Final Report

THE IMPLEMENTATION OF A HYDROGEN ENERGY SYSTEM IN TEXAS

Project N/T-5

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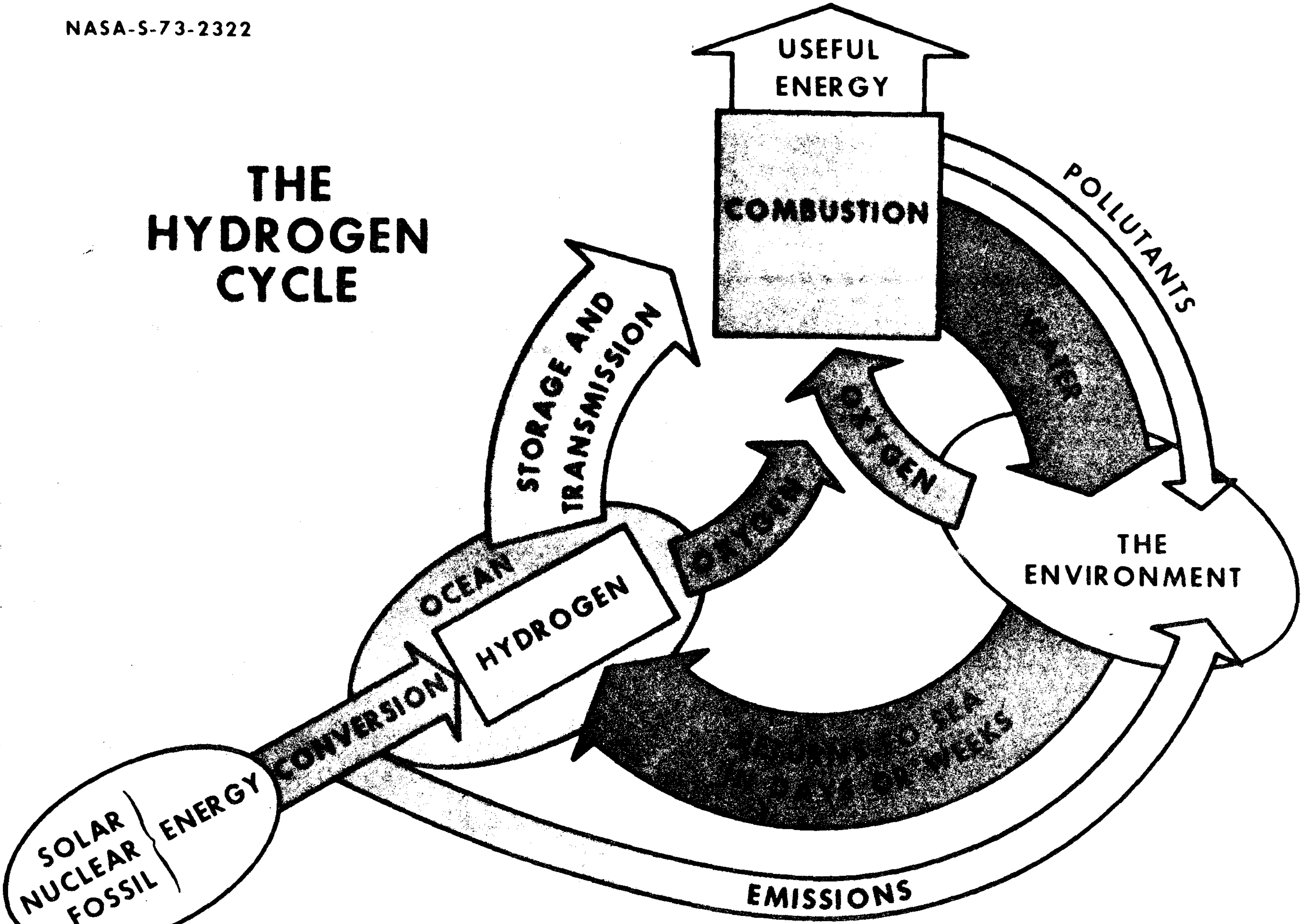
THE HYDROGEN CYCLE



(ADAPTED FROM FORTUNE)

I. Summary

Hydrogen has special advantages for Texas as both a fuel and a chemical feedstock. It can be produced from water or lignite, both of which are abundant in the East Texas and Gulf Coast regions. It seems based on the best present technical information, that existing pipeline systems can be used to distribute hydrogen.

Conversion of existing power plants, industrial fuel users, and many chemical process plants already using hydrogen, could be done immediately. This would have near-term impact on the demand for natural gas and other fossil fuels, which could be diverted to other uses.

Hydrogen has great advantages from the standpoint of environmental pollution at the point of use, but certain pollution problems remain at the point of production.

All technical problems involved in a hydrogen energy system appear within the bounds of reasonable solution. The implementation of a hydrogen system depends on the competitive position of fossil and nuclear energy, the projections of availability of these energy sources in the mid and far-term, and the legislative incentives and controls used to determine the future of the overall Texas energy system.

Economic incentives necessary to implement a hydrogen system that competes for a portion of the projected market for natural gas have been examined under various assumptions. Depending upon the Federal Power Commission's regulatory policies concerning the price of natural gas, the cost to the State of subsidizing the production of hydrogen to make costs competitive with natural gas could vary from a cost of almost two billion dollars over a five-year period under the worst conditions (FPC continuation of 1973 policies and extreme-high range predicted hydrogen costs) to a zero cost (possible $50 million profit for an industrial producer) for the same period under most favorable conditions (deregulation of natural gas prices and lowest predicted hydrogen production costs). These costs would result from substituting hydrogen for one percent of natural gas demand in 1977, increasing to five percent in 1982.

II. Why Hydrogen?

Hydrogen is technically attractive as an energy carrier for the following reasons:

1. When burned, the only product of combustion of hydrogen is water. Small amounts of nitrogen oxides are formed when the combustion is in air, but these oxides are easily kept to within acceptable levels.

2. Hydrogen is a gas and can be transported more cheaply over long distances than any other competing energy carrier with the single exception of natural gas. Line losses cause electrical transmission lines to be less efficient than piping hydrogen over distances greater than a few hundred miles.

3. Hydrogen is an excellent fuel, having wide flammability limits and very high energy per pound, and the lack of pollutants allows ventless furnace design. The latter point means that stack heat losses, which may be as high as 40 percent of the fuel energy, can be eliminated.

4. Hydrogen can be produced using solar, geothermal or nuclear energy.

The ability to substitute for or eliminate the use of fossil fuels in the long term is a major attribute of the hydrogen energy system.

In the long term the fossil fuel supply <u>will</u> dwindle, regardless of the particular predictions of energy supply/demand used. At that time, a supply of hydrogen easily distributed by pipeline and with all the advantages that natural gas now enjoys and more can be available. However, to have such a system available, it must be initiated <u>now</u>, even though it is not economically competitive in the present energy climate.

III. What are the Problems?

With all of the very real advantages of hydrogen, there are, naturally enough, some compensating disadvantages.

1. Hydrogen is not free, and it must be paid for in the cost of whatever energy form is used to produce it. However, almost any energy form, from nuclear to solar, can be used. In addition, hydrogen can be produced from plentiful fossil fuels including low-grade coal.

2. The cost of pollution control on the energy source must be borne by the hydrogen system. If lignite, for example, is used in a gasification plant to produce hydrogen, then costly pollution control must be invoked. The environmental impact is limited, however, to the production plant and none results at the use point. This is not true of competing conventional energy forms with the possible exception of electricity.*

3. Although hydrogen has high energy per pound, it is very light. Its energy per cubic foot, even in the liquid form, is low relative to other fuels. Therefore, its use where storage volume is important, such as in a transportation vehicle, is unlikely. Other synthetic fuels such as methanol or ammonia may be candidates to replace petroleum products in the far-term for transportation use.

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*With power plants often located in urban areas to avoid power transmission losses and programmed to burn coal or other fossil fuels, they might be viewed as having environmental impact at both the coal mine and the power plant. Hydrogen could be produced at the mine, and pipelined to the city.

IV. What about Texas?

In order to assess the impact of introducing hydrogen into the existing Texas energy system, we have made the following assumptions:

1. In the near-term, hydrogen cannot compete on an economic basis with the existing system except in certain special cases. Therefore, governmental incentives, regulations or controls will be necessary to initiate a hydrogen system.

2. Given assumption 1, those demand areas most amenable to State regulation are target areas for early changeover to hydrogen.

3. Technical ease of changeover also determines where hydrogen will be used. For example, regardless of State regulation, implementation of hydrogen for transportation systems will probably remain technically unreasonable.

4. Given assumptions 1 through 3, the areas of energy use can be examined for their possible conversion to hydrogen. These areas and the assessment of the conversion possibilities are given below.

   Residential - Commercial:
   Only through new communities such as Woodlands, or by very tough legislative action to stop or retard usage of existing energy systems. Large scale changeover not feasible in ten-year period. Reasons: can't be done gradually, since entire distribution system for natural gas within any metropolitan area is interconnected. Slowly increasing percentage of H_2 in a natural gas not feasible, because existing burners are not compatible with H_2. System would have to be completely shut down while all users were simultaneously converted to H_2.

   Industrial Fuel:
   Natural gas now provides 47% of national needs - probably more than that in Texas. Could be converted fairly cheaply and easily, but might require legislative incentives. Thirty percent of all fossil fuels are consumed nationally in this use. Changeover gives good environmental impact by reducing pollution.

Transportation:

Not much state impact - possibly long term uses in air and rail transport, but doubtful in ten years.

Electric Power Generation:

Almost completely changeable to H_2, with costs of burner and metering conversions perhaps offset by reduction in pollution control equipment. Because of local and state regulation available, this is probably best area for initial use.

Industrial - Chemical:

Major present uses are in production of ammonia and various hydrogenation processes. Supplies now come from natural gas. Thus, the hydrogen from the sources other than natural gas would make more of the latter available as fuel. Supply of hydrogen at competitive prices could be implemented immediately. Direct substitution possible.

IV.A. Recommended Order of Implementation

Immediate:

Industrial - Chemical

Short-term:

Electric power generation
Industrial fuel

Intermediate:

Residential - Commercial

Long-term or Inappropriate:

Transportation

IV.B. The Impact of Hydrogen on Supply/Demand

By the use of a computerized econometric model and an energy data base for Texas, the effect of introducing hydrogen into the Texas energy system can be forecast for the coming 10 year period. Details of the model are given in Appendix A.

Forecasts of hydrogen usage under different state policies are presented in the final section of this report, along with the impact on state usage of natural gas.

IV.C. Near-Term Production Methods in Texas

Hydrogen From Coal

From coal, we could synthesize gaseous or liquid hydrocarbons, if a source of hydrogen is available. Steam and heat (possibly from combustion of part of the coal) could be used to make hydrogen as shown in Figure 1. This process is less efficient than making methane from coal, as all the carbon in coal is rejected to the atmosphere as carbon dioxide. In addition, manufacture of hydrogen from coal has not been demonstrated fully on a commercial scale. However, the technology is similar to that of producing methane from coal and the feasibility of the process seems to be assured. In order to lessen the environmental impact of large scale strip-mining of coal, in situ gasification of coal may be used to produce hydrogen from a mixture of oxygen and steam or water pumped into a previously ignited coal seam as seen schematically in Figure 2. This method may be impractical for the relatively shallow lignite seams found in Texas.

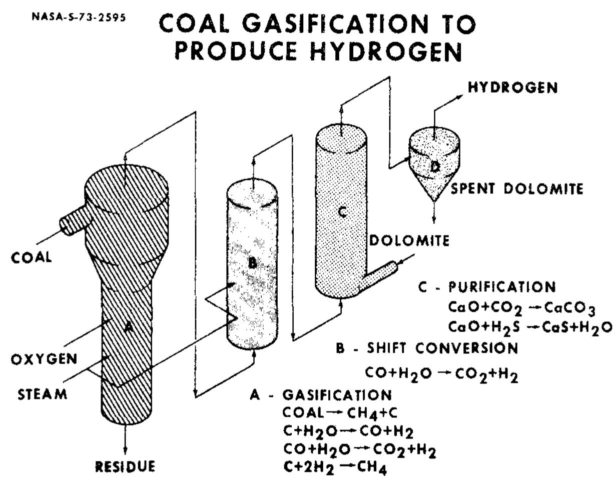

Figure 1 Coal Gasification to Produce Hydrogen

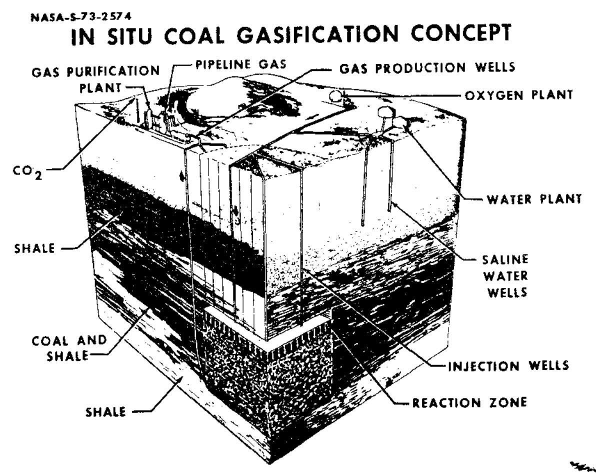

Figure 2 In Situ Coal Gasification Concept

Hydrogen From Nuclear Energy

The next alternative employs nuclear energy by one of two processes to produce hydrogen. A schematic of the path, nuclear power-electrolysis is shown in Figure 3. Treated water is electrolyzed by using low voltage direct current to obtain hydrogen. This process has been evaluated recently by the Synthetic Fuel Panel at Oak Ridge National Laboratory and by the Institute of Gas Technology. Basically, the cost of electrolytic hydrogen depends on the cost of electricity. Proponents of this system derive a low cost for hydrogen by the use of "off-peak" power from base load plants because intermediate and peaking plants supply the highs in electric power demand. In a large hydrogen economy, supplying 20 to 50 percent of the nation's energy requirements, it is difficult to foresee much "off-peak" power being available for electrolytic hydrogen. Rather, a dedicated nuclear plant for hydrogen production may be necessary to achieve low costs. Conventional electrolysers having conversion efficiencies of 60 to 70 percent are available today. Efficiency is the ratio of electric energy input to the heating value of the hydrogen output. This type of electrolyser suffers from high capital costs due to low current densities, typically 100 to 200 amps per square foot. Advanced concept electrolysers have been proposed and built by various companies (GE, Teledyne, etc.) based on NASA-derived fuel cell technology. Electrolysers of this type are capable of operation at higher efficiencies and current densities. Despite these improvements, the price of electricity is still the dominant factor in electrolytic hydrogen costs.

In a second type of process, water can be split by application of thermal energy or heat. One-step and multi-step processes for closed-cycle thermal decomposition of water have been proposed and tested. In the one step mode, the hydrogen produced from steam may be separated by means of a palladium membrane. Under equilibrium conditions, temperatures in excess of 2000°K are required for reasonable conversion of water to hydrogen. At Johnson Space Center, NASA is presently researching this process under non-equilibrium conditions at lower temperatures.

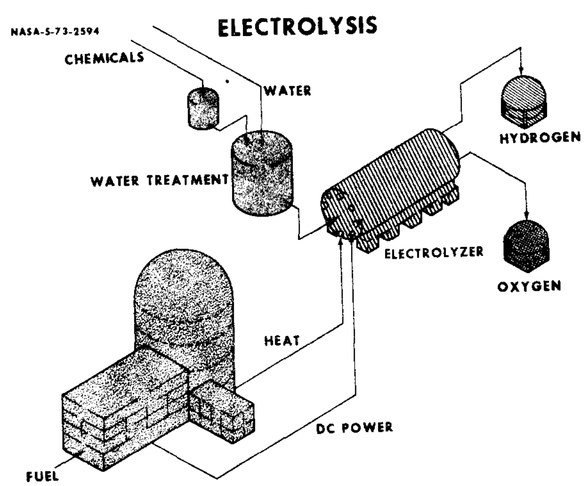

Figure 3 Nuclear Power - Electrolysis Schematic

IV.D. Hydrogen Production Costs

Although other methods of producing hydrogen may become preferable in the distant future, the two most likely methods of producing hydrogen in Texas initially are by electrolysis and by gasification of coal. For both methods the cost can only be estimated with the understanding that factors affecting these costs are subject to considerable uncertainty. Even so, these estimates can be of great value in considering energy for the future.

Cost of Producing Hydrogen by Electrolysis

Letting CP be the hydrogen production cost in $/million BTU, one research effort has estimated the following relation:

$$CP = 2.58\ ec + 0.4$$

where e is a measure of efficiency in the range 1.5-2.2 and c is the cost of electricity in ¢/kw-hr. This is based on information in the report by Michel [1][1].

A more optimistic estimate was made to arrive at the cost of producing hydrogen through the technology of solid polymer electrolyte electrolysis. Russell, Nuttall and Fickett [2], estimated that for 1985,

$$CP = 3.12c + .227$$

Improvements by the year 2000 would reduce the cost relation to

$$CP = 2.5c + .090$$

Here CP and c are defined as they were earlier.

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[1] Numbers in square brackets refer to references listed in Appendix C.

Cost of Producing Hydrogen from Coal

In the report by Michel [1] the cost of hydrogen production from coal has been estimated as:

$.78/million BTU from lignite at $2/ton

$1.32/million BTU from coal at $7/ton

According to this report the relation of hydrogen cost to lignite cost is:

$$CP = .12L + .54$$

where CP is the cost of producing hydrogen in $/million BTU and L is the cost of lignite in $/short ton.

The ASEE Summer Project [3] estimated the cost of hydrogen to run from $1.30/million BTU in 1975 up to $1.60 by 1995 (Figure 3-11, curve B, page 30 of the report). These figures take into consideration forecasts of the price of coal.

It is important to realize that there is considerable uncertainty in the future price of coal. To understand the effect of this price on the cost of hydrogen, we see that to produce one million BTU of hydrogen from coal requires:

a) .067 tons of bituminous coal, or

b) .089 tons of western (Wyoming type) coal, or

c) .125 tons of lignite

The production costs discussed above exclude the cost of transporting coal from the mine to the plant. The cost from Wyoming to East Texas is estimated to add somewhere between $.36 and $.62 per million BTU of hydrogen. While a plant in another part of Texas would have a different cost, this range reflects the uncertainty in rail rates and provides an indication of the effect of transportation. It is based on an estimated cost of 4 to 7 mills per ton-mile [4].

