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UNDERGROUND HYDROGEN STORAGE

FINAL REPORT

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MASTER

December 1979

Work supported by the
DIVISION OF THERMAL AND MECHANICAL STORAGE
OFFICE OF ADVANCED CONSERVATION TECHNOLOGIES
UNITED STATES DEPARTMENT OF ENERGY

DEPARTMENT OF ENERGY AND ENVIRONMENT
BROOKHAVEN NATIONAL LABORATORY
UPTON, NEW YORK 11973

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BNL 51275
UC-94d
(Energy Storage-Chemical - TIC-4500)

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Under Subcontract No. 453439-S

December 1979

Prepared for the
ENERGY STORAGE AND CONVERSION DIVISION
DEPARTMENT OF ENERGY AND ENVIRONMENT

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UNDER CONTRACT NO. DE-AC02-76CH00016 WITH THE
UNITED STATES DEPARTMENT OF ENERGY

DIVISION OF THERMAL AND MECHANICAL STORAGE

ACKNOWLEDGMENT

The Institute of Gas Technology served as prime contractor on this program, with substantial support from Dames and Moore (subcontractor) and four participating gas utilities: Texas Gas Transmission Corp., Northern Illinois Gas Co., Transco Energy Co., and Southern California Gas Co. IGT would particularly like to express its appreciation to N. Rudd, R. Winar, C. Kunz, F. Lewis, C. Nelson, J. Kean, R. Detamore, and P. Cunningham for their cooperation and support.

Printed in the United States of America
Available from
National Technical Information Service
U S Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
Price Printed Copy $16 00, Microfiche $3 50

EXECUTIVE SUMMARY

In an extensive investigation of the technical and economic feasibility of storing hydrogen gas in underground reservoirs, we studied a depleted field, an aquifer, a salt cavern, and an excavated rock cavern. The only major technical limitation is hydrogen embrittlement, which at present, restricts reservoir pressures to 1200 psi or less. An economic methodology was developed to predict the cost of service for hydrogen storage. This methodology was verified and tested on natural gas storage. Costs of service for hydrogen ranged from 26% to 150% of the cost of the gas stored.

Background

The first successful underground storage of natural gas was accomplished in Ontario, Canada, in 1915 in a partially depleted gas field. As of 1977, there were 385 natural gas storage resevoirs in the United States with a total storage capacity of 7.2 x 10^{12} CF. Of these 385 reservoirs, about 52 are aquifers, about 15 are salt caverns, 1 is an excavated mine, and the remainder are depleted gas or oil fields. Each of these field types has a different geological distribution throughout the United States. Aquifers exist mostly in the Midwest, salt caverns are in the Great Lakes region and along the Gulf Coast, and depleted fields are scattered among 26 states.

In addition to natural gas, other fluids have been successfully stored in underground reservoirs. Liquified gases have been stored in excavated and solution-mined caverns since 1951. Hydrogen gas has been successfully stored in solution-mined salt caverns in England by Imperial Chemical Industries at Teeside. This facility utilizes three brine-compensated caverns to store hydrogen at 750 psi at a depth of 1200 feet. In a reservoir near Beynes, France, Gaz de France operated a storage aquifer for hydrogen-rich (50% to 60%), low-Btu manufactured gas from 1956 to 1972. The field was successfully converted to natural gas storage in 1973. Helium has been stored by the U.S. Geological Survey in Bush Dome near Amarillo, Tex., since 1960.

Modes of Storage

Facilities for the underground storage of gases fall into two categories: 1) porous media storage, in which the gas occupies the naturally occurring pore space between mineral grains or crystals in sandstones or porous carbonates, and 2) cavern storage, in which the gas is contained in excavated or solution-mined cavities in dense rock. Porous-media storage, either in partially depleted oil or gas fields or in aquifers, accounts for most underground storage facilities for natural gas. Natural gas is stored in solution-mined salt caverns and in one excavated cavern. Although no excavated caverns have as yet been developed specifically for the storage of natural gas, they are widely used for the storage of propane and other hydrocarbons in liquified form. Because a supernatant vapor phase invariably overlies the hydrocarbon liquids in such facilities, consideration of the facilities is appropriate for the underground storage of any gas in the vapor phase.

