many years, if at all. Reserves promise him this and also provide him with security from possible temporary interruptions of service. On conservative assumptions, these buyers, as represented by the pipelines, wanted at least 14.5 years of reserve backup to provide them with a sufficient production guarantee.[130] Under unregulated conditions, this insurance would have been obtained by them; under FPC price ceilings, it was not.[131] The 6 additional cents per Mcf which consumers receiving gas would have had to pay in an unregulated market was, from the perspective of their interests, at least in part a premium for insurance which FPC price ceilings did not provide. For every 6 cents in cash which FPC regulation saved these consumers on actual deliveries, it took away reserves which they might well have desired at least as much as the money. In short, the extent to which FPC regulation actually helped even those receiving gas at lower prices is problematical; it simply gave them a short term windfall at the cost of long term insecurity.

These losses to both those who did not obtain gas and those who did, moreover, are not all the costs of the FPC's regulatory policy. For example, further costs probably resulted from the displacement of industry. Some industrial firms for whom energy costs were a large part of total costs moved to the producing states solely to obtain natural gas not available on the interstate market due to FPC price ceilings. Moreover, further distortion arose from competitors' paying different prices for their fuel sources, either because one had an intrastate gas supplier, or because of FPC

[130] *See* p. 967 *supra*.

[131] *See* note 115 *supra*.

policies for rationing the cheaper "old" gas. And the economic and administrative costs of litigation and delay from the price proceedings themselves have been substantial as well.[132]

Despite these strong indications of the failure of FPC regulation of field gas prices, some consumers' groups have argued that the Commission should deal with the problems that have arisen from its present regulatory efforts by introducing still more regulation. The Commission might, for example, seek to expand its jurisdiction over intrastate sales to end the "leakage of supply" to intrastate industrial users and then establish "end use" controls, specifically allocating gas to particular individuals or classes of customers.[133] Such an approach, however, would not solve the problems raised here. Not only would it fail to reduce the aggregate shortage of gas, but it would require the Commission to determine on a larger scale than it now does which end uses of gas are "superior" and which "inferior." Such a task is difficult, to say the least, and there is little reason to believe that a Commission that was unable to set area prices in the field without creating massive shortages would find a "proper" solution to the still more complex problem of rationing on a grand scale. Once prices were abandoned as a measure of value, the number of claimants for special preferences, citing a variety of economic and social imperatives, would become large indeed. In all probability, the Commission would have to continue its past practices and simply arrange for a series of compromises among these various claimants. Such compromises would inevitably lead to continued excess demand for gas and to shortages in which, if the future resembles the past, those intended to benefit from gas regulation would still be injured.

Neither would it be completely satisfactory for the Commission to follow a partial policy of income redistribution by trying to squeeze rents only from old gas- and oil-well gas production while leaving new gas-well gas production unregulated.[134] To be sure, there would be little danger of shortage if the Commission set ceiling prices only on the production of gas *now* classified as "old," since there is *ex hypothesi* a fixed supply of these hydrocarbons. But such regulation would accomplish merely a temporary, minimal transfer of rents, because the supply of this "old" gas will run out in the next few years. In order to accomplish this temporary income transfer, the Commission would

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[132] *See, e.g.*, Gerwig, *Natural Gas Production: A Study of Costs of Regulation*, 5 J. LAW & ECON. 69 (1962).

[133] *See Hearings, supra* note 116, at 302 (testimony of J. C. Swidler).

[134] President Nixon's recent proposal, *see* p. 942 *supra*, seems to contemplate adoption of this alternative.

still have to solve the problems of determining the costs of producing old gas and of rationing the cheaper supplies. The administrative burden of solving these problems might not be worth the income redistribution which such a policy would bring about. On the other hand, if the Commission embarked upon a *permanent* policy of regulating "old" gas prices by continuously reclassifying further supplies as "old," it would not only have to develop a dynamic standard to separate "old" from "new" gas, but it would also be confronted with all the problems of the present regulatory system. Producers seeing that the prices of their new supplies would *eventually* be subject to ceilings would be likely to take these future price regulations into account. Therefore, while the prices of new reserves would not be directly regulated, further exploration and development would still be discouraged, and thus a shortage would still arise.