Hauser [5] has forecast the cost of Wyoming coal as:

Year	Cost/Ton
1972	$4.00
1975	$6.00
1985	$7.00 - 10.00
1995	$9.40 - 13.90
2000	$10.90 - 16.70

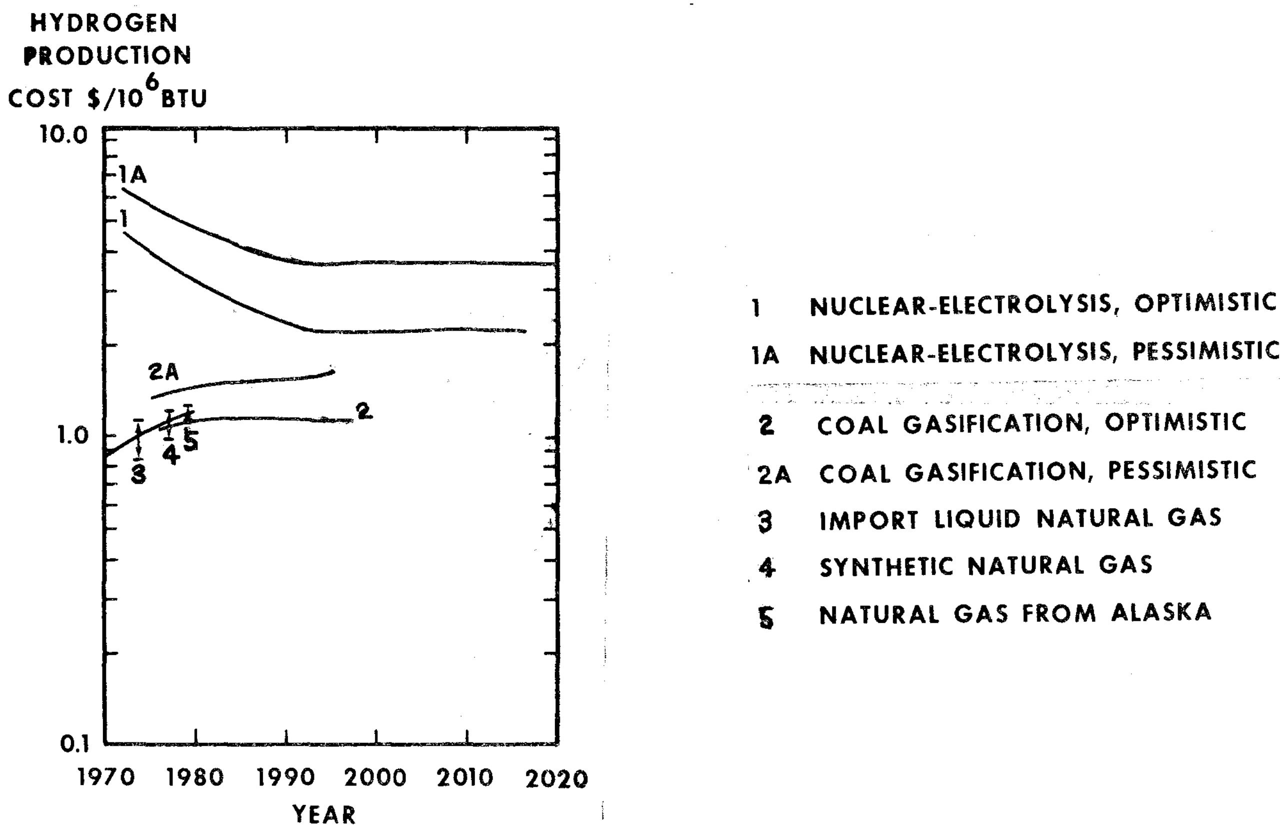


Figure 4: Projected Costs of Hydrogen and Other Gaseous Fuels [3].

IV.E. Distribution

Proposed methods for the production of hydrogen will result in gaseous hydrogen which must be transported from the production location to the user. The results from this study show that, while some problems must be overcome, there is no reason why hydrogen should not be distributed in much the same way that natural gas is distributed today. Underground pipelines should provide most of this distribution capability. Trunk pipelines already exist throughout Texas for transmission of natural gas, and similar networks of underground hydrogen-gas pipelines certainly are within the realm of feasibility. This report presents a summary of research into the question of a hydrogen distribution system for Texas. Technical details have been omitted, since they are available in the references.

The Existing Natural Gas Pipeline System

Essentially all the natural gas used in Texas today is delivered by gas pipeline. This transmission system is quite efficient, especially when compared with alternate transmission methods. A hydrogen gas system undoubtedly would be similar to the existing natural gas pipeline system, since the present users of natural gas also would be potential hydrogen users.

Texas has an extensive natural gas pipeline system in existence today. This pipeline system is most widespread throughout the Gulf Coast area, although it also links the major metropolitan areas. Initially, it may be economical to adapt some portion of the existing system to a hydrogen system, if further investigation shows this to be technically and economically feasible.

A recent study [6] showed that most petrochemical plants (a prime potential user of hydrogen) in Texas received their feedstocks by pipeline. "This method is used far more frequently than any other, with 67 of 68 firms interviewed receiving a portion of their raw materials by pipeline. Forty-two firms received more than three-fourths of their raw materials by pipeline, while 14 firms use the pipeline for all their supply." ([6], p.45). Since most of these petrochemical plants are along the Gulf Coast, most of the pipelining is in the same areas.

A Hydrogen Pipeline System

The development of a hydrogen pipeline system can come about in several ways, although the details need to be developed in a separate study. Presumably, some of the existing natural gas pipelines will be incorporated into the hydrogen network. Just what portions of the existing pipeline would be needed will depend upon the locations of the hydrogen plants with respect to the users of the hydrogen. The feasible areas for hydrogen plants with appear to be central Texas (close to the lignite deposits) and the Gulf Coast (close to water). Either location would be easily accessible to the existing pipeline system.

In a study of the hydrogen transmission requirements, Gregory and Wurm [7] determined that about three times the volume of hydrogen is required to be transported for the same energy content as natural gas. Hydrogen has only one-third of the heating value per cubic foot of natural gas. Existing natural gas pipelines could be used to transmit an equal amount of energy in the form of hydrogen gas, but such a system would require approximately four times the present compressor capability and over five times the compressor horsepower. Such a conversion, however, probably would be more economical than the construction of a wholly new pipeline system.

Safety

Hydrogen has been used in industrial applications for years, yet there still is some concern regarding safety of the pipeline system. This does not appear to present a problem when proper precautions are used. Industrial experience has been summarized as follows ([8], p. 1341):

1. Gaseous and liquid hydrogen can be handled safely for commercial applications.
2. Existing specifications, regulations, and standards are adequate for use as a base for expanding the application of hydrogen.
3. Safe operation of hydrogen facilities requires trained, competent personnel.
4. Safety can be improved further by:
    a. Thoroughly understanding the functional requirements of the entire process when designing and manufacturing components that are to be integrated into an operating system.
    b. Employing materials and equipment that minimizes leakage of hydrogen to the atmosphere.
    c. Control the rate and location of hydrogen venting to the atmosphere.
    d. Develop monitoring equipment for fast, accurate surveillance of the process equipment.

The use of hydrogen as a primary fuel will necessitate the development of large-scale transmission and storage systems. Development and implementation, of necessity, would be accomplished over a number of years and in a planned and logical sequence. Hydrogen use as an industrial fuel would be among the first stages of implementation with petrochemical plants in Texas probably being among the first users of hydrogen. These petrochemical plants exist in close proximity to the existing natural gas pipeline system along the Gulf Coast, so a natural implementation step might be to convert portions of the existing pipeline system to hydrogen. Further detailed studies, of course, would be required to verify these findings.

V. What is the Forecast Climate for Hydrogen in Texas?

Energy has traditionally been cheap in the United States because sophisticated technology has been aimed at producing it, and fossil fuels have been relatively easy to obtain. Texas has prospered because of this.

This climate will continue for some indefinite period. But forces are at work now to change it, and it will end altogether when fossil fuels become so scarce that their price becomes unacceptable. In the meantime, certain trends can be seen that will affect the energy picture in Texas.

V.A. Forecast Legal Climate

Cady [9] has reviewed recent legal decisions with possible applicability to present and future use of large-scale hydrogen energy systems. Many of these apply to Texas. Some of his insights and conclusions are:

1. Recent antitrust decisions, if applied to the degree possible and even likely, may cause the dissolution of the large horizontally and vertically integrated energy companies. Because these companies are virtually the only ones in the private sector able at present to make large capital investment, these decisions may significantly hinder private entry into the hydrogen economy.

2. Existing eminent domain and condemnation law, coupled with environmental considerations and large requirements for water, may cause land-sited hydrogen production to be at a disadvantage with off-shore plants.

3. Regulation of safety, price, environmental protection and even workman's compensation for the energy sector is rapidly being pre-empted by the federal government at the expense of state regulation. In the period of a hydrogen economy, such federal regulation will probably be complete.

4. International Law shows trends which may require stringent safeguards for offshore nuclear/hydrogen plants as well as the sharing of the benefits of such plants with other countries.

To quote part of Cady's conclusions: "As current, intermittant energy shortages grow into future chronic shortages, the law of the American energy system will change. The new law will be a law of energy scarcity. The new law will essentially foster limitation and conservation. It will be rigid, tight, need-oriented; a single, comprehensive, federalized, bureaucratic-administrative system of law. In short, it will be a law of allocation well suited for an essentially managed economy."

V.B. Remaining Technical Questions

No insurmountable technical problems appear to remain for the implementation of a hydrogen energy system. Production by coal gasification is less complex than the reasonably well-developed systems being tested for production of synthetic natural gas. Production by electrolysis is a well-developed process in industry, although improvements in efficiency would be desirable.

The chief unknown is the possibility of the embrittlement of pipeline steel in a hydrogen environment at pipeline pressures. This question must be answered before large scale use of existing pipelines for hydrogen can be considered.

Research on less expensive production methods, the so-called thermochemical decomposition methods, should be carried forth. These offer the very real possibility of low-cost hydrogen in the mid-term.

VI. Possible Approaches to Implementation

Because it will probably be necessary to provide artificial incentives to the initial production of hydrogen in Texas, the effect of various legislative alternatives can be examined. These alternatives are:

1. Subsidies, tax advantages or other means of encouraging hydrogen production at prices competitive with competing fuels.
2. Taxation or regulation of other energy sources to price them above hydrogen for selected usage.
3. Allocation of fuels to certain uses by legislative control so that hydrogen can be implemented in a way that will be most effective in saving natural gas and other fossil fuels.

VI.A. Scenarios for Texas

It is assumed here that a favorable policy for long-range implementation of hydrogen production and distribution is in the best interest of the State of Texas. Given this assumption, we now proceed to examine alternative policies for such implementation, and the relative costs of these policies.

Technical Alternatives Based on the information in Sections IV.C. and D., we have chosen two alternatives for hydrogen production and the location of the production plants.

Alternative 1: Gasification of lignite, with the gasification plant sited on or near the lignite deposits in East-Central Texas.

Alternative 2: Electrolysis of water by a dedicated nuclear plant, sited offshore in the Houston-Galveston-Freeport area.

These sites are chosen to minimize transportation costs, as both are situated near major termini of the existing pipeline system in Texas. Both plants are near the primary Texas petrochemical/power consumption center in the Houston-Galveston-Texas City-Freeport area, where initial customers for hydrogen are expected. An existing hydrogen pipeline presently serves the Houston petrochemical complex. This line is operated by Air Products and Chemicals, Inc. and is run at relatively low pressure (200-250 psi).

The two production alternatives use existing technology, and could presumably be bid by a number of firms at the present time. This is not to say that the plants are off-the-shelf; rather, they combine a number of facets that are individually available, but together have some technical risk. For example, offshore nuclear plants have been designed, but not actually built; electrolysis plants are in operation in Europe, but not using advanced electrolyzers, and not in conjunction with nuclear/electric plants; hydrogen pipelines are in operation, but over relatively short (350 Mile) distances and low pressures. Putting together an offshore nuclear-electric electrolysis plant for pipelining hydrogen thus has some risks.

VI.B. Natural Gas Scenarios

<u>Economic Analysis</u> A computer model is implemented on the UNIVAC 1108 of the University of Houston. It tests the economic feasibility of a partial conversion to hydrogen of specific sectors of the economy in Texas in the short run. It ties the economics of hydrogen to alternate price policies in the natural gas economy.

<u>The Natural Gas Situation</u> The first step is to study the natural gas situation, and to estimate its evolution throughout the

decade 1973-1982. Thus a natural gas model was implemented. The MacAvoy - Pindyck natural gas model was chosen. This national model, written at the Massachusetts Institute of Technology, was specifically adapted to Texas; specific regressions were conducted on cross-sectional time-series by year (1968-1972) and Texas Railroad Commission district (TRRC).

A detailed presentation of the MacAvoy model may be found in the literature [10]. Some minor adaptations were necessary to implement this model for Texas and make possible the connection to the hydrogen minimodel. A listing of the main equations, as implemented for this project, can be found in Appendix A, together with a simplified flow-chart of the model.

<u>The Implementation for Texas</u> The model was tested over the historical period (1968-72) by TRRC district for supply variables. Demand variables were regressed using Texas, Louisiana and New Mexico data to provide enough values (only data by state were found to be available).

Some significant differences have been found in the regression analysis between the Texas situation and the nation's situation as explained by MacAvoy in his nationwide model. Roughly speaking, the situation in Texas seems to be slightly more critical than it is nationally (for instance, for the production/reserve ratio). The high findings in the first half of the century might have encouraged a more intensive exploration of Texas gas fields in comparison with national resources.

The model was implemented for interactive experimentation. The interactive features are also presented in Appendix A along with a simplified flow-chart of the interaction and list of the exogenous variables.

Through extensive use of the model, it was found that the natural gas situation in Texas is highly sensitive to exogenous variables such as the FPC controlled wellhead price of natural gas.

Typical Scenarios It appears that the main factor conditioning the natural gas situation is the FPC price policy. A variety of hypothesis upon other exogenous variables, in particular upon demand growths, were taken with more or less influence over the model's prediction. Average values, rather than extreme cases were retained to concentrate the study on the FPC controlled price, which is the most easily controllable exogenous variable.

Three clear-cut scenarios were retained:

I. Continuation of the 1968-71 strict control of gas prices (1 or 2 cents increase per year in real terms)

II. Liberalization (progressive) of gas prices (+7.5% in real terms, per year)

III. Deregulation of gas prices: 100% increase in 1973, followed by a 30% increase in 1974, followed by a 1% increase over the rest of the decade.

The model was then executed over the period 1973-1982 for these three scenarios, and the results were compared.

Definition of the Main Variables A succinct definition of each of the variables in the model may be found in Appendix A. A careful analysis of the main results requires some care in the interpretation of the exact significance of the variables involved.

1. The wellhead price is the FPC regulated wellhead price. It is not the average wellhead price, since a part of the market is intrastate and thus does not

fall under F.P.C. regulation. No attempt was made to estimate what would be the impact of state control over intrastate deliveries. On the contrary, the model assumes that the ratio between the controlled portion of the market and the overall market remains the same throughout the decade as it was during the historical period.

2. The wholesale price is an average wholesale price over all sectors of demand, and over the whole state of Texas. It can be noted that the variations are important both between sectors and geographic locations in Texas. A $1.00 average wholesale price may mean a $2.00 price on the residential sector, which may be $2.50 in some places in Texas less controlled by F.P.C. regulations. In effect, the wholesale price outputted by the model must be considered more for its comparative value between different scenarios than for its absolute value.

3. What is called "shortage" carries little absolute meaning since Texas is a high exporter of natural gas. But no attempt was made to model the nation's natural gas demand, and thus a hypothesis about exports was retained. Exports were supposed to constitute a constant proportion of total production, the constant being obtained by statistical analysis over the historical period. Thus the "shortage" is the difference between demand and supply that would occur if the trends about interstate exchanges remain constant throughout the decade.

4. Production figures are net figures as defined by the U. S. Bureau of Mines.

5. Reserves do not have the meaning of ground resources. The model does not attempt to estimate Texas resources at all. Year-end reserves are precisely defined to be the amount of natural gas that drilling industry holds (i.e., already drilled) which are not yet exploited (i.e., released as production).

6. "New discoveries" do not represent the totality of what adds up to the year-end reserves of drilling industry. As shown in the flow-chart, additions to reserves include:

    1. New discoveries
    2. Extensions of previous discoveries
    3. Revisions of previous estimations

   However, new discoveries are shown rather than additions to reserves, because extensions and revisions are really the function of "new discoveries" for previous years, and thus new discoveries are more indicative of the trends in natural gas findings.

Analysis of the Results for Natural Gas Tabulated results corresponding to the three base scenarios taken, are found in Appendix D.

In the analysis of such results, one must not forget:

1.-the level of the other exogenous variables. In particular, we assume that there is no "drastic" shortage of overall energy in Texas during the period, and that alternate fuels are still available, making demand strictly a function of fuel relative costs. Zero growth in electrical generation, or big increases in oil prices affect substantially the quantitative results although the qualitative effect of alternate gas prices is fairly constant whatever the other exogenous variables may be.

2.-That we are assuming essentially that trends of the period 1968-72 prevail over the entire decade. Coefficients regressed for the period 1968-1972 were thus supposed to be valid for the rest of the decade. On the other hand, certain coefficients resulting from the regression analysis were kept even when they were not statistically significant, particularly coefficients supposed to estimate long-term trends, because of the economic significance attached to them.

In general, it should be kept in mind that the results of this model carry a meaning which is more qualitative than quantitative, proper to be compared rather than as absolute predictions.

Demand figures are found to be the most inelastic to alternative gas price policies. On the other hand, they are very dependent on overall energy growths per sector. No attempt was made to measure the impact of the shortage over the demand, since shortage is really a function of interstate exchanges. It is reasonable to think that in the case of a real shortage, demand may partially turn to alternate energy forms, even if they are more expensive. However, qualitatively, the higher gas prices are, the lower the demand, which might be expected.

Discoveries, on the other hand are very sensitive to gas prices, though with a time-lag of two to three years. Discoveries are explained in the model by the identity:

Discoveries = Number of wells drilled x Average discovery per site.