Although each mode of underground storage has its own set of critical characteristics, several basic considerations are common to all modes of underground storage. Both categories of storage must possess sufficient capacity and containment. These two requirements are satisfied by different mechanisms with each mode of storage. In porous media, these requirements are met by a porous reservoir rock and an overlying confining enclosure; whereas, in cavern storage, capacity is achieved from the chamber volume and containment is provided by the impermeable host rock surrounding the cavern. Several factors greatly influence the magnitude of capacity and containment for a given storage mode; chief among these is pressure. Because most rock lithologies cannot be considered to be absolutely impermeable, the limiting pressure for almost all forms of underground storage is related to the hydrostatic pressure gradient or, for purposes of approximation, 0.433 psi/ft of depth below the water table.

The overburden pressure, 1.0 psi/ft of depth, is the load of the rock column and, when approached, may result in hydraulic fracturing, or lifting, of the overburden. To remain safely below this limit, storage facilities that operate above the hydraulic pressure do not often exceed a gradient of 0.7 psi/ft of depth, which allows a margin of safety.

Most existing underground facilities for natural gas have maximum operating pressures in the range of 1000 to 2000 psi, although there are facilities operating at both extremes, from a low pressure of 160 psi to a maximum of more than 4000 psi. As the storage pressure increases, less void volume is required for a given quantity of stored gas.

When hydrogen gas is stored in an underground reservoir, the possibility of mixing with an inert base gas or natural gas that may have previously existed in the reservoir must be considered. Whether this mixing should be encouraged or discouraged depends on the use of the stored gas. For the case of hydrogen gas storage there are two possibilities. The first is that hydrogen will be a supplement to natural gas during those periods when demand is high and natural gas supplies are low. The economic analysis in the study shows the substantial influence of base-gas costs on the ultimate cost of service. If this base gas can be cheaper than hydrogen, the cost of service drops significantly. The second possibility is that hydrogen will be used as a chemical feedstock, and therefore fairly high purity requirements determine the amount of mixing that can be tolerated.

Fortunately there have been several experiences with storing dissimilar gases in porous underground reservoirs. We review them here and related the results of these experiences to storing hydrogen. The two cases discussed are the experience of Gaz de France,[17,39] which operates the Beynes Field for the storage of natural gas, and of the U.S. Geological Survey,[19,58] which operates Bush Dome near Amarillo, Tex., for the storage of helium.

We conclude that if mixing is an undesirable feature, it can be reasonably well controlled in homogeneous reservoirs of high permeability and porosity, such as Beynes Field. On the other hand, existing mathematical models are not sophisticated enough to represent reservoirs that have a heterogeneous structure and low permeability, such as Bush Dome. This shortcoming of the models can be overcome by very careful, slow injection of the gases, as well as monitoring of the gases in the reservoir by observation wells. The latter solution can be very expensive if many wells are required.

Mechanisms Controlling Containment or Loss

The same mechanisms that contain gas in porous-media storage also apply to cavern storage; however, the emphasis is different. In porous-media storage, a major concern is the intrinsic characteristics of the lithologic confining elements, paticularly their permeability and threshold pressure. In cavern storage, the site is normally selected specifically because the host rock is dense and has a very low intrinsic permeability and very high intrinsic threshold pressure. Purely hydrological confining mechanisms, such as the transport of gas in solution in water, are even less pertinent because the density and impermeability of the host rock minimize both the mobility of the water phase and the extent of gas contact with it.

The term gas "loss" requires definition, particularly as distinguished from "leakage." It is probable that there is some finite gas loss from vitually all storage reservoirs: loss through caprock, loss through solution in water, loss through solution defects in the wells themselves. Not only are these losses very minor in quantity, but they also are a predictable consequence of the environment of gas storage and the technology for its development and do not necessarily have an impact upon life or property in the surface or near-surface environment.

In terms of frequency of occurrence but not necessarily in terms of volumes of gas lost, the greatest single factor affecting the containment of gas within a storage reservoir is the wells themselves. Gas losses from this source are normally comparatively easy to detect and remedy and commonly originate from corrosion of casing or failure of the cement bond between casing and host rock. A large body of well-developed technology is available to detect and remedy such defects.

Consequences of seismic activity upon the integrity of underground storage reservoirs appear to be minimal. No report of gas loss directly attributable to seismicity, even among the several depleted field storages in seismically active portions of California, is known to exist. In general, subsurface installations in competent rock should be much less susceptible to damage arising from earthquakes than associated surface facilities such as pipelines, aboveground storage, and compressor stations.

The successful history of storing natural gas in underground reservoirs leads us to conclude that there are no overriding constraints that would prohibit the similar storage of hydrogen gas. There are properties of hydrogen gas, though, that must be considered in an underground storage operation. Those properties that imply limits to the successful storage of hydrogen are discussed below.