The alternative that we favor is eliminating field price regulation designed to transfer producer rents. If income is to be redistributed, rents can be transferred from producers to consumers without regulation. For example, tax policy can be used to accomplish the same objectives. Indeed, much of the alleged justification for the depletion allowance [135] in this area — the need to encourage exploration and development — would seemingly vanish if producer prices were set competitively. In contrast to the tax system, area price ceilings cannot help but be an indiscriminate method of income redistribution. While it takes *some* income from those producers realizing excess profits, its impact falls most heavily on those producers without excess profits — those right at the margin, perhaps forcing them out of the market entirely. In contrast, redistribution through taxation aims more directly at those producers with excessive incomes. While we are aware that redistribution through tax policy has many problems of its own, we doubt that they could be as serious as those that have accompanied the effort to control field prices. In short, it is difficult to see the virtue of a price control system, particularly when, as was proven during the 1960's, it is likely that those consumers the system is designed to benefit will not be benefited at all. With the example of producer price regulation in mind, one might well question the advisability of using microeconomic methods — such as regulation of the firm — solely to accomplish macroeconomic objectives — such as income redistribution.

To be sure, elimination of regulation intended to redistribute income would effectively mean deregulation of much of the field market for natural gas, since the market structure of most, if not all, producing regions is decentralized and competitive. De-

[135] INT. REV. CODE of 1954, §§ 611–14.

regulation of this sort, however, would not deprive the Commission of all power over producer rates in those regions where producers do possess monopoly power. At the same time that the Commission would allow prices in competitive regions to approach market-clearing levels, it could selectively regulate prices in those few producer regions where market power turns out to be present by using the prices in the competitive areas as benchmarks.

Of course, one potential obstacle to this proposed regulatory policy is that a court might hold that for the Commission to allow market forces to determine producer prices would be inconsistent with the mandate of the Natural Gas Act to regulate "sale[s] in interstate commerce of natural gas . . . ." [136] To be sure, in the *CATCO* case,[137] the Court held that the Commission could not license a producer to sell gas without conditioning the license on the producer's promise to charge a reasonable price. But the Court's decision in that case was predicated on the inadequacy of the Commission's findings respecting the need to issue an unconditional license, and on the harms to consumers which would attend the inordinate delay before the Commission on its own could determine a just and reasonable rate. Certainly, the case cannot be taken as precedent for disturbing Commission judgment that market forces can ordinarily be relied upon to set just and reasonable rates and that any attempt to interfere with market forces to transfer rents would do the consumer more harm than good. A decision to "deregulate" producer prices as proposed would be a determination that selective rather than pervasive interference with field market transactions was the most appropriate way to regulate this portion of the natural gas industry. Such a determination would seemingly comply with the fundamental purposes of the Natural Gas Act, and, being based upon 15 years of experience with different methods of regulation, it would almost certainly be supported by substantial evidence.[138] Nothing in the *Phillips Petroleum* decision [139] *requires* the FPC to set prices; the decision simply gives the Commission jurisdiction to do so. As the U.S. Court of Appeals for the Fifth Circuit has recently stated: [140]

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[136] 15 U.S.C. § 717(b) (1970); *see* note 5 *supra*.

[137] Atlantic Refining Co. v. Public Service Comm'n of New York, 360 U.S. 378 (1954).

[138] Courts will normally review administrative decisions to see if they are in compliance with law and are supported by substantial evidence on the whole record. *See* Universal Camera Corp. v. NLRB, 340 U.S. 474 (1951).

[139] *See* p. 941 and note 5 *supra*.

[140] Southern Louisiana Area Rate Cases, 428 F.2d 407, 416 n.9 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970). *See also* Permian Basin Area Rate Cases, 390 U.S.

> [T]he decisions of the Supreme Court definitely indicate the Commission has a responsibility to take the steps necessary to assure that wellhead prices are in the public interest. The Commission does not have to employ the area rate method or for that matter regulate prices directly at all, but it has chosen to fulfill its duty in that manner here.

In sum, the arguments against the present system of gas field market regulation are compelling. Price control is not needed to check monopoly power, and efforts to control rents require impossible calculations of producer costs and lead to arbitrary allocation of cheap gas supplies. In practice, regulation has led to a virtually inevitable gas shortage. It has brought about a variety of economically wasteful results, and it has ended up by hurting those whom it was designed to benefit. Thus, less, not more, regulation is required.

747, 766–67 (1968) (one who would overturn FPC finding of fact bears heavy burden of proof); Wisconsin v. FPC, 373 U.S. 294, 309 (1963) ("[i]t has repeatedly been stated that no single method need be followed by the Commission in considering the justness and reasonableness of rates"); FPC v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944) ("Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling.")