Higher drilling cost trends have a weak negative impact over the number of wells drilled, and the level of revenues from gas and oil sales have a strong significant effect upon the number of wells drilled, as might be expected.

The average discovery size was also found to be positively sensitive to higher gas prices. This effect is more difficult to explain, but referring to Mac Avoy, we might distinguish between

- intensive drilling, which is drilling in places where probability of a discovery is big (i.e., at the edge of already exploited fields) but where the average discovery size is weak.

- extensive drilling (i.e., offshore or great depth) where probability of a discovery is weak (many dry holes) but possible findings were important.

Given big revenues from high production, drillers would tend to practice high risk drilling (extensive drilling), whereas they cannot take the risk in the hypothesis of low gas prices.

Together, these two variables (number of wells drilled, average discovery size) show a strong significant effect of higher gas prices, but with a significant time lag.

Production is expected to grow quicker than discoveries for increases in prices of gas. Higher gas prices encourage drillers to sell more out of their reserves, hoping that the additional cash flow will permit them to recover more in subsequent years.

Reserves are important, since they explain how "healthy" the financial situation of the drilling industry is. The numerical impact of policy upon reserves is relatively small. Higher gas prices yield more additions to reserves, but also are an incentive to produce more, and these effects partially cancel out. In almost all cases generated, the tendency of decreasing reserves existing since 1968 continue throughout the decade. It takes an extreme case of deregulation of gas prices and oil prices ($6 a barrel at wellhead) to bring back reserves in 1982 to their level of 1966. In most other cases, reserves fall in 1982 to from one-half to one-third of their 1966 level.

However, the tendencies for the middle run appear to be quite different with gas price policies. The long-term effect of bigger cash flow upon addition to reserves is to be felt after this decade, whereas the production level is bound to prices only in the short run.

Shortage is positive in 1982 whatever gas prices, for the values of demand growth taken. Higher gas prices only bring a temporary relief to raise production to the level (or above) of the demand in the short run, but this production, coming mainly out of already existing reserves, does not continue in the long run.

A few qualitative conclusions may be taken:

1.-There will be a "shortage" of natural gas (as defined by the model) before the end of the decade.

2.-The tendency of overproduction (produce more than is discovered) is going to persist throughout the decade.

3.-The assertion "there is no more gas in Texas" must be related to a price level. What is meant is not that the general tendancy of decreasing gas resources can be overcome, but that higher gas prices do help drilling industry to recover more gas by permitting them to effectuate risky operation and use expressive technology.

4. -Higher gas prices may contribute to reducing the shortage (whatever the actual value of the shortage is) in the short run.

Figures 5 through 8 detail the results of the three scenarios upon which the hydrogen predicitons are based. The scenarios, as outlined before, are:

I. Continuation of present FPC pricing policies, giving very low rate of increase of present natural gas prices.

II. Progressive liberalization of gas prices at a rate of 7.5% per year.

III. Deregulation of gas prices, allowing a 100% increase in 1973, 30% increase in 1974, followed by a one percent per year increase from then on.

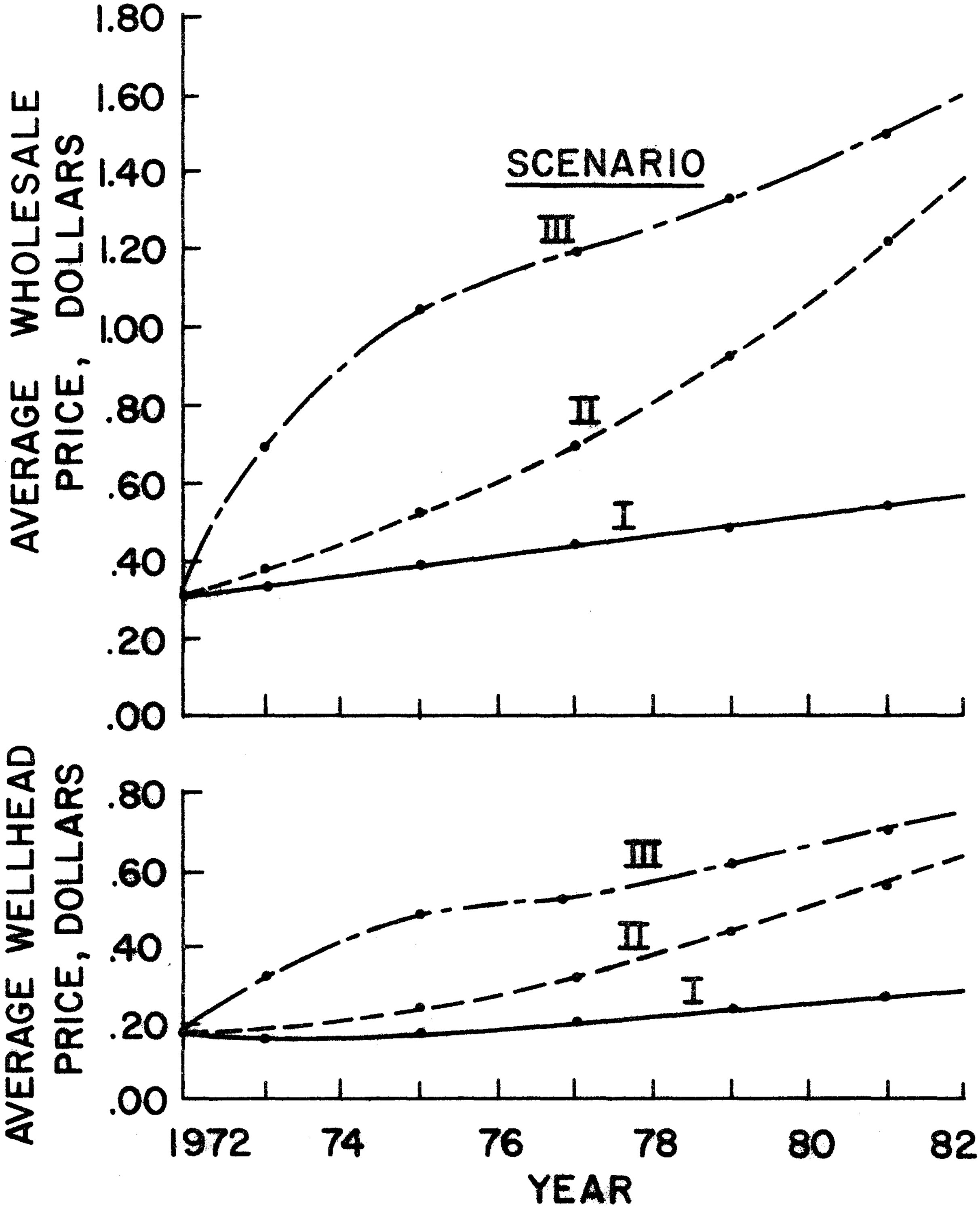


Figure 5. Forecast Wholesale and Wellhead Price of Natural Gas

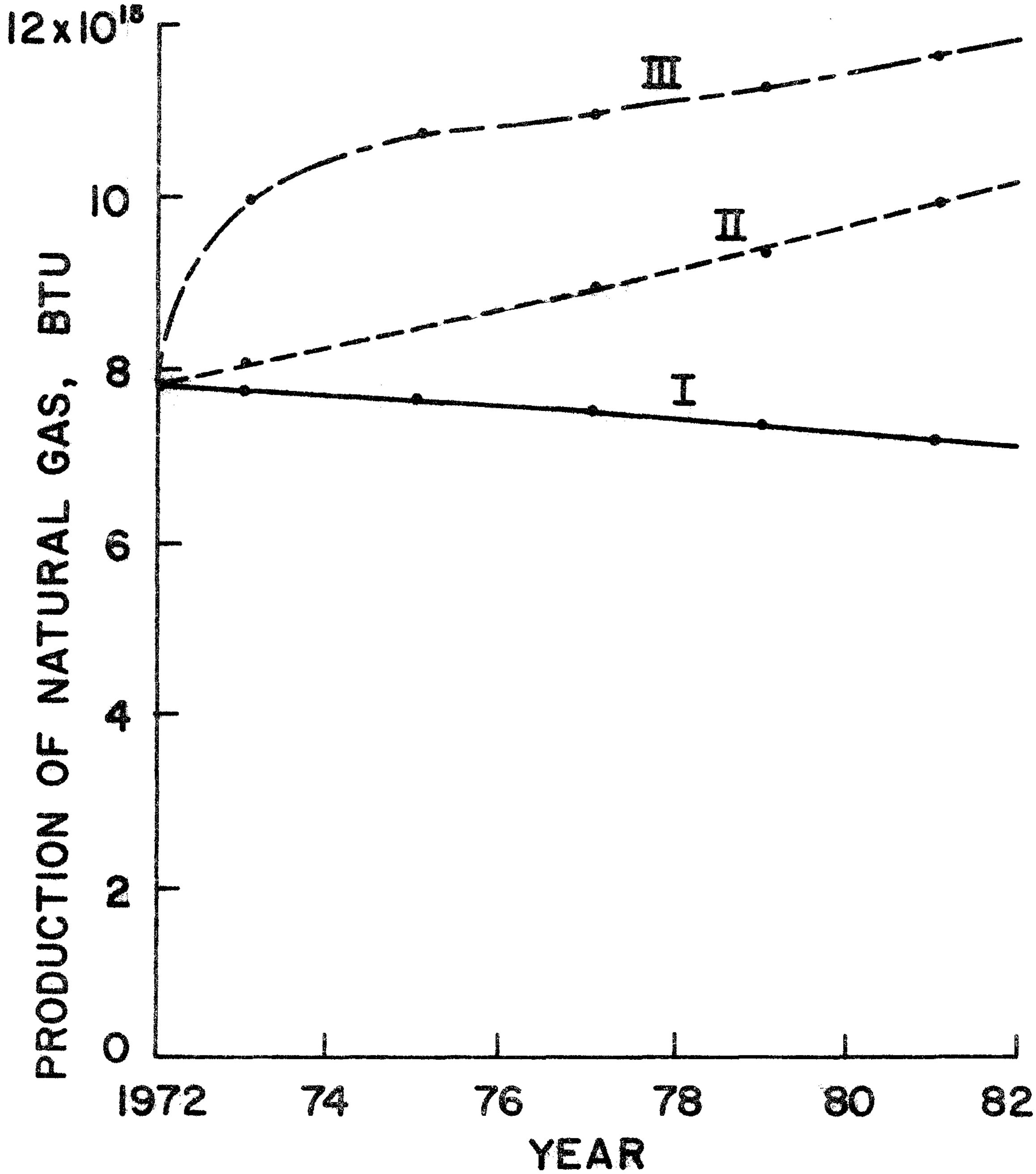


Figure 6. Forecast Production of Natural Gas

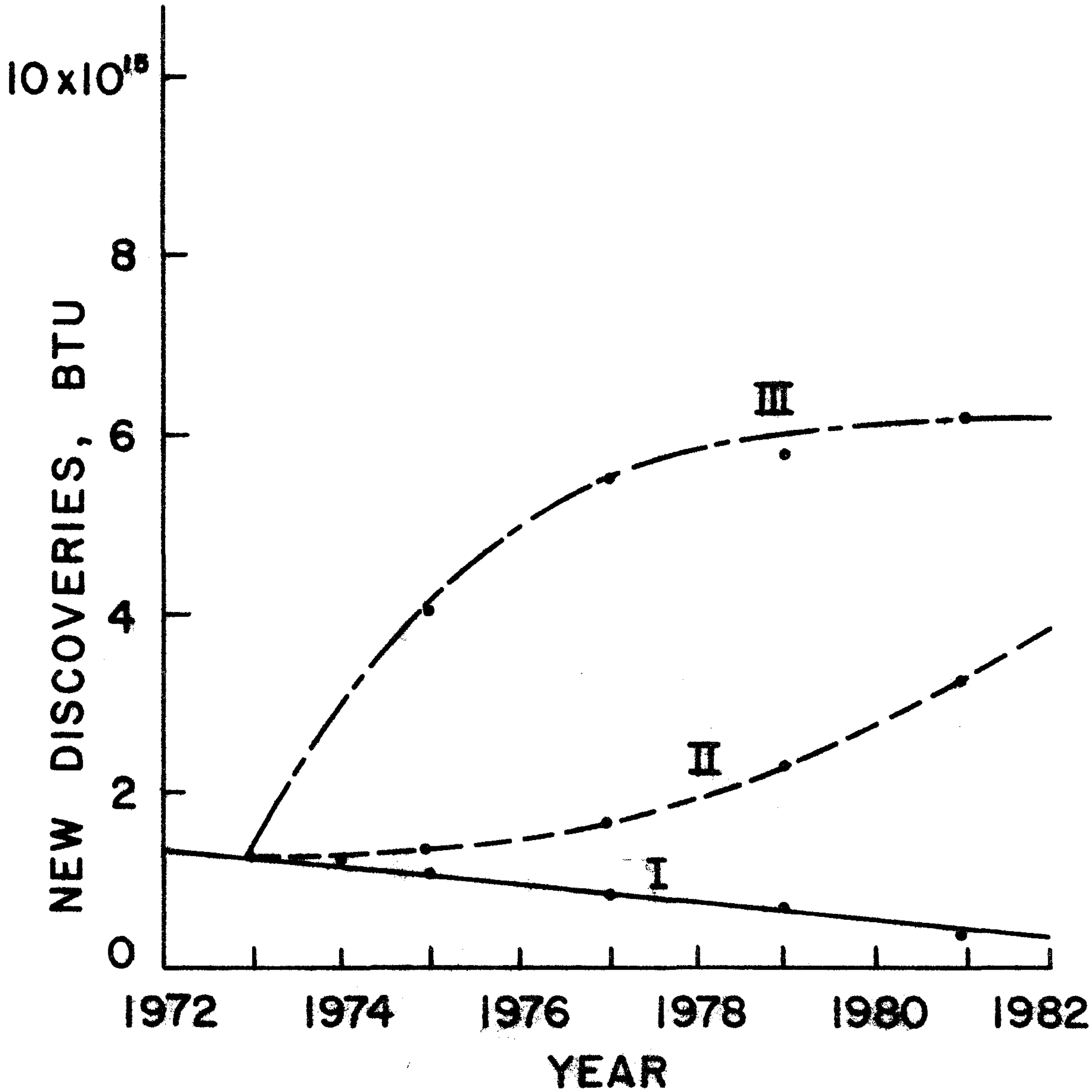


Figure 7. Forecast New Discoveries of Natural Gas

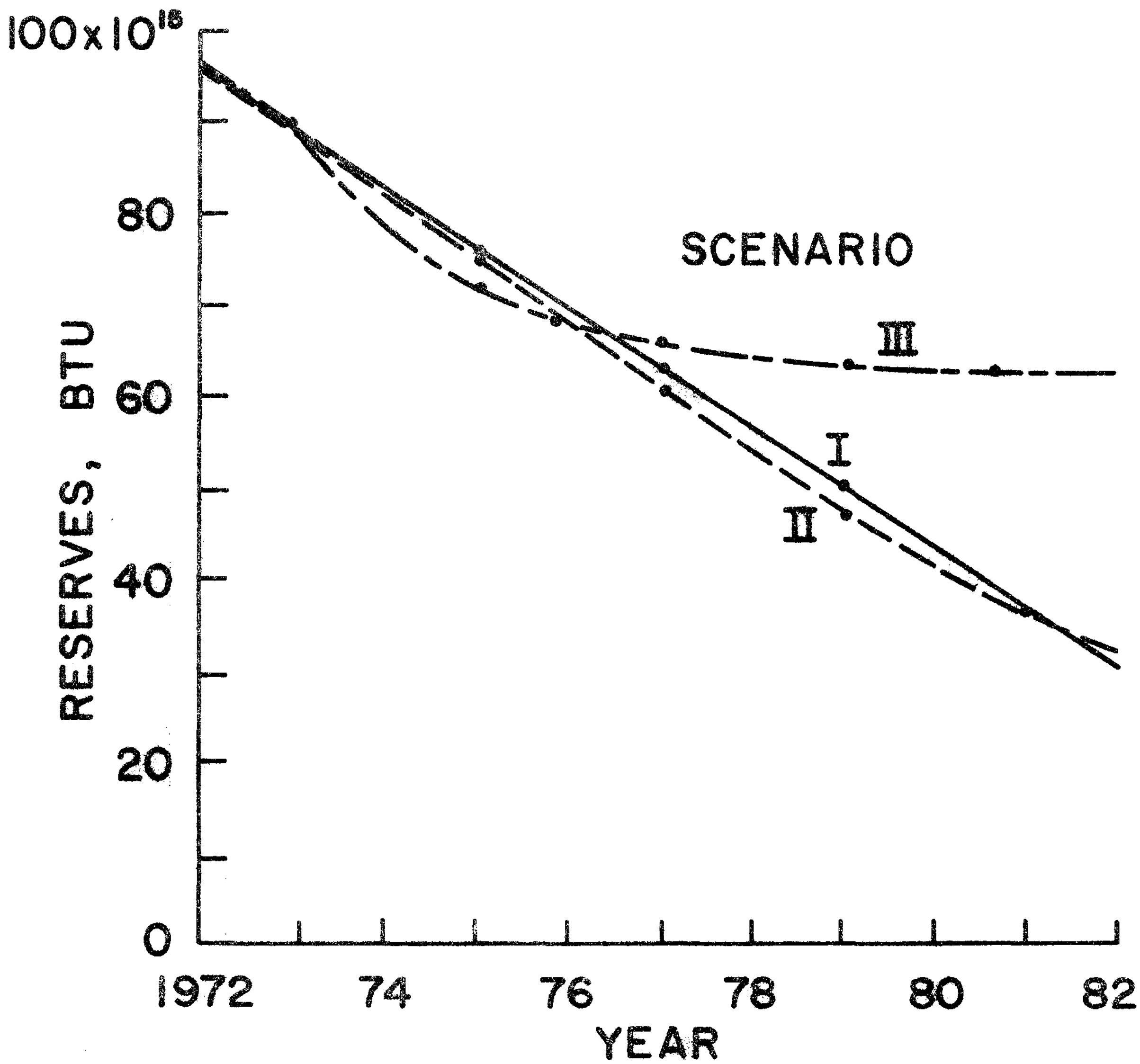


Figure 8. Forecast Reserves of Natural Gas

VI.C. Scenario For Hydrogen Implementation

The presence of a shortage (small) throughout the decade, and more importantly, the tendency of the natural gas situation make necessary the promotion of an alternate energy carrier.