Technical Evaluation of Hydrogen Properties

Safety

Gas storage is regulated by the Code of Federal Regulation, Title 49, Part 192, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards."[62] This code applies to hydrogen as well as to natural gas. It will require only one significant change when a natural gas facility is converted to hydrogen: It specifies conformation to the National Electrical Code, an otherwise nonmandatory but industrially accepted standard, which will make it necessary for most electrical equipment in the facility to be replaced. A few other very minor changes may be necessary, but there appear to be no other codes or regulations that would require a hydrogen storage facility to be treated any differently from a natural gas facility. Although surface monitoring and delivery instrumentation will have to be changed to that for hydrogen service, safety requirements for the design of the surface buildings, roads, and relative location of pipelines should be no different for hydrogen than for natural gas.

Environmental Effects

The preparation of an environmental impact statement for an underground hydrogen storage facility would follow the format of impact statements currently required for the testing, construction, and operation of underground natural gas storage facilities.

The underground storage of hydrogen gas does not appear to have any significant adverse impacts upon the terrestrial or aquatic ecosystems in the vicinity of storage facilities. There are two ways that hydrogen could escape from the storage horizon and possibly reach the surface. First, gradual seepage from a storage reservoir could occur through overlying rock layers because of geological mechanisms; second, rapid leakage at damaged wellheads can occur because of mechanical leaks that usually are short-term and promptly corrected.

Free hydrogen (H_2) exists in the atmosphere in very minute amounts. It is the lightest of elements and, consequently, very buoyant, which would lead to its rapid dispersal upon entering the atmosphere. Free hydrogen is not known to be toxic to living organisms; consequently, the likelihood of significant adverse impacts arising from the release of hydrogen into the surface environments is very small.

Theoretically, imperceptible seepage by molecules of a gas from a storage reservoir over a prolonged time is possible through the confining rock layers as well as fractures in joints. Such gradual diffusion could reach the surface in undetectable volumes of gas at atmospheric pressure. Significant leakage of large volumes of gas due to geological mechanisms is rare. In one reported case, the leakage of detectable quantities of methane (CH_4) from underground storage facilities caused localized minor crop and vegetation damage. The nontoxicity of hydrogen precludes such damage in the rare event that large volumes would gradually escape through geological mechanisms.

Hydrogen could rapidly escape from the storage area as a result of a damaged wellhead; however, damage to wellheads can be repaired and avoided. A rapid release of hydrogen from an injection-withdrawal well could create a noise problem that can be minimized by locating wellheads away from residences. If the damage to the wellheads were also to ignite the hydrogen, it would produce an intense, upwardly dispersed, clean-burning flame. The only anticipated product from an accident of this type would be water vapors (H_2O). Such an accident could ignite surrounding vegetation and cause injury to anyone involved in the accident; however, the potential for such an adverse impact is considered remote. If the escaping hydrogen is not ignited, it would rapidly disperse in the atmosphere, causing no impact on the surface environment.

Hydrogen Embrittlement

The purpose of our investigation of hydrogen embrittlement is to determine whether equipment used in natural gas storage facilities is suitable for hydrogen service, and if it is not suitable, what must be changed. There is considerable industrial experience in this country in the handling of high-pressure hydrogen. Petrochemical industries, hydrogenation operations, and retailers of commodity gases all have considerable experience with hydrogen service. In addition, there is a limited base of experience in the design of pipelines for hydrogen service. Because of a lack of understanding of the basic mechanisms involved in hydrogen embrittlement, we found that present designs are based on a variety of empirically determined formulas, and no generally accepted method prevails. Industrial experience is specific to particular applications and not directly applicable to the determination of the ability of equipment designed for methane service to handle hydrogen in storage applications.

We conclude that, if the pressure at storage facilities is limited to approximately 1000 to 1200 psi, equipment currently in service at natural gas storage facilities will stand up to hydrogen service with respect to hydrogen embrittlement, with several constraints. Before the actual conversion of any given facility from natural gas to hydrogen service (regardless of the pressure level), in-place equipment must be surveyed to determine the number of flaws, hard spots, and plastic deformation. A detailed inspection of this nature may not be cost-effective at existing storage facilities. In that case, we would recommend a replacement of all welded sections subjected to pressures above several hundred psig.