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Appendix E

Federal Energy Research and Development Funding

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Executive Office of the President, Office of Science and Technology

FEDERAL ENERGY R&D FUNDING*

The Federal Government each year spends significant sums on research and development aimed at improving the methods for locating, producing, converting and transporting both the primary energy sources—petroleum, gas, coal, uranium and water power—and the secondary energy source—electricity. Research is also underway to develop new advanced sources such as oil shale, fusion energy geothermal steam, and solar energy. The government also supports research on energy in high demand fields such as transportation, housing, etc.

During the past several years, there has been major new emphasis and significant funding increases in energy R&D. A major source of this emphasis has been concern over how the nation is to meet its growing demands for energy without degrading the environment.

Five-Year Survey of Federal Energy R&D

Federal energy R&D funding for the past five years has been assessed by staff members of the Office of Science and Technology, and their results are presented by major categories in Tables I and II. In summary, however, energy R&D funding increased over 72%, or $261 million, from FY 1969 to FY 1973. This represents a compounded growth rate of more than 11%. The increase is due in part to expansion of several key efforts including the fast breeder nuclear reactor, coal gasification, sulfur oxide removal from fossil fuel stack gases and controlled thermonuclear fusion.

Although the funding increase is probably the survey's most striking feature, another is an obvious trend toward a Federal R&D program which balances the energy resources of the nation and the engineering R&D required to utilize those resources most effectively. For example, coal resource R&D funding has been growing at a much faster rate than nuclear power funding, 305% compared to 29% over the five-year period. Significant increases in funding for stack gas cleanup

*This memorandum does not reflect increased Federal energy research and development funding announced by President Nixon in November, 1973. See Table 7, page 27.

technology and coal gasification are aimed at making the nations abundant coal resources available for both electric generation and industry. Where nuclear fission accounted for 77% of the FY 1969 energy R&D budget, it now accounts for only 58%. In the meantime, funding for the liquid metal fast breeder reactor has grown by 97% thus reflecting its changing status as a national priority program. Controlled thermonuclear fusion, geothermal steam, and solar energy have also received considerably more attention as funding patterns evolved.

The FY 1973 Federal Energy R&D Budget

In his Energy Message to Congress on June 4, 1971, the President announced a broad range of actions including a forward-looking agenda for research to ensure adequate future supplies of clean energy. To meet the challenge spelled out in the Energy Message, Federal agencies have vigorously expanded their efforts in critical areas and the overall energy R&D budget for fiscal 1973 was increased by $96.9 million or about 18.4%.

The major increases were aimed primarily at developing adequate supplies of clean electrical energy while simultaneously enhancing the quality of national life through long and short term R&D. Coal gasification and liquefaction, magnetohydrodynamics, the liquid metal fast breeder, controlled thermonuclear fusion, cryogenic generation and transmission, geothermal steam and solar energy account for 74%, or $72.0 million, of the increase.

R&D programs are underway to provide new technological options for resolving conflicts between energy needs and environmental protection. For instance, to help meet stricter air and water quality standards related to energy use, FY 1973 funding will be expanded $21.5 million or 22.5%.

The FY 1973 funding pattern clearly reflects the objective of achieving a more strategic approach to our national R&D investment. A stronger R&D partnership between government and industry is a crucial component of this approach. The Atomic Energy Commission and the electric utilities are building a demonstration fast breeder reactor and the Department of Interior and the American Gas Association are working on coal gasification, both efforts excellent examples of such partnerships.

The utilization of the outstanding capabilities of the high technology agencies to deal with domestic problems such as energy needs is another key component. Examples include the Atomic Energy Commission's work on high energy density storage batteries, dry cooling towers, and underground transmission lines and the National Bureau of Standard's research on cryogenic generation.

Industrial Energy R&D

In addition to the electric utility industry's major cooperative commitments to the demonstration breeder reactor, it is also planning a vast exapnsion of the Electric Research Council's voluntary, private sector R&D activities as described in a recent report entitled "Electric Utilities Industry R&D Goals Through the Year 2000." Private research and development efforts in the petroleum industry are less well documented due to the tradition of properietary research and development. Historically, however, the petrolum industry has spent considerably more on research and development than the other sectors of the energy industry combined.