A free market for hydrogen, considered directly competitive with natural gas, would yield a prediction of quasi-zero hydrogen production throughout the decade. This fact is undoubtedly true in the short run, because of the historical low-price policy for natural gas and the possibility of recovering still more gas out of the ground at prices cheaper than the methods for producing hydrogen. But tendencies show that in the long run, hydrogen might become competitive, and can be produced from other non-fuels.

Thus it appears it might be worth a financial commitment to promote hydrogen in a specific sector and geographical location in Texas, before the end of the decade. This would have the following advantages:

1.-Provide an experiment

2.-Contribute, however little, to reducing the present shortage

3.-Prepare a background for a switch to a hydrogen-based economy, in provision of future important shortages.

The scenario supposes that:

The State issues an invitation for proposals for the construction of a power plant to be implemented in a specific geographical location, and using a specific production technique. Some cost would be proposed over the life of the contract, and the benefit to the industry would come from the ability to keep prices under the state's estimate. In exchange, the state would guarantee to subsidize, for a specific production, the difference between hydrogen and a price indexed on local natural gas prices. So the problem for the state is to minimize the necessary subsidy over the contract life.

The policy factors are:

- choice of the technology (gasification, electrolysis...) fixing the different parameters concerning a cost curve

- choice of the site (East-Texas, West-Texas). The choice of the site may have an impact on: (1) competitive prices of natural gas (local prices may be higher than Texas average); (2) presence of a huge demand at proximity, to minimize transportation costs.

- action over the demand by determination of the price local industries are ready to pay for hydrogen. This is bound to natural gas prices (and so bound to the site chosen), but can also be controlled by various state incentives (such as pollution control requirements).

- direct action upon competitive natural gas prices by changing regulatory policies on natural gas (i.e., FPC controlled wellhead gas price).

Results for the hydrogen model are shown in Figures 9-14. Hydrogen production costs are taken at \$1.00, \$1.75 and \$3.75 per million Btu's initially, with varying rates of increase due to fuel cost increases, and with decreases in cost for increasing production rates.

Results are shown for various hypothesis as to user acceptance. Shown are cost of production, wholesale price, amount of production and the cumulative amount of subsidy required to compete directly with natural gas.

Table VI-I outlines the parameters of the model.

TABLE VI-I

HYPOTHESIS FOR HYDROGEN MODEL

Initial Year	1977 for all runs
Demand Coverage, Initial	1% for all runs
Final Year	1982 for all runs
Demand Coverage, Final	5% for all runs
Initial Cost/1972	\$1.00 (runs (1) to (4)) \$1.75 (runs (5) to (8)) \$3.75 (runs (9) to (12))
% Increase per year of input fuel	+ 10% ((1)-(4)) + 5% ((5)-(8)) + 0% ((9)-(12))
% Decrease per year for 100% increase in prod.	+ 5% ((1)-(8)) + 15% ((9)-(12))
Losses (percent of total prod)	20% for all runs
Transportation cost index (natural gas = 100)	260 for all runs
Local index of natural gas prices	120 for all runs
Percentage users willing to switch for equal prices	90% runs (1)- (2) runs (5)- (6) runs (9)-(10)
Average User Price: 101 ((1)-(2)-(5)-(6)-(9)-(10)) 125 ((3)-(4)-(7)-(8)-(11)-(12))	75% runs (3)- (4) runs (7)- (8) runs(11)-(12)

Natural gas prices + 1.0% deflated/year (1)-(3)-(5)-(7)-(9)-(11)

+ 95.6% in 1973
+ 35.5% in 1976 deflated, (2)-(4)-(6)-(8)-(10)-(12)
+ 1.5% later

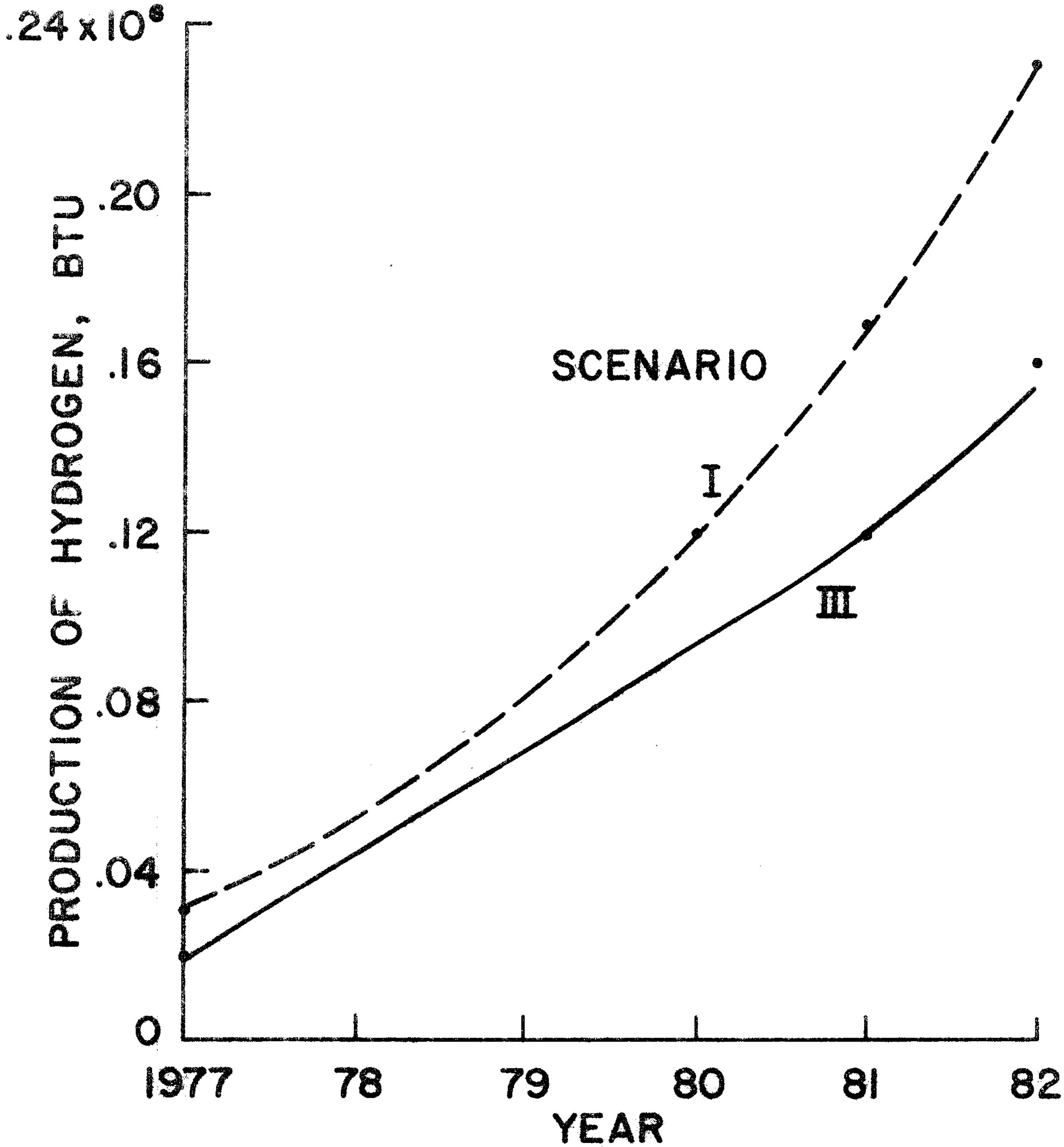


Figure 9$_6$ Forecast Hydrogen Conditions for Initial Cost of \$1.00/10 Btu, with 10 percent/yr. Increase in Fuel Cost and 5 percent decrease in price for 100 percent increase in production. Users pay price equivalent to Natural Gas, with 90% of Users Switching if Prices Equal a. Production

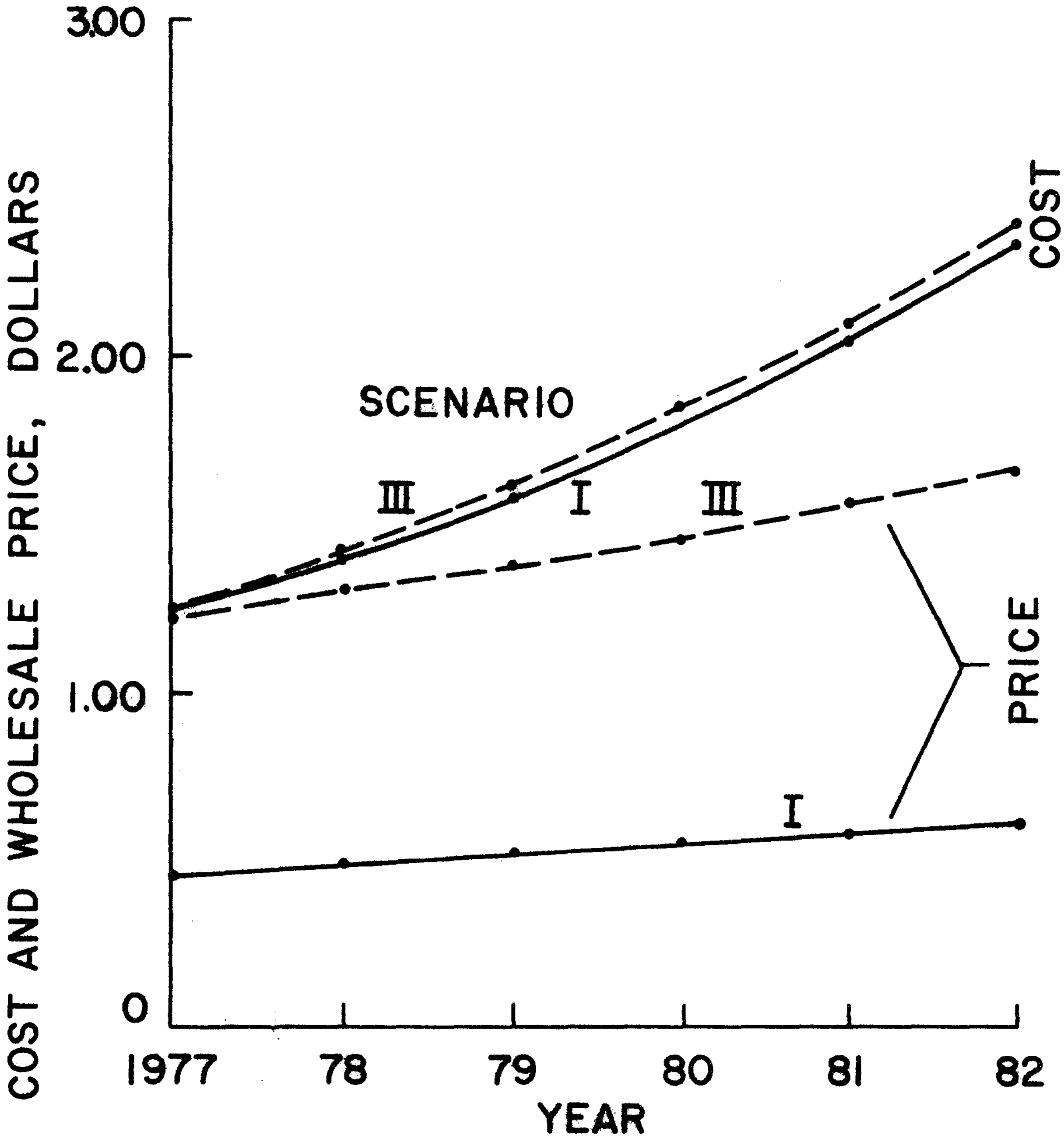


Figure 9. (continued). b. Cost and Wholesale Price

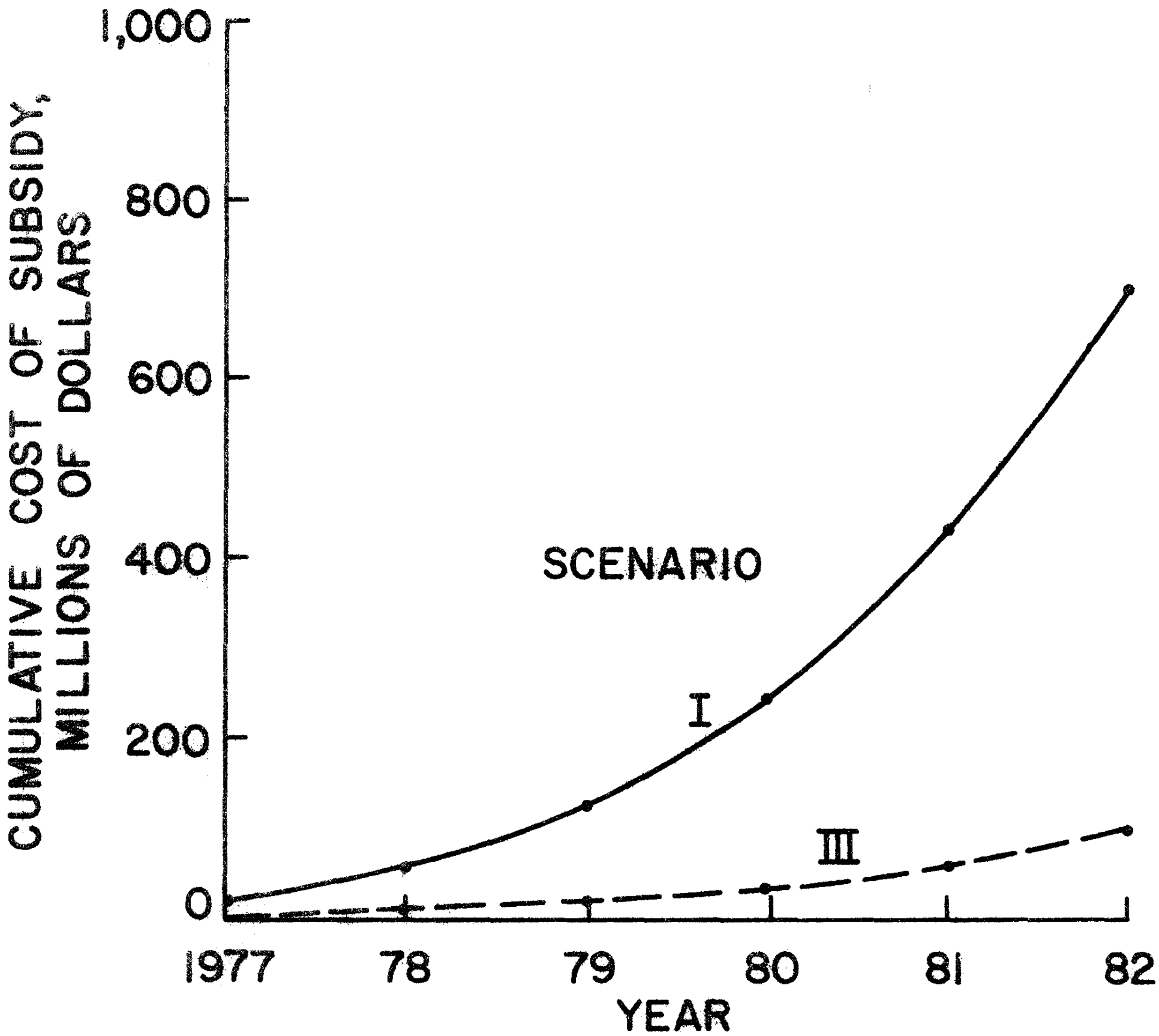


Figure 9. (continued). c. Cumulative Cost of Subsidy to Compete with Natural Gas

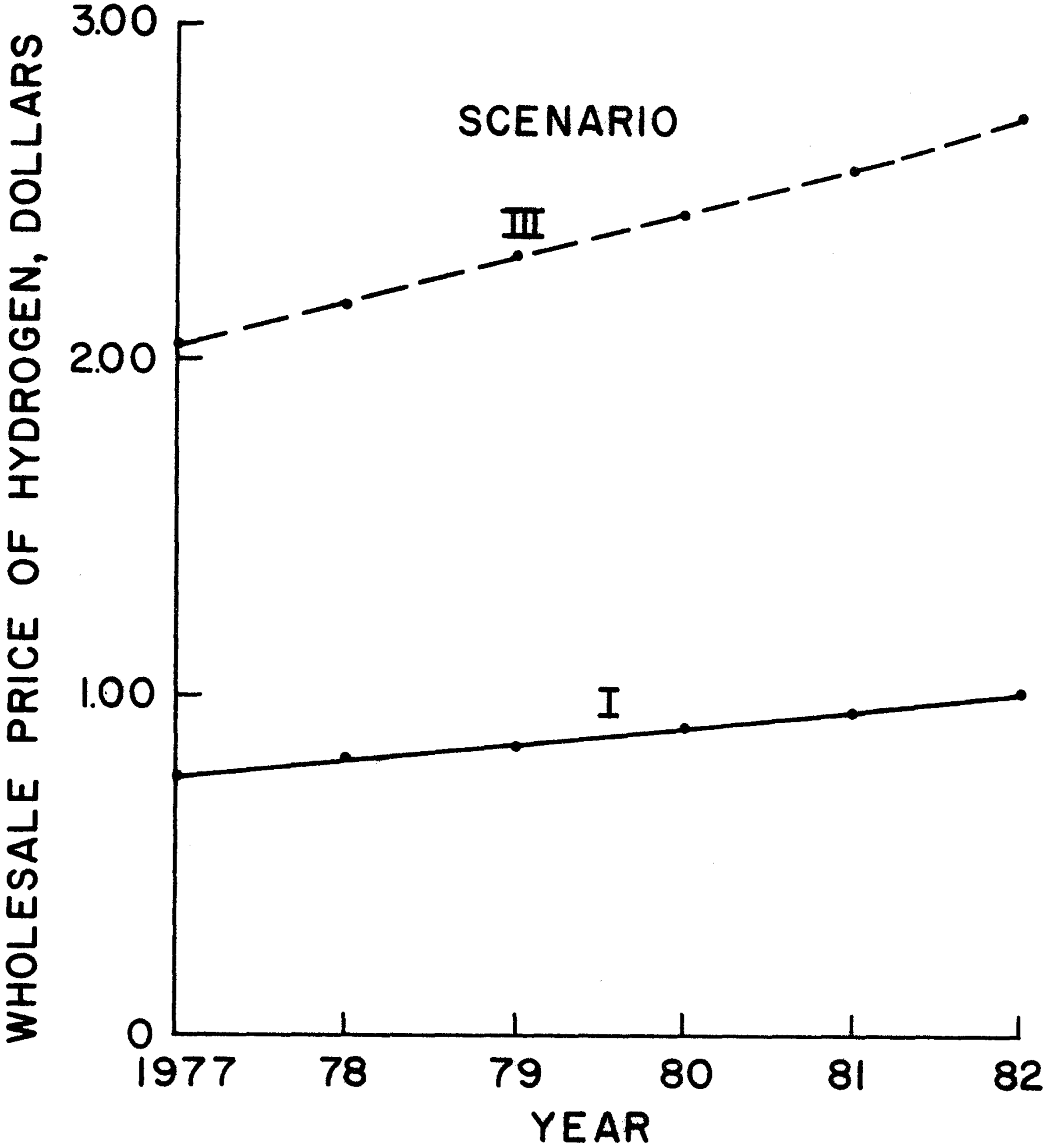


Figure 10. Forecast Hydrogen Conditions for Initial Cost of $\$1.00/10^6$ Btu with 10 percent/yr. Increase in Fuel Cost and 5 percent Decrease for 100 percent Increase in Production. Users Pay Average Price of 125 percent of Natural Gas Price, with 75 percent of Users Switching if Prices Equal a. Wholesale Price

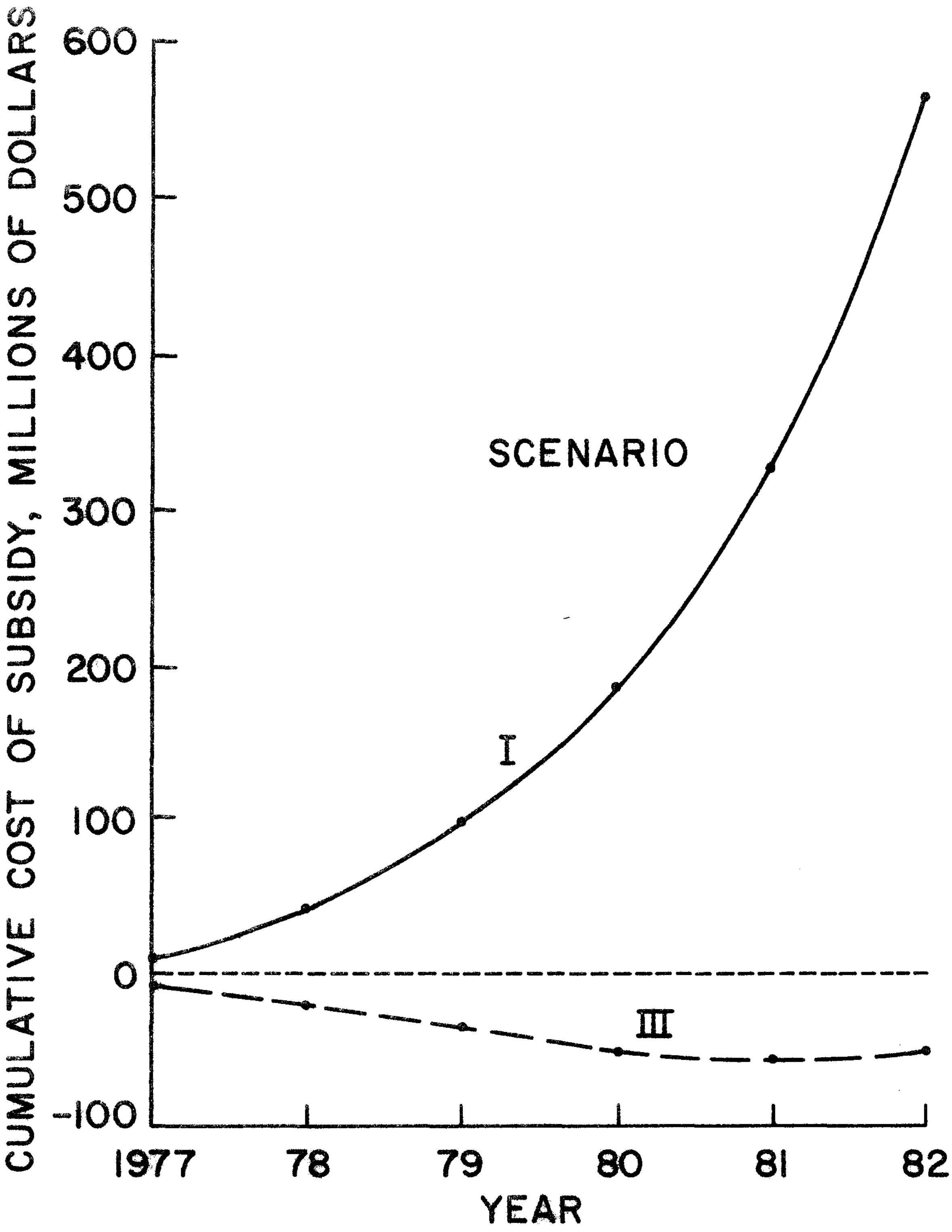


Figure 10. (continued). b. Cumulative Cost of Subsidy to Compete with Natural Gas

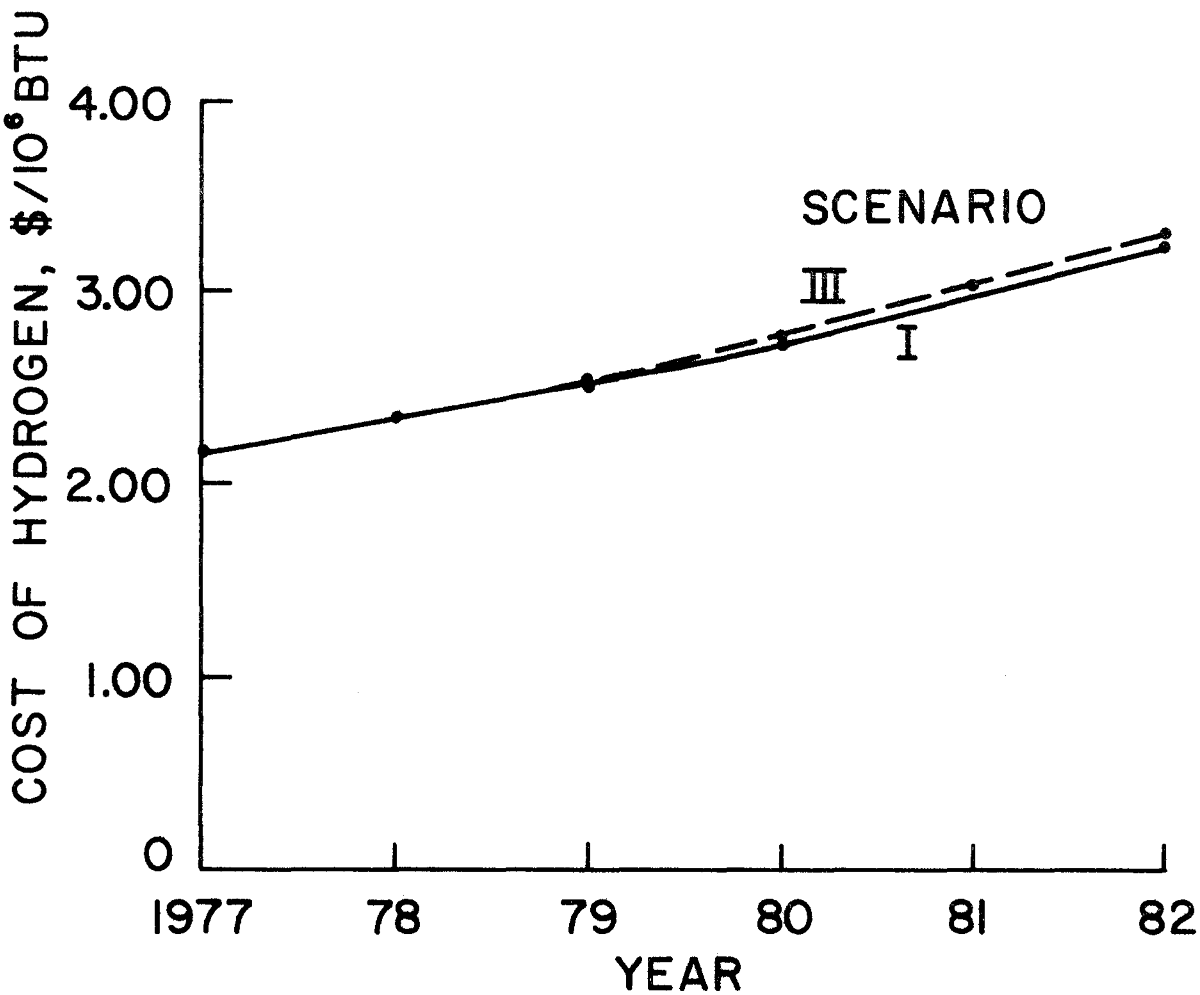


Figure 11. Forecast Hydrogen Conditions for Initial Cost of $1.75/10^6 Btu with 5 percent/yr. Increase in Fuel Costs and 5 percent Decrease for 100 percent Increase in Production. Users Pay Average Price Equivalent to Natural Gas Price, with 90 percent of Users Switching a. Cost of Hydrogen

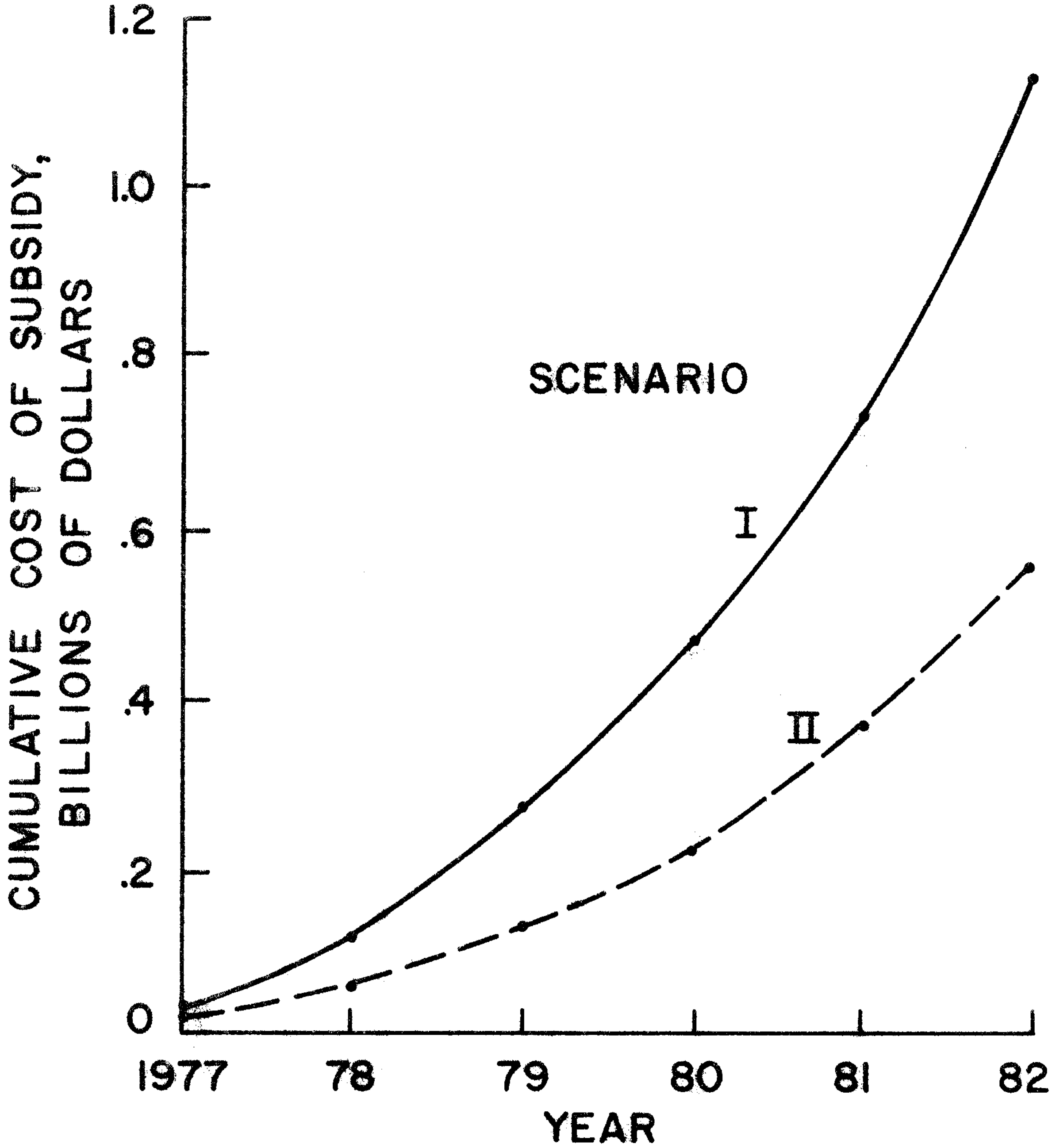


Figure 11. (continued). b. Cumulative Cost of Subsidy to Compete with Natural Gas

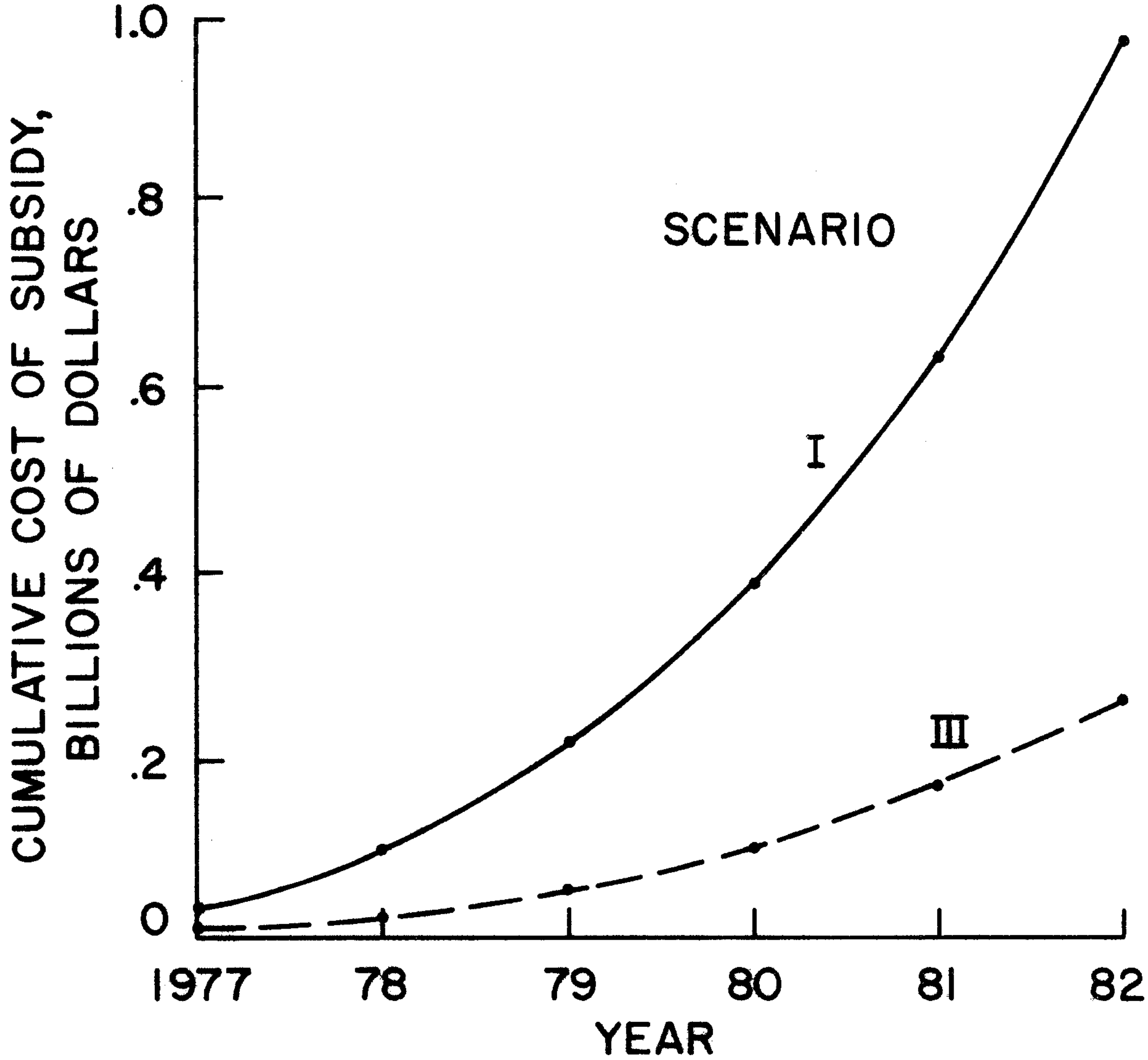


Figure 12. Forecast Cumulative Cost of Subsidy to Compete with Natural Gas. Initial Hydrogen Cost $1.75/10^6 Btu with 5 percent Decrease for 100 percent Increase in Production. Users Pay Average Price Equivalent to 125 percent of Natural Gas Price, and 75 percent of Users will Switch When Prices are Equal.