Highlights of Major Energy R&D for FY 1973—Nuclear Fission R&D

The largest single high priority item in the energy R&D budget is for the development of the liquid metal fast breeder reactor (LMFBR) by the Atomic Energy Commission and industry. The anticipated Federal funding for FY 1973 is approximately $260 million. The LMFBR will expand, by a factor of 30 to 40, the energy obtainable from natural uranium thus assuring abundant supply of low-cost electrical energy for centuries. A demonstration of LMFBR plant by 1980 is a mid-term goal. The long-term objective is to develop a broad technological and engineering base with extensive utility and industrial involvement. This will lead to an economic breeder design and the establishment of a strong commercial breeder industry in the mid-1980's.

The first demonstration plant, a joint Government/industry undertaking, is expected to be built by the TVA and Commonwealth Edison of Chicago using funds from all segments of the electric utility industry and the Government. The Fast Flux Test Facility in Hanford, Washington, and other engineering test and development facilities are included in the AEC budget. The AEC fission power program is not limited to the LMFBR. Other efforts are aimed at other breeders—the fast, gas-cooled reactor, the molten-salt breeder and the light water breeder. The first two are technology development efforts with modest funding. The light water breeder effort is aimed at an early demonstration of a prototype core for the Shippingport plant in Pennsylvania.

The AEC budget also includes a R&D program on the safety of current light water reactors. This program has been significantly expanded during the past two years to assure continuance of the excellent safety record of civilian nuclear power.

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TABLE 1.—*Federal energy R. & D. funding, fiscal years 1969 through 1973* [1]

[In millions of dollars]

	Fiscal year— 1969	1970	1971	1972	1973	1-year increase (percent)	5-year increase (percent)
Coal resources development	$23.3	$30.4	$49.0	$76.8	$94.4	22.9	305.0
Petroleum and natural gas	13.5	14.8	17.5	23.8	26.1	9.7	93.3
Nuclear fission:							
LMFBR [2]	132.5	144.3	167.9	237.4	261.5	10.2	97.4
Other civilian nuclear power [2]	144.6	109.1	97.7	90.7	94.8	4.5	−34.4
Nuclear fusion:							
Magnetic confinement [2]	29.7	34.3	32.3	33.2	40.3	21.3	35.6
Laser-pellet [2] [3]	2.1	3.2	9.3	14.0	25.1	79.2	1,095.2
Energy conversion with less environmental impact	12.3	22.9	22.8	33.4	55.3	66.0	350.0
General energy R. & D.	3.0	4.2	8.7	15.4	24.1	66.2	753.3
Total	361.0	363.2	405.2	524.7	621.6	[4] 18.4	[4] 72.2

[1] The funding listed in these tables cover the Federal R. & D. programs in development-exploration and production, conversion, and transmission of our energy resources. This funding includes energy conversion R. & D. for stationary applications only; R. & D. funding for improved mobile applications (e.g., automotive, rail, seagoing) are not included. Fundamental research on environmental health effects of combustion products and low-dose radiation exposure) is not included.

[2] This funding includes operating, equipment, and construction costs.

[3] The primary applications of the multipurpose laser-pellet effort are for other than energy production (see text).

[4] Average.

NOTE.—The totals in tables I and II differ from the earlier total reported at the time the fiscal year 1973 budget was released (p. 57, *the Budget of the United States Government for Fiscal Year 1973*). The data presented in tables I and II include additional budget components, viz., coal mine health and safety research is included in the Bureau of Mines budget and capital and equipment as well as operations are included in the Atomic Energy Commission budget.

TABLE II.—*Federal energy R. & D. funding,[1] fiscal year 1969 through fiscal year 1973*

[In millions of dollars]