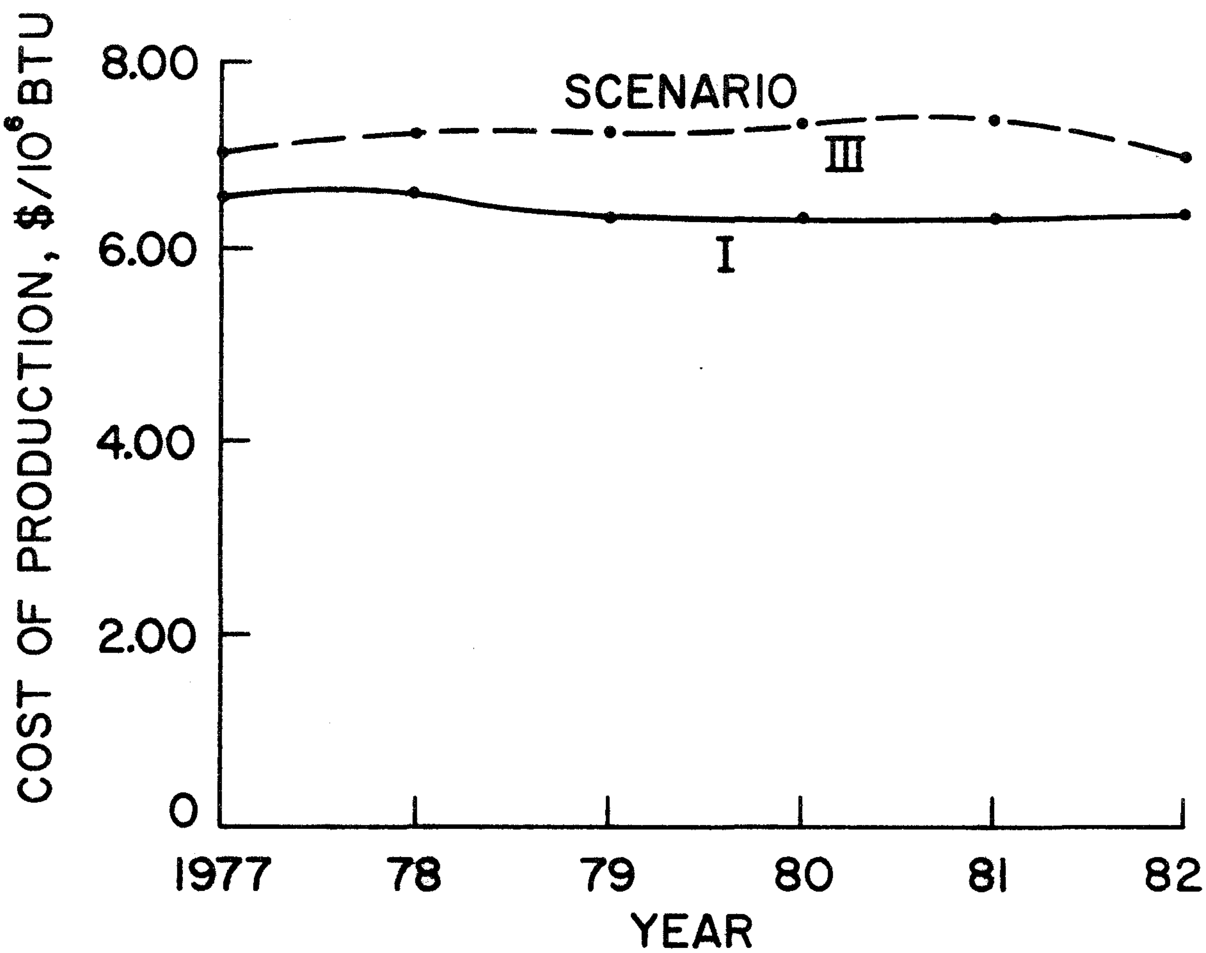


Figure 13. Forecast Hydrogen Conditions for Initial Cost of $\$3.75/10^6$ Btu with 15 percent Decrease for each 100 percent Increase in Production. Users Pay Average Price equal to that of Natural Gas, with 90 percent of users Switching if Prices are Equal. a. Cost of Production.

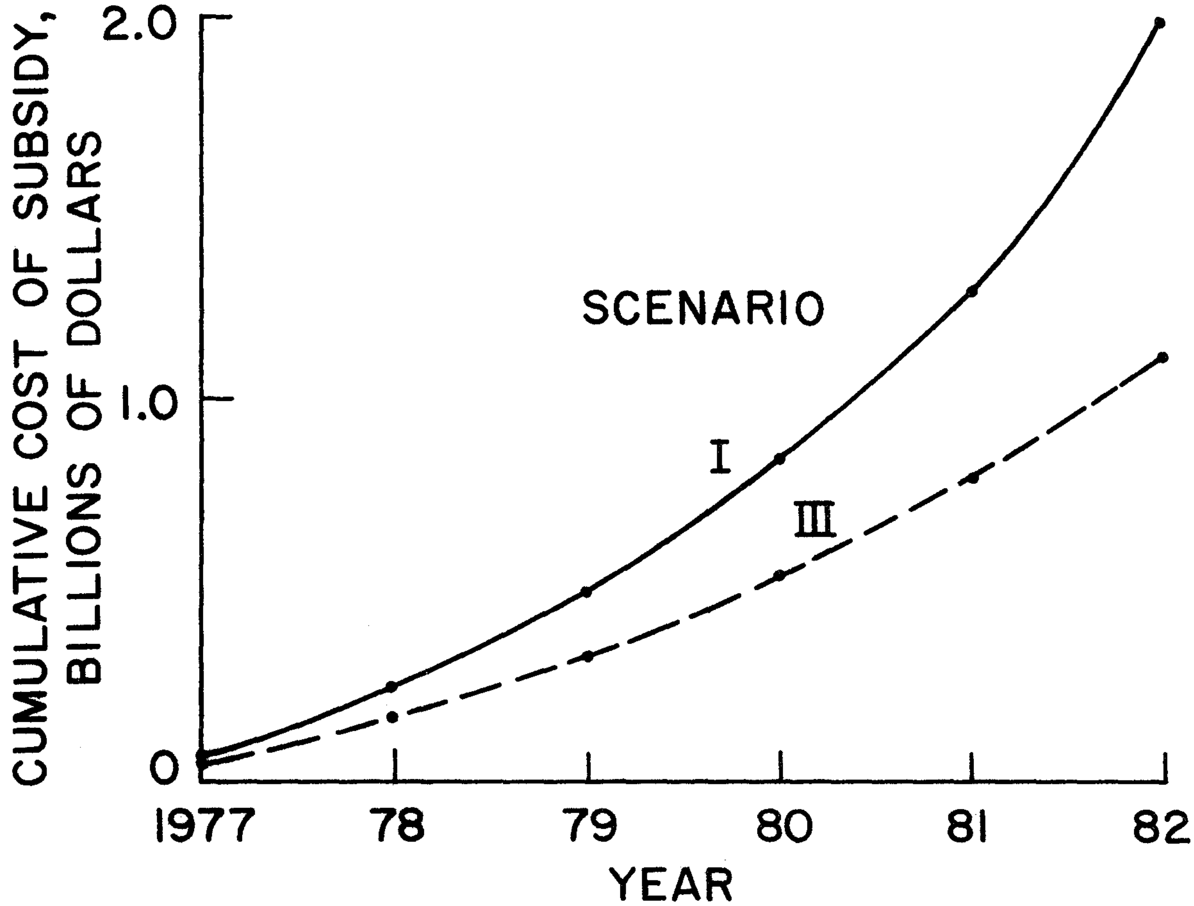


Figure 13. (continued). b. Cumulative Cost of Subsidy to Compete with Natural Gas.

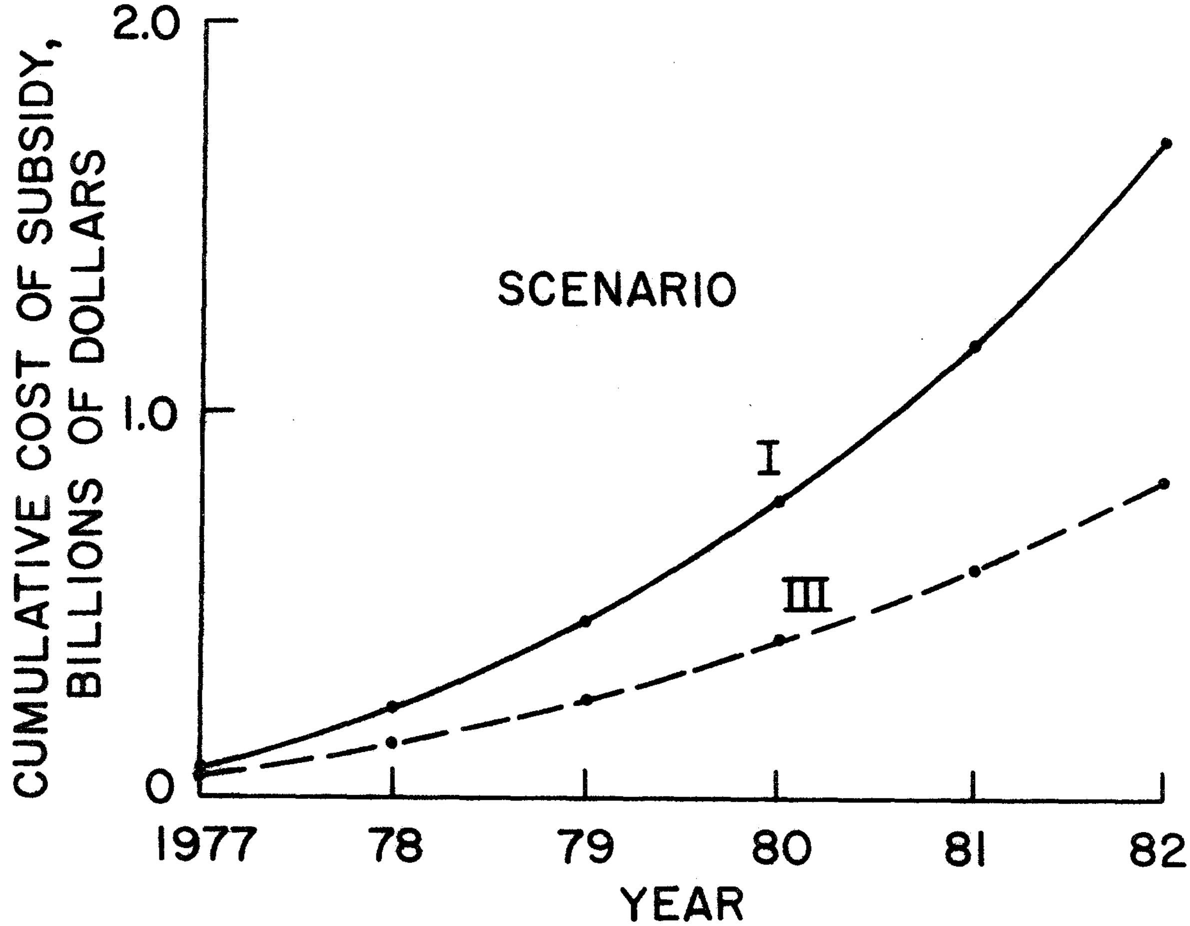


Figure 14. Forecast Cumulative Cost of Subsidy to compete with Natural Gas. Initial Hydrogen Cost $\$3.75/10^6$ Btu with 15 percent Decrease for Each 100 percent Increase in Production. Users Pay Average Price Equivalent to 125 percent of Natural Gas Price, and 75 percent of Users will Switch when Prices are Equal.

VI.D. Interpretation of Results

By careful examination of Figures 9-14 and/or the tabulated results in Appendix D, the following conclusions may be reached:

The cost to the State of Texas for implementing a hydrogen system competitive with the natural gas system in existence now would range from zero to over two billion dollars. These are total (cumulative) costs for a five-year subsidy program. The lower cost could result if hydrogen is produced at $1.00 per million Btu, (optimistic cost by coal gasification), natural gas prices are deregulated, and State policies are implemented that aid or require user acceptance. The higher cost could result if 1973 FPC policies are maintained for natural gas prices, and hydrogen is produced at $3.75 per million Btu (pessimistic cost by nuclear/electrolysis).

The most optimistic scenario predicts a net profit to the producer of some $50 million over a five year period. This assumes natural gas price deregulation and $1.00 per million Btu hydrogen costs plus customers willing to pay a premium for hydrogen over natural gas of 25%. This is not overly unrealistic, since the cost of amortizing pollution control equipment might well cover the increased cost of hydrogen.

All of these costs assume that hydrogen production begins in 1977, and by 1982 is supplying 5 percent of the total demand for gaseous fuels.

Finally, the natural gas supply/demand model predicts that natural gas supplies will become inadequate within a period of less than twenty years, regardless of the conditions put on the model. An alternative seems necessary, and the State is in a position to begin providing the basis for such an alternative by beginning a demonstration hydrogen system now.

APPENDIX A

Econometric Model

Appendix A

Econometric Model

A computerized econometric model is available on the UNIVAC 1108 of the University of Houston. A computerized energy data base is simultaneously available on the same computer to provide historical data necessary to regressions of the different variables.

The model can be used to simulate the economics of natural gas and hydrogen and to forecast conditions for the 10 year period to come. Two classes of problems are studied in the model:

First, what are the different policies feasible for the State? How can the state of Texas efficiently accelerate the phasing of hydrogen into Texas' economy?

Second, what will be the production price of hydrogen that would result, in comparison of that of other energy sources, and in particular, natural gas? How can hydrogen contribute to reducing the predicted shortage of natural gas? What will be the new distribution of energy sources in the different sectors of Texas' economy?

Preliminary Assumptions

To answer these questions, we have been led to make the following assumptions:

1. Hydrogen has been considered to be directly competitive with natural gas. Whenever it was possible, a single market, "gaseous fuels", was considered and hydrogen and natural gas were supposed to be competitors inside the market.

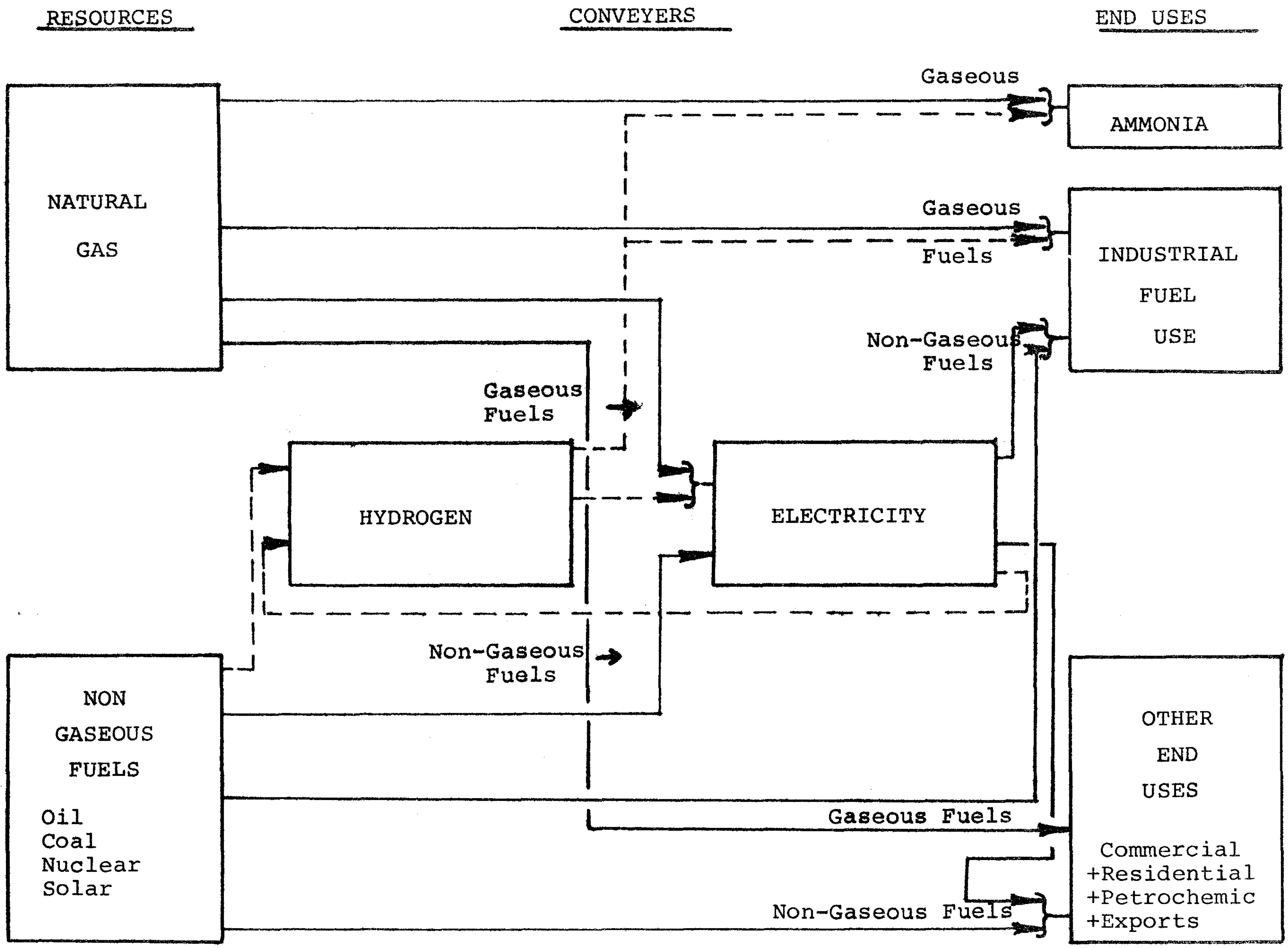


Figure A-1. Possible Substitutions of Hydrogen into the Texas Energy System

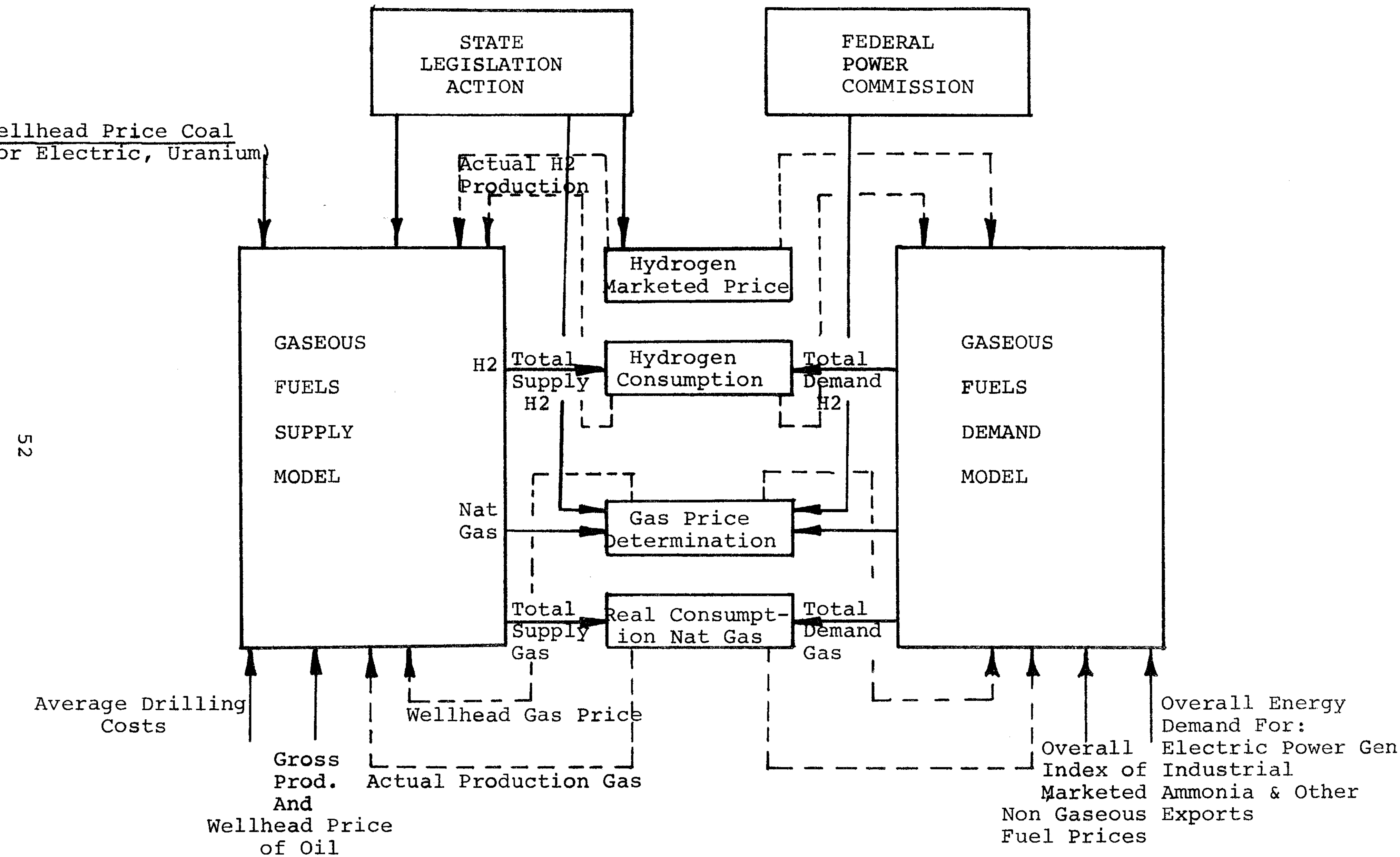


Figure A-2. Outline of Supply/Demand Model

2. A "maximum" development curve for hydrogen supply was considered, i.e., the time delays for installation and investment relative to hydrogen production were supposed minimal.

3. Different assumptions have been considered for the attitude of the Federal Power Commission towards the prices of natural gas ranging from "complete deregulation of the field prices of natural gas" to "maintenance of the regulatory status-quo."

4. Predictions concerning prices of coal, oil and nuclear energy are an average of state predictions. Other exogenous variables, including inflation indexes and overall energy demand for each relevant sector of the Texas economy are predicted to grow in proportion to national "pessimistic" or "conservation" curves.

5. Predictions concerning Texas exports of natural gas have been regressed against prices of natural gas, and are assumed to follow the recent trends.

Boundaries of the Model

Figure A-1 shows the transition to hydrogen. The only resource where supply is actually endogenous to the model is natural gas. The "relevant" end uses for hydrogen appear to be

a. ammonia and petrochemical production
b. electric power generation
c. industrial fuel use

No impact in the following 20 years is expected on the residential and commercial sectors. No interstate exchange seems possible during this time period.

The possible sources of hydrogen appear to be

coal or electricity

Various proportions of these two sources are considered. Costs and fuel use of fabricating hydrogen relative to these proportions were computed from coal and electric power price estimation.

Overall Presentation of the Model

Figure A-2 shows a general presentation of the model, which is a supply and demand model for gaseous fuels in Texas. Without federal (FPC) and Texas controls, the wholesale and wellhead prices of hydrogen and natural gas are endogenous variables. But the external control of maximum prices by the FPC over both the wellhead price of natural gas and the benefit taken by pipeline owners creates a situation in which the supply no longer equals the demand of natural gas, and a shortage is created. Both these prices feed-back in changes in demand, and in changes in drilling activity and reserve detention by the gas drillers.

a) Supply Model

The supply model was actually broken down into a supply of natural gas and of hydrogen.

1. Supply of hydrogen. The supply of hydrogen is fully determined by the wholesale (exogenous) price of hydrogen, and the marginal costs of producing hydrogen out of coal and electricity. Important time-lags were introduced to take into account the lack of infrastructure for hydrogen production.

2. Supply of natural gas. The model is an adaptation to Texas economy of the MIT model for natural gas from Paul McAvoy and Robert S. Pindyck. All coefficients are specifically regressed for Texas by district of the Federal Power Commission on historical data from 1966 to the present. It shows the impact of the externally controlled top gas prices at wellhead upon the production out of reserves and the drilling activity. The main exogenous variables (for which average extrapolations were taken) are:

    a. gross production and wellhead price of oil
    b. deflation index
    c. average total drilling costs

b) Demand Model

The demand model is a generalization for gaseous fuels of both the MIT model and Balentra's "The Demand for Natural Gas in the United States." All estimations are made by market, specifically:

a. ammonia and petrochemical markets
b. electric power generation markets
c. industrial fuel use market
d. other commercial and residential markets
e. exports

Regressions are made on historical data from 1966 to 1973. For accuracy purposes, data concerning New Mexico and Louisiana South will be considered.

The exogenous variables include:

a. overall energy consumption for fields b,c,d.
b. overall gas consumption for ammonia
c. gas exports
d. losses, pipeline fuels
e. inflation index
f. non-gaseous fuels price index (marketed prices)

An Example: Industrial Fuel Use

Exogenous Variables:

OED	overall energy demand for industrial fuel use
NGFPR	non-gaseous fuels price index
r, r'	replacement rates for gaseous fuel equipment and non-gaseous fuel equipment
T	average life of hydrogen equipment

(1) $ND_t = OED_t - OED_{t-1} + r{*}GFD_{t-1} + r'{*}NGFD_{t-1}$

(1) determines ND_t, "new" overall energy demand for industrial fuel use. This demand is actually the sum of two terms

$OED_t - OED_{t-1}$ is the increase in overall energy demand

$r{*}GFD_{t-1} + r'{*}NGFD_{t-1}$ is the replacement factor for continuation of old consumption

r and r' are the replacement rates of old equipment of gaseous fuel burners and non-gaseous fuel burners, respectively. GFD_{t-1} and $NGFD_{t-1}$ are gaseous fuels, and non-gaseous fuel demand for industrial use. They are related by

(2) $OED_{t-1} = GFD_{t-1} + NGF_{t-1}$

This "new" demand for energy is then broken down into demand for gaseous fuel and non-gaseous fuel.

(3) $ND_t = ND_t^1 + ND_t^2$

The "new" gaseous fuel demand is then regressed against comparative prices of gaseous and non-gaseous fuels.

(4) $\dfrac{ND_t^1}{ND_t} = f^1(gfr_{t-1}, ngfr_{t-1})$

The "total" demand of gaseous fuels for the year t is then obtained by

$$(5) \quad GFD_t = GFD_{t-1}(1-r) + ND_t^1$$

Similarly, the separated "new" demands for hydrogen and natural gas constitute the "new" demand for gaseous fuels:

$$(6) \quad ND_t^1 = ND_t^{11} + ND_t^{12}$$

and the proportion of "new" hydrogen demand over "new" gaseous fuel demand is regressed against price of hydrogen and price of natural gas:

$$(7) \quad \frac{ND_t^{11}}{ND_t^1} = f^2 \; (hr_{t-1}, gr_{t-1})$$

The "total" demand for hydrogen is then

$$(8) \quad HD_t = HD_{t-1} - HD_{t-T-1} + ND_t^{11}$$

where $HD_{t-1} - HD_{t-12}$ represents the demand for hydrogen for year t-1 minus a replacement factor (the average life of hydrogen equipment being T).

The prices considered are the wholesale prices. The non-gaseous fuel prices are actually exogenous, as shown in

$$(9) \quad ngfr_t = NGFPR_t$$

The gaseous fuel price index is computed from prices of hydrogen and natural gas by

$$(10) \quad gfr_t = (hr_t{*}HD_t + gr_t{*}(Gfd_t - HD_t))/GFD_t$$

(weighted average of hydrogen and natural gas fuel prices).

The Hydrogen Mini-Model

A hydrogen mini-model was designed and connected to the natural gas model, to make possible the study of alternate price policies on natural gas upon the hydrogen scenarios. Some provision was also made to measure the reciprocal impact of the hydrogen case upon natural gas, but the measured impact was found to be negligible, and thus the idea was dropped.

The economical controversies about the costs and demand sensitivities caused us to make the hydrogen model interactive as well. Most variables may be changed dynamically by the programmer; in particular, as will be shown, a cost curve and a demand curve were directly inputted by the operator, enabling him to test very different alternatives. A list of the operator-controlled variables is to be found at the end of Appendix A.

Time-Lags and Production Level

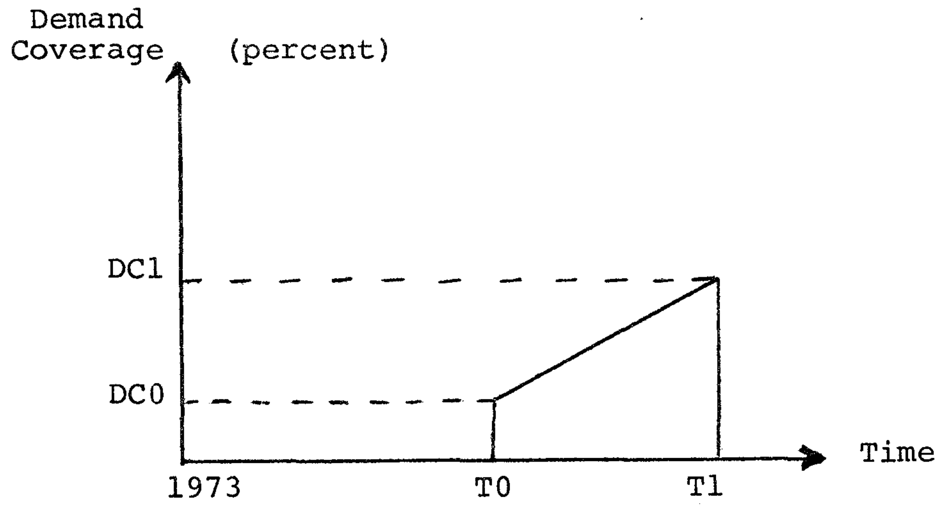
Production is a matter of

-policy, since a subsidy is anyway required

-technological time-lags for initial start and further development

Demand Coverage

A particular demand sector was considered (more specifically, we took the electric power generation sector), and demand coverage in this sector was supposed to be a linear function of time.



Demand sector, T0, T1, DC0, DC1 are input to the program

Cost Curves

The marginal production cost curve is of the form

$$C_t = a + b * C_{t-1} + c * P_t$$

cost of an add'l
Btu for year t

To be inputted:

-an initial cost per Btu in 1972 dollars

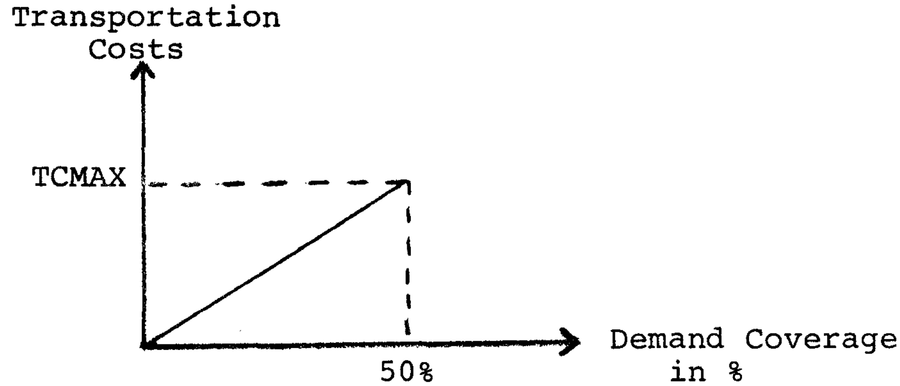
-a percent increase in marginal cost per year (allowing for increase in cost of input fuel)

-a percent decrease in marginal cost per additional 100% increase in production.

This enables the program to compute a,b,c

A transportation cost is then computed by the program. The marginal transportation cost of hydrogen with respect to demand coverage is of the form

$$TC\ (DC) = TCMAX * \frac{DC}{100}$$



This assumes that

- no transportation occurs for the initial Btu produced (distributed to close-by industries)
- the number of miles transported is linear function of demand coverage, further and further industries being equipped

To be inputted are an index of hydrogen transportation costs per mile and Btu, with natural gas value taken for basis, enabling the program to compute TCMAX.

Demand Sensitivity

The demand for natural gas is now considered to be a demand for gaseous fuels.

Each year, the "new" demand, a portion of the demand susceptible to switch to hydrogen, is by definition:

$$NDGF_t = GFD_t - GFD_{t-1} + \frac{1}{R} * GFD_{t-1}$$

Where: GFD_t is the demand for gaseous fuel from the sector considered on year t

$GFD_t - GFD_{t-1}$ the incremental change in demand for year t

R the average life of gas-burning equipment ($R \approx 7$)

$\frac{1}{R} * GFD_{t-1}$ the demand resulting from replacement of old equipment.

The portion of this new demand switching to hydrogen is then estimated by:

$$NDH2R_{(t)} = a + b * H2PRR$$

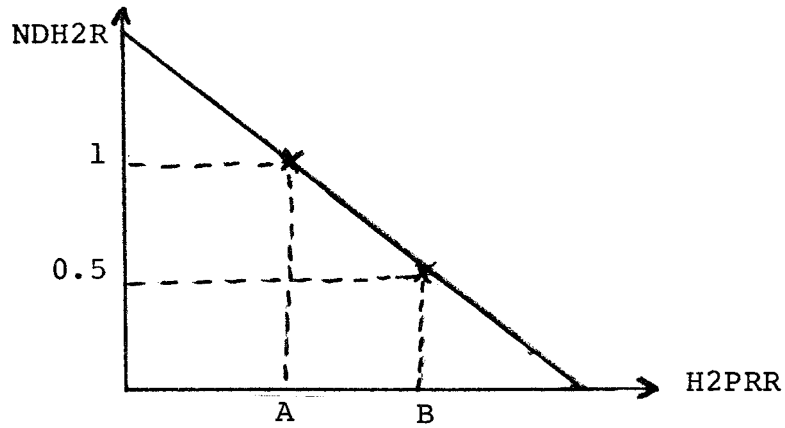
where H2PRR is the artificial price ratio hydrogen/natural gas (the higher hydrogen prices, the lower the demand).

Two points must be estimated on this curve, and have to be inputted to the program:

-proportion of users willing to switch if prices are equal (A)

-average price users are ready to pay for Hydrogen (B)

The curve is then determined



The demand for hydrogen in year t is then

$$H2D_t = H2D_{t-1} + NDH2R_t * NGFD_t$$

$H2D_t$: demand for hydrogen at year t

NGFD, NDH2R as above.

An optimum price ratio may then be computed which corresponds to the level of demand coverage seeked.

Optimum Wholesale Price Determination

The next step is to compute the optimum price for hydrogen knowing the value for H2PRR for year t.

An attempt was made to take into account the big differences occurring between geographical locations for the price of gas. The operator may input a local index of the wholesale price of gas, (LPG), for the given sector with 100 = average price over Texas. We define a marginal price of gas with respect to demand coverage as:

$$MPGAS(DC) = WPGASS*(LPG + \frac{DC}{50} * (100-LPG))$$

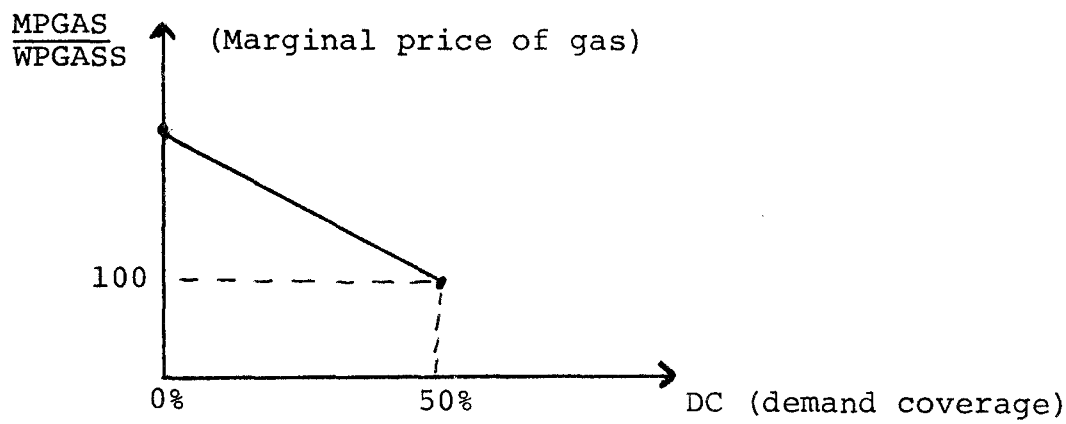
Where: MPGAS is the marginal price of gas with respect to demand coverage,

WPGASS is the average price of gas in Texas in the specified sector,

DC is the demand coverage,

LPG is local price of gas index.

This yields a curve of the form



The "optimum" hydrogen prices for new contracts is then:

$$H2PR = MPGAS * H2PRR$$

Finally, the total state expense results from the total difference between cost of producing and transporting hydrogen with benefits from large scale demand, and the price that is paid.

THE MODEL COMPUTATIONS

A-1 Main Equations

A-1-1 Supply

1. Drilling activity is first estimated by:

   WXT (I,J) = A1*REVDD(I,J-1) + A2* ATCD(I,J-1)+ CTT

   WXT (I,J) : number of wells drilled (total, successful or not) for year J and zone I.

   REVDD (I,J) : deflated revenue from both gas and oil for plants in zone I and year J. (computed from exogenous)

   ATCDD (I,J) : index of average total drilling costs. (exogenous).

2. Discovery size is then estimated:

   SIZEDT (I,J) = A1* (PG(I,J-1)+PG(I,J-2)+PG(I,J-3))/3
   +A2* (PO(I,J-1)+PO(I,J-2)+PO(I,J-3))/3
   +A3* (ATCDD(I,J-1)+ATCDD(I,J-2)+ATCDD(I,J-3))/3
   +A4* CNXT(I,J-1)+CTT

   SIZEDT(I,J) : average size of a discovery per well, average over all wells, successful or not.