	Agency	Fiscal year— 1969	1970	1971	1972	1973
Coal resources development:						
Production and utilization R. & D., includes gasification, liquifaction and MHD.	DOI–BOM	$12.3	$13.2	$15.4	$14.7	$19.0
	DOI–OCR	8.7	13.5	18.8	31.1	45.3
Mining health and safety research	DOI–BOM	2.3	3.7	14.8	31.0	30.1
Petroleum and natural gas:						
Petroleum extraction technology	DOI–BOM	2.6	2.7	2.7	3.2	3.1
Nuclear gas stimulation [2]	AEC	2.4	3.7	6.1	7.0	7.5
Oil shale	DOI–BOM	2.5	2.4	2.7	2.6	2.5
Continental shelf mapping	DOI–GS	----	----	----	5.0	7.0
	DOC	6.0	6.0	6.0	6.0	6.0
Nuclear fission:						
LMFBR [2]	AEC	132.5	144.3	167.9	236.6	259.9
	TVA	----	----	----	.8	1.6
Other civilian nuclear power [2]	AEC	144.6	109.1	97.7	90.7	94.8
Nuclear fusion:						
Magnetic confinement [2]	AEC	29.7	34.3	32.3	33.2	40.3
Laser-Pellet [2 3]	AEC	2.1	3.2	9.3	14.0	25.1
Energy conversion with less environmental impact:						
Cleaner fuels R. & D.-stationary sources	EPA	10.7	19.8	17.4	24.5	29.5
SO_x removal	TVA	----	----	----	2.6	15.2
Improved energy systems	HUD	.3	.8	3.0	2.4	2.8
Thermal effects R. & D.	EPA	.5	.8	.6	.7	1.0
	AEC	.8	1.5	1.8	3.2	[4] 6.8

Footnotes at end of table.

TABLE II.—*Federal energy R. & D. funding,*[1] *fiscal year 1969 through fiscal year 1973*—Continued

[In millions of dollars]

	Agency	Fiscal year— 1969	1970	1971	1972	1973
General energy R. & D.:						
Energy resources research [5]	NSF	--------	1.1	5.0	9.8	13.4
Geothermal resources	DOI	.1	.2	.2	.7	2.5
Engineering energetics research	NSF	2.9	2.9	2.7	4.0	4.7
Underground transmission	DOI	--------	--------	.8	.9	1.0
Cryogenic generation	NBS	--------	--------	--------	--------	1.0
Non-nuclear energy R. & D.	AEC	--------	--------	--------	--------	1.5
Total		361.0	363.2	405.2	524.7	621.6

[1] The funding listed in these tables cover the Federal R. & D. programs in development-exploration and production, conversion, and transmission of our energy resources. This funding includes energy conversion R. & D. for stationary applications only; R. & D. funding for improved mobile applications (e.g., automotive, rail, seagoing) are not included. Fundamental research on environmental health effects of combustion products and low-dose radiation exposure) is not included.

[2] This funding includes operating, equipment, and construction costs.

[3] The primary applications of the multipurpose laser-pellet effort are for other than energy production (see text).

[4] This entry includes $1,500,000 for dry cooling tower R. & D. under the AEC's new non-nuclear energy R. & D. category. Other related work is carried out under other civilian nuclear power.

[5] The NSF RANN program includes research on solar energy as well as fundamental energy policy studies.

Note: The totals in tables I and II differ from the earlier total reported at the time the fiscal year 1973 budget was released (p. 57, *the Budget of the United States Government for Fiscal Year 1973*). The data presented in tables I and II include additional budget components, viz., Coal Mine Health and Safety Research is included in the Bureau of Mines budget and capital and equipment as well as operations are included in the Atomic Energy Commission budget.

Legend: DOI—Department of the Interior, BOM—Bureau of Mines, OCR—Office of Coal Research, AEC—Atomic Energy Commission, GS—U.S. Geodetic Survey, DOC—Department of Commerce, TVA—Tennessee Valley Authority, EPA—Environmental Protection Agency, HUD—Housing and Urban Development, NSF—National Science Foundation, NBS—National Bureau of Standards.

Coal Research and Development

Although the Federal Government's energy R&D efforts began with coal well over a half century ago, this resource has until recently been supported as a poor stepchild. The Office of Coal Research (OCR), Department of the Interior, and the American Gas Association have jointly undertaken, subject to the approval of Congress, a $30 million accelerated pilot plant program for deriving high Btu gas from coal. The division of costs is two-thirds government and one-third industry. The program life of four years will lead to either a demonstration plant or, if feasible, direct commercial application. Three pilot plants associated with this program are in various stages of development. The first has already produced a small amount of gas. The second, is in its shakedown period. Groundbreaking for the third is scheduled for early summer of 1972.

OCR is also accelerating its R&D effort aimed at converting coal to clean fuel gases using combined cycles, clean liquid hydrocarbons, solvent refined coal, and the magnetohydrodynamic (MHD) generation of electric power.