   (PG(I,J-1)+PG(I,J-2)+PG(I,J-3))/3 : average over three years of the wellhead price of gas.

   (PO(I,J-1)+PO(I,J-2)+PO(I,J-3))/3 : average over three years of the wellhead price of oil.

   (ATCDD(I,J-1)+ATCDD(I,J-2)+ATCDD(I,J-3))/3 : average over three years of the total drilling costs.

   CWXT(I,J-1) : cumulative number of wells drilled since 1966 in zone I and up to year J-1.

3. Discoveries are then given by the identity:

DT(I,J) = SIZED(I,J)*WXT(I,J)

DT(I,J) : total discoveries of natural gas for year J and zone I

4. Extensions of previous discoveries are estimated by:

XT(I,J) = A1*WXT(I,J-1)+A2*DT(I,J-1)+CTT

XT(I,J) : total extensions of previous discoveries for year J and zone I

5. Revisions of previous estimations are estimated by:

RT(I,J) = A1*(YT(I,J-1)-YT(I,J-2))+CTT

where RT(I,J) : total revisions of previous estimations concerning discoveries for zone I and year J

YT(I,J-1)-YT(I,J-2) : change in year-end reserves of natural gas occurring in zone I during the year J-1

6. - 7. - 8. Year end reserves and production are estimated then by the system

$$\begin{cases} YT(I,J) = YT(I,J-1)+DT(I,J)+XT(I,J)+RT(I,J)-P(I,J)-DUS(I,J) \\ P(I,J) = A1*YT(I,J)+A2*LOG(PG\ (I,J))+CTT \\ DUS(I,J) = A1*P(I,J)+CTT \end{cases}$$

where:

YT(I,J) : reserves of natural gas for zone I at the end of year J

XT(I,J-1) : reserves of natural gas for zone I at the end of year J-1

DT(I,J) : total discoveries of natural gas for zone I, year J

XT(I,J) : total extensions of natural gas for zone I, year J

RT(I,J) : total revisions of natural gas for zone I, year J

P(I,J) : total net production (as defined by Bureau of mines) coming from zone I during year J

DUS(I,J) : change in underground storage (other than in original locations) during year J in zone I

A-1-2 Intermediate

9. Marketed production for Texas is:

MP(J) = A1*P(1,J)+CTT

where MP(J) : marketed production in Texas (production minus exports plus imports)

P(1,J) : Total Texas production (net) of natural gas during year J.

10. Supply of natural gas in Texas is estimated by

TC(J) = A1*MP(J)+CTT

where TC(J) : Total supply in Texas (marketed production - vented and flared - pipeline fuel).

11. Field consumption is then estimated

CFIELD (J) = AL*P(1,J)+CTT

CFIELD(J) : Field consumption in Texas.

12. Finally, the maximum satisable demand is given by the identity:

MPROPD(J) = TC(J) - CFIELD(J)

MPROPD(J) : Maximum demand satisfiable in Texas on the end market for year J.

A-1-3 Demand

13. Wholesale prices are estimated per sector

WPGAS (I,J) = A1 (PG(1,J-1)+PG(1,J-2)+PG(1,J-3))/3.0+CTT

WPGAS (I,J) : PRICE of gas on the wholesale market corresponding to sector I, during year J

(PG(1,J-1)+PG(1,J-2)+PG(1,J-3))/3.0: Average wellhead price of gas over Texas and over three past years (PG exogenous)

14. "New" demand overall is by definition

$$\text{NOED}(I,J) = \text{OED}(I,J) - \text{OED}(I,J-1) + \frac{1}{R(I)}\,\text{GFD}(I,J-1) + \frac{1}{RR(I)}\,(\text{OED}(I,J-1) - \text{GFD}(I,J-1))$$

NOED (I,J) : "new" overall energy demand for sector I and year J

OED(I,J) : overall energy demand for sector I and year J (exogenous)

OED(I,J)-OED(I,J-1) : incremental change in demand for year J and sector I

R(I) : Average time-life of gas-burning appliances for sector I (exogenous)

RR(I) : Average time-life of non gaseous-fuel burning appliances for sector I (exogenous)

GFD(I,J-1) : natural gas demand for sector I and year J-1

$\frac{1}{R(I)}$ GFD(I,J-1) : demand resulting from replacement of old gas-burning appliances

$\frac{1}{RR(I)}$ (OED(I,J-1)-GFD(I,J-1)) : Demand resulting from replacement of old non-gaseous fuel-burning appliances

15. Price ratio is then computed:

$$WPR(I,J) = \frac{WPGAS(I,J)}{WPNGF(I,J)} * \frac{WPNGF(I,1968)}{WPGAS(I,1968)} * 100$$

WPR(I,J) : index of ratio wholesale prices - non gaseous fuels with 1968 = 100, sector I

WPNGF(I,J) : wholesale average price of non gaseous fuels for sector I and year J (exogenous)

WPGAS(I,J) from 13

16. The proportion of new demand going to natural gas is then regressed:

NGFDR(I,J) = A1*WPR(I,J)+CTT

NGFDR(I,J) : Proportion of "new" energy demand going to natural gas

WPR(I,J) from 15

17. Hence, "new" natural gas demand is:

NGFD(I,J) = NGFDR(I,J)*NOED(I,J)

NGFD(I,J) = "new" natural gas demand for sector I and year J

18. Natural gas demand can then be computed:

$$GFD(I,J) = GFD(I,J-1)+NGFD(I,J) - GFD(I,J-1)*\frac{1}{R(I)}$$

GFD(I,J) : Natural gas demand for sector I and year J

NGFD(I,J) : "new" natural gas demand, from 17

$GFD(I,J-1)*\frac{1}{R(I)}$: Demand resulting of replacement of old gas burning appliances.

19. Finally, the shortage in Texas is:

$$SHORT\ (J) = \sum_{I=1}^{3} GFD(I,J) - MPROPD(J)$$

SHORT(J) : Total Texas shortage for year J

$\sum_{I=1}^{3}$ GFD(I,J) : Total over all sectors of natural gas demand for year J, from 18

MPROPD(J): Maximum demand satisfiable in Texas for year J as computed by 12

A-2 <u>List of demand sectors</u>

I = 1 : Residential - commercial sector

I = 2 : Industrial fuel use

I = 3 : Electric Power Generation

I = 4 : All sectors

A-3 <u>List of supply zones</u>

I = 1 : Whole state (Texas)

I = 2 : TRRC district #1 (Texas Railroad Commission)

I = 3 : TRRC district #2

I = 4 : TRRC district #3

I = 5 : TRRC district #4

I = 6 : TRRC district #5

I = 7 : TRRC district #6

I = 8 : TRRC district #7B

I = 9 : TRRC district #7C

I = 10: TRRC district #8

I = 11: TRRC district #8A

I = 12: TRRC district #9

I = 13: TRRC district #10

A-4 Boundaries for regression

Equations relative to supply regressed by supply zone (I=2 to 13), then aggregated for Texas.

Intermediate equations and demand equations regressed for Texas, Louisiana, New Mexico to provide enough points for regression.

Time boundaries for regression : 1968-1972

A-5 The exogenous variables

For supply

1 PO : Production of oil at wellhead

2 PROIL : Price of oil at wellhead

3 ATCD : Average drilling costs per well (index)

For demand

4 OED(I) : Overall energy demands per sector

8 WPNGF(I) : Wholesale price index for non gaseous fuel per sector

12 R(I) : Average time - life of gas-burning appliances per sector

16 RR(I) : Average time - like of non gaseous fuel-burning appliances per sector

For both

17 INDEX: Index price of consumer prices (inflation index)

18 PG : Wellhead price of gas, average Texas, as controlled by Federal Power Commission regulations.

( ) H2D(J) = MGFD(S,J)

(H2PD(H2T1-J)

1 + H2P1*(J-H2T0)

/100/(H2T1-H2T0)

H2T0 Initial year for H2 production (exog)

H2T1 Final year for H2 production (exog)

S Sector envisioned (exog)

H2P0 Initial demand coverage of sector S in %(exog)

H2P1 Final demand coverage of sector S in % (exog)

MGFD(S,J) Demand for gaseous fuels for year J and Sector S

H2D(J) Demand for hydrogen for year J

( ) H2DD(J) = H2D(J)-H2D(J-1)

H2D from (1)

H2DD(J) "New" (additional) demand for year J

( ) H2PG(J) = MWPGAS (S,J)

(H2PG0/100 + H2D(J)/MGFD(S,J)(1.0-H2PG0/100)

MWPGAS(S,J) Average over Texas of price of gas at wholesale for year J over sector S

H2PGO Index of price of gas at plant if Texas = 100 (exog)

H2PG(J) "Marginal" competitive gas price

( ) H2NGFD(SECT,J) = MGFD - MGFD(S,J-1) + $\frac{1}{R}$ MGFD(S,J-1)

H2NGFD(SECT,J) = "New" demand for gaseous fuels occurring during year J on sector S

MGFD(S,J)-MGFD(S,J-1) Incremental charge in demand for gaseous fuels

R Average lifetime of gas-burning equipment

MGFD(S,J-1)/R Demand resulting of replacement of old equipment

( ) H2PR(J) = H2PG(J)*(H2DD(J)/H2NGFD(S,J) - 0.5 + H2MAX/100*(H2AVR/100 -H2DD (J)/H2NGFD(S,J))

H2PR(J) "Marginal" wholesale hydrogen price

H2DD(J) from (2)

H2NGFD(SECT,J) "New" demand for gaseous fuels (incremental demand + renewal of old equipment) for sector S and year J

H2MAX Average price users are ready to pay for hydrogen given that they are "new users" and gas prices = 100 (exogenous)

H2AVR Average percent of "new" users that would switch to H2 if prices of hydrogen were equal to gas prices (exogenous)

( ) H2P(J) = H2D(J)*(1.0 + H2PRO/100)

H2P(J) Production of hydrogen for year J

H2D(J) Demand for H2 for year J

H2PRO Percentage losses (exogenous)

( ) H2PC(J) = H2PC(J-1)*INDEX(J)/INDEX(J-1)*(1.0 + H2A2/100.0 + H2A3/100.0*
(H2P(J)-H2P(J))/H2P(J))

H2PC(J) "Marginal" production cost (inflated)

Index(J) Inflation index (1968 = 100)

H2A2 Percentage increase per year in cost of input fuel (deflated)(exogenous)

H2A3 Expected percentage decrease per year in production cost for additional 100% increase in production (deflated, exogenous)

( ) H2TC(J) = H2TCO/100*(MWPGAS(S,J)-PG(1,J))
*H2D(J)/(MGFD(S,J)-H2D(J))

H2TC(J) "Marginal" transportation costs for hydrogen

H2TCO Index of hydrogen transportation costs/Btu and per mile, natural gas = 100 (exogenous)

MWPGAS(S,J) Average wholesale gas price in Texas for sector S and year J

PG(1,J) Average wellhead gas prices in Texas year J

( ) H2COST(J) = H2PC(J) + H2TC(J)

H2COST(J) "Marginal" cost of hydrogen

( ) Expense is then computed by integrating (H2PR(J)-H2COST(J))d(H2D) dt over the time period (relatively to dt) and over the demand (relatively to D(H2D))

List of Endogenous Variables

t	current year	
gfr_t	gaseous fuels price index	Average Wholesale Prices
$ngfr_t$	nongaseous fuels price index	Average Wholesale Prices
gr_t	natural gas price index	Average Wholesale Prices
hr_t	hydrogen price index	Average Wholesale Prices
ND_t	new overall energy demand	For Industrial Fuel Use
ND_t^1	new gaseous fuel demand	For Industrial Fuel Use
ND_t^2	new non-gaseous fuel demand	For Industrial Fuel Use
ND_t^{11}	new hydrogen demand	For Industrial Fuel Use
ND_t^{12}	new natural gas demand	For Industrial Fuel Use
GFD_t	total gaseous fuel demand	For Industrial Fuel Use
$NGFD_t$	total non-gaseous fuel demand	For Industrial Fuel Use
HD_t	total hydrogen demand	For Industrial Fuel Use
GD_t	total natural gas demand	For Industrial Fuel Use

APPENDIX B

Contributors

To assess the future of hydrogen in Texas' energy markets, the following University of Houston personnel were enlisted, in addition to the principal investigators:

Dr. William B. Lee: Determination of alternative means of producing and distributing hydrogen and the costs relative to competing systems over the next ten-year period. Use of "learning curve" and breakeven analysis.

Dr. Bayliss C. McInnis and Mr. Jean-Luc Konrat: Set up energy data base for Texas using input from Governor's Office of Information Services. Further, MIT model of natural gas industry is being applied to Texas for pricing of natural gas in the future and the relative cost of hydrogen.

Dr. Gordon Otto: Consulting on the information presently available or being developed within the University on energy usage in other forms.

Dr. Howard Plotkin: Forecast of hydrogen costs and means of phasing a hydrogen system into the existing energy economy of the State.

APPENDIX C

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APPENDIX D

Tabulated Data

TABLE D-I

DATA FOR NATURAL GAS SCENARIOS

Scenario	Year	Discoveries 10^{15} Btu	Production 10^{15} Btu	Reserves 10^{15} Btu	Shortage 10^{15} Btu	Wellhead $\$/10^6$ Btu	Wholesale $\$/10^6$ Btu
I	1973	1.3	7.8	89.8	0.6	.173	.350
	1975	1.1	7.7	76.5	1.2	.193	.392
	1977	0.9	7.5	63.3	1.8	.214	.437
	1979	0.7	7.4	50.2	2.6	.239	.477
	1981	0.4	7.2	37.2	3.5	.266	.541
II	1973	1.3	8.1	89.5	0.5	.189	.385
	1975	1.4	8.5	74.9	0.6	.249	.520
	1977	1.7	9.0	60.6	0.8	.330	.695
	1979	2.3	9.6	47.4	1.0	.436	.925
	1981	3.3	10.0	36.6	1.2	.577	1.226
III	1973	1.3	10.0	87.5	-0.7	.328	.701
	1975	4.1	10.8	71.8	-1.0	.487	1.059
	1977	5.5	11.0	66.0	-0.9	.567	1.190
	1979	5.8	11.3	63.6	-0.9	.614	1.336
	1981	6.2	11.7	62.6	-0.8	.690	1.696

TABLE D-II

DATA FOR HYDROGEN FORECASTS

Case	Nominal Cost of Hydrogen Dollars	Year	Production 10^{15} Btu	Cost Dollars	Price Dollars	Cumulative Expense 10 Dollars	Natural Gas Scenario	Avg. Price Ready to Pay Percentage Natural Gas	Percent Switch at Equal Price
1	$1.00 +	1977	0.03	$1.27	$0.47	18	I	100	90
	10%/Yr.	78	.05	1.40	0.50	59	↓	↓	↓
		79	.09	1.59	.52	133	↓	↓	↓
		80	.12	1.81	.55	252	↓	↓	↓
		81	.17	2.05	.58	435	↓	↓	↓
		82	.13	2.33	.62	706	↓	↓	↓
2	$1.00 +	1977	0.02	1.25	1.23	4	III	100	90
	10%/Yr.	78	.04	1.42	1.30	11	↓	↓	↓
		79	.07	1.62	1.38	22	↓	↓	↓
		80	.09	1.86	1.46	39	↓	↓	↓
		81	.12	2.10	1.54	66	↓	↓	↓
		82	.16	2.40	1.64	99	↓	↓	↓
3.	$1.00 +	1977			0.79	13	I	125	75
	10%/Yr.	78	same	same	0.83	62	↓	↓	↓
		79	as	as	0.88	95	↓	↓	↓
		80	1	1	0.92	185	↓	↓	↓
		81			0.98	327	↓	↓	↓
		82			1.03	561	↓	↓	↓
4.	$1.00 +	1977			2.05	- 8	III	125	75
	10%/Yr.	78	same	same	2.18	-21	↓	↓	↓
		79	as	as	2.31	-37	↓	↓	↓
		80	2	2	2.44	-51	↓	↓	↓
		81			2.58	-58	↓	↓	↓
		82			2.74	-51	↓	↓	↓

TABLE D-II (CONTINUED)

DATA FOR HYDROGEN FORECASTS

Case	Nominal Cost of Hydrogen Dollars	Year	Production 10^{15} Btu	Cost Dollars	Price Dollars	Cumulative Expense 10^6 Dollars	Natural Gas Scenario	Avg. Price Ready to Pay Percentage Natural Gas	Percent Switch at Equal Price
5	$1.75 + 5%/Year	1977		$2.19		38	I	100	90
		78	same as 1	2.37	same as 1	117	↓	↓	↓
		79		2.52		248			
		80		2.73		447			
		81		2.97		733			
		82		3.22		1,129			
6	$1.75 + 5%/Year	1977		2.19		20	III	100	90
		78	same as 2	2.36	same as 2	61	↓	↓	↓
		79		2.56		128			
		80		2.78		222			
		81		3.02		366			
		82		3.29		556			
7	$1.75 + 5%/Year	1977				33	I	125	75
		78	same as 1	same as 5	same as 1	100	↓	↓	↓
		79				212			
		80				386			
		81				631			
		82				976			
8	$1.75 + 5%/Year	1977				8	III	125	75
		78	same as 2	same as 6	same as 2	26	↓	↓	↓
		79				55			
		80				101			
		81				169			
		82				265			

TABLE D-II (CONTINUED)

DATA FOR HYDROGEN FORECASTS

Case	Nominal Cost of Hydrogen Dollars	Year	Production 10^{15} Btu	Cost Dollars	Price Dollars	Cumulative Expense 10 Dollars	Natural Gas Scenario	Avg. Price Ready to Pay Percentage Natural Gas	Percent Switch at Equal Price
9	$ 3.75	1977		$4.57		$ 89	I	100	90
		78	same	4.42	same	253			
		79	as	4.36	as	494			
		80	1	4.35	1	840			
		81		4.37		1,287			
		82		4.40		1,980			
10	$ 3.75	1977		4.58		62	III	100	90
		78	same	4.45	same	171			
		79	as	4.41	as	327			
		80	2	4.42	2	533			
		81		4.47		791			
		82		4.53		1,105			
11	$ 3.75	1977				83	I	125	75
		78	same	same	same	235			
		79	as	as	as	463			
		80	1	9	2	776			
		81				1,185			
		82				1,702			
12	$ 3.75	1977				50	III	125	75
		78	same	same		135			
		79	as	as		254			
		80	2	10		406			
		81				592			
		82				812			