The Bureau of Mines is conducting smaller scale R&D to extract high Btu gas from coal and to develop other clean fuels and MHD. The Bureau, as a result of the Coal Mine Health and Safety Act of 1969, increased its efforts on coal mine health and safety research by an order of magnitude in five years, approximately $30 million per year in FY 1972–73.

Closely related to Interior's work on coal mining and utilization are efforts by EPA and TVA to control air pollutants from coal and other fossil fuel combustion in stationary power plants. Nearly all of this effort has been applied to sulfur oxide controls, particularly by means of stack gas cleaning systems. The FY 73 budget includes a large increase to allow TVA to install a stack gas cleaning system on one of its large power plants and increases for EPA efforts on advanced, more efficient means for controlling sulfur oxides and other pollutants.

Nuclear Fusion Research

The AEC conducts the major portion of Federal research on controlled thermonuclear fusion. Its ultimate goal is to provide mankind with a new and different kind of energy source as the long term approach to the energy problem. Some of the reasons for pursuing fusion are:

(1) The possibility of unlimited low cost fuel—deuterium from sea water;

(2) Inherent safety against runaway reactions;

(3) Manageable radioactivity problems;

(4) High thermal efficiencies.

The fusion effort has been aimed at understanding the physics of plasmas and demonstrating the scientific feasibility of confining plasma long enough to produce useful amounts of energy. Most of this work involves magnetic systems for confining the plasma. Funding for this research has increased nearly 36%, or $10.6 million, in the five-year period.

In recent years, the use of high powered lasers to initiate the thermonuclear fusion reaction has been under study. It offers a possible additional approach to a fusion reactor, one which would supplement the three major magnetic confinement techniques now being studied. The multipurpose laser-fuel pellet effort has grown significantly in the last three years to over $25 million in FY 1973. Neither approach will see commercial use before the 1990's.

Petroleum and Natural Gas R&D

As mentioned previously, Federal efforts in petroleum and natural gas have been relatively modest in comparison with those of industry. The Bureau of Mines has long worked on oil shale and secondary petroleum extraction. The AEC's Plowshare Program has recently been directed almost exclusively at gas stimulation by nuclear devices. This technology offers a good deal of promise provided the related environmental questions are answered and objections to nuclear explosions are met satisfactorily.

Other Energy R & D Efforts

The National Science Foundation has for a number of years sponsored basic R&D on energy-related issues as part of its Engineering Energetics effort. With the establishment of the RANN (Research Applied to National Needs) Program, NSF's involvement has now moved from basic laboratory studies to advanced energy conversion systems such as solar power and policy studies related to energy and transmission systems research. The NSF's budget for energy studies has increased 31.2%, or $4.3 million, in FY 1973.

The Department of the Interior jointly sponsors, with the utility industry and through the Electric Research Council, an expanding program on underground transmission. It also has increased its efforts in the field of geothermal energy by 260%, or $1.8 million, in the FY 1973 budget.

The National Bureau of Standards and HUD also have expanded efforts involving civilian energy production and utilization.

Summary

The development of the technology to provide an adequate supply of electrical energy with minimal environmental impact is a critical factor in the nation's economic future. To attain that goal while simultaneously balancing energy needs and environmental concerns is a fundamental factor in the evolution of energy R&D programs. As presently constituted, that program has the following two salient components:

(1) A Federal energy R&D budget which has been growing at the compounded rate of 11% during the last five years;

(2) A pattern of funding which is continually being adjusted to reflect a realistic balance between domestic energy resources and the R&D required to utilize those resources most effectively.

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Appendix F

Chronology of the Mandatory Oil Import Program, 1959–73

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Chronology of the Mandatory Oil Import Program (MOIP), 1959–73

Phase of program	Presidential proclamations or Executive orders		
	Number	Date	Principal provisions
I. Establishment of the MOIP.	Proclamation 3279.	Mar. 10, 1959	Established program with stated national security objective. Defined districts I–IV (east of Rocky Mountains) and V (west of Rockies) as domestic crude-surplus and crude-deficit areas, respectively. Imports into districts I–IV set at 9 percent of total demand, those into district V at amounts needed to satisfy demand above domestic supply. Gave Secretary of the Interior authority to issue regulations and establish Appeal Board, plus redelegation authority. Made first attempt to define crude, unfinished oils, and finished products. Allocated quotas to refiners.
II. Implementation and adjustment.	Proclamation 3290.	Apr. 30, 1959	Excepted overland imports from quotas.
	Proclamation 3328.	Dec. 10, 1959	Canadian imports for districts I–IV were includable for calculating allowable imports. Extended Appeals Board's authority to cover finished product imports in hardship cases.
	Proclamation 3386.	Dec. 24, 1960	Increased flexibility of quota calculations on demand basis for each allocation period to allow variation of ± 9 percent of gap between allocations and actual demand for districts I–IV.

Chronology of the Mandatory Oil Import Program (MOIP), 1959–73—Continued

Phase of program	Presidential proclamations or Executive orders		
	Number	Date	Principal provisions
	Proclamation 3389.	Jan. 17, 1961	Changed allocation system for residual fuel oil to be used as fuel oil into district I (east coast), allocating between historical importers (1957 base) and importers/distributors at deepwater terminal in district I.
	Executive Order 11051.	Sept. 27, 1962	Involved Office of Emergency Planning (OEP) indirectly in MOIP on national security grounds and made Director of OEP Chairman of Oil Policy Committee to advise on further action.
	Proclamation 3509.	Nov. 30, 1962	Changed districts I–IV quota from 9 percent of demand to 12.2 percent of production. Redefined crude oil and introduced natural gas products.
	Proclamation 4531.	Apr. 19, 1963	Established the Appeals Board to consider petitions by persons affected by the regulations issued pursuant to sec. 3 of Proclamation 3531.
	Proclamation 3541.	June 10, 1963	Amended Proclamation 3279 to shift basis of quota from historical basis to one based on estimated future production, as determined by Secretary of the Interior for districts I–IV.
III. Use of MOIP for expanded objectives.	Proclamation 3693.	Dec. 10, 1965	Extensively amended Proclamation 3279. Authorized sliding-scale allocations to chemical firms having petrochemical plants in all 5 districts. Revised program for Puerto Rico to permit greater crude imports to the island as a means of stimulating growth of Puerto Rican refining capacity and eco-

			nomic development. Restricted imports into free trade zones (FTZ).
	Proclamation 3779.	Apr. 10, 1967	Freed asphalt of import restrictions.
	Proclamation 3794.	July 17, 1967	Began system of bonus-quotas of crude oil and unfinished oils for importers that manufacture in the United States, residual fuel oil to be used as fuel with a sulfur level acceptable to the Secretary. Redefined residual fuel oil, thus easing quota restraints on the latter. Also favored imports of low-sulfur fuel oil.
	Proclamation 3820.	Nov. 9, 1967	Instituted exceptions for Virgin Islands similar to those established in Proclamation 3693 for Puerto Rico.
	Proclamation 3823.	Jan. 29, 1968	Broadened Puerto Rican programs. Also brought liquids produced from tar sands under the MOIP to control importation of tar sand crudes from Canada.
	Proclamation 3969.	Mar. 10, 1970	Set fixed crude and unfinished oil quotas for Canada, to be chargeable to overall quotas for districts I–IV.
IV. Modifications necessary to meet the gap between domestic supply and demand.	Proclamation 3990.	June 17, 1970	
	Proclamation 4018.	Oct. 16, 1970	
	Proclamation 4025.	Dec. 22, 1970	All concerned with progressive increases in or exemption from quotas for various products and crude oil imported from various areas.
	Proclamation 4092.	Nov. 5, 1971	
	Proclamation 4099.	Dec. 5, 1971	

Chronology of the Mandatory Oil Import Program (MOIP), 1959–73—Continued

Phase of program	Presidential proclamations or Executive orders		
	Number	Date	Principal provisions
	Proclamation 4133.	May 11, 1972	
	Proclamation 4156.	Sept. 18, 1972	
	Proclamation 4175.	Dec. 16, 1972	
	Proclamation 4178.	Jan. 17, 1973	
	Executive Order 11703.	Feb. 7, 1973	Reorganized Oil Policy Committee, replacing Director of OEP with Deputy Secretary of the Treasury as chairman.
	Proclamation 4202.	Mar. 23, 1973	Broadened role of OIAB to handle growing numbers of requests for greater imports by easing criteria for allocations and removing limits on quota allocations allowable to OIAB.
V. End of mandatory import program.	Proclamation 4212.	May 1, 1973	Suspended the tariffs on imports of crude petroleum and petroleum products temporarily and instituted a license-fee system as a replacement for the quota system. Provided for certain fee-free allocations derived from the MOIP to be gradually phased out by 1980.

Source: U.S. Tariff Commission.