Reactions of Hydrogen With Chemical Species Found in Underground Reservoirs

Sandstone, depleted fields, and mined cavern reservoirs are composed primarily of stable, nonreactive silicate minerals consisting of quartz, feldspars, and lesser amounts of garnets, spinels, and micas. However, minor sulfide, sulfate, carbonate, and oxide minerals often occur either as cementing materials or as small crystals coating the surfaces of larger grains. Because of the large amount of exposed surface area of these minerals in sandstone-type reservoirs, in excess of the quartz itself, and the large quantity of these minerals in limestone and salt reservoirs, possible reactions with hydrogen could proceed to the complete consumption of the reacting mineral. This might involve measurable quantities of hydrogen and the generation of toxic gases. We examined the possible chemical reactions, with hydrogen, of about 15 minerals common to underground reservoirs, assuming a reservoir temperature of 298 K (77°F) and a pressure of 2000 psi. Only oxygen, Fe_2O_3, and sulfur could possibly react with hydrogen. An increase in temperature of as much as 50°F would not change reaction directions, nor would reaction directions be changed by a decrease in pressure. However, these three reactions require either temperatures above those in the reservoir or catalysis.

Similar to inorganic reactions, most hydrogenation and cracking reactions require temperatures in excess of normal reservoirs. Some anaerobic bacteria are capable during fermentation processes of reducing hydrogen and sulfates to hydrogen sulfide and water, but this activity is rare in reservoirs.

Although the reactions and the case studied cannot be considered the full range of possible reactions that could occur in a reservoir, with the lack of theoretical prediction and the absence of hydrogen reactions in the Gaz de France fields, there is little evidence for serious problems with underground storage for long periods.

Economic Analysis

Methodology Development

For this project, we developed a computerized discounted cash flow analysis using constant dollars. The methodology has been modified from the standard textbook approach to reflect financing specific to utilities. This includes consideration of the "Allowance for Funds Used During Construction" (AFUDC) in the utility rate base.

In this analysis, it was assumed that base gas was financed along with facility construction; that is, base gas was purchased and financed during the construction period for delivery after construction completion. This technique of financing base gas was considered important for a study of hydrogen storage facilities because base-gas costs could be a large percentage of the facility cost and not supplied by the parent company to the storage facility.

Using information on specific fields supplied to us by operators of those fields, we determined the levelized cost of service for the storage of natural gas. The cost of service was then verified for a "typical" field operation by these operators. Satisfying ourselves that the methodology gave good values for cost of service, we varied the input parameters to determine their effect on the cost of service. This analysis was carried out for an aquifer, a depleted field, a salt cavern, and a hypothetical excavated cavern. The parameters varied were base-gas cost, physical plant cost, plant construction cost, operating cost, cost of debt, cost of equity, and the fraction of debt financed. For the four types of fields analyzed for natural gas storage, the most sensitive parameters were plant cost and cost of equity; the least sensitive were always construction time and operating costs.

Hydrogen Storage

The hydrogen storage economic analysis was carried out by using the methodology developed for natural gas storage. Each type of field was analyzed again with base-case values that reflect reasonable assumptions for hydrogen storage. These base-case values were then parametrically varied as they were for natural gas storage.

From an economic viewpoint, it appears that there will be little difference between the conversion of an existing natural gas storage facility and the development of a new field specifically for hydrogen service. The major capital cost items (wells, gas compression systems, and gathering systems) probably will need to be replaced in a conversion of an existing natural gas facility to hydrogen service. From a technical viewpoint, the same general type of system and many of the minor parts of the system will be applicable to both natural gas and hydrogen service. There appear to be no major gaps in either technology or operational procedure for underground hydrogen storage (except, perhaps, for unspecified material for very high-pressure storage fields).

Table ES-1 summarizes the base cases and cost of service for the storage of hydrogen. An annual load cycle was assumed.

Salt Cavern

The base-case plant costs and operating costs for hydrogen storage were assumed to be the same as the costs for natural gas storage. The salt cavern was assumed to be operating at 1000 to 3500 psi per annual cycle. With this assumption, the amount of throughput of the field is 1.44×10^{12} Btu/yr. Choosing $\$6.00/10^6$ Btu for the cost of the base gas and the same financial parameters as for natural gas, the base cost of service is $\$3.03/10^6$ Btu (1978 dollars). The cost of service is relatively insensitive to the cost of the base gas.

Excavated Cavern

The excavated cavern was studied for depths of 2500, 3500, and 4500 ft. The 3500-ft depth was considered as the base case, giving a base-gas volume of 1.903×10^6 SCF at a temperature of 77°F. The high cost of service derives from the high development cost of the field. By using $\$6.00/10^6$ Btu as the base-gas cost, the cost of service becomes $\$5.27/10^6$ Btu. The cost of service is relatively insensitive to the cost of the base gas.

Aquifer

Some changes in the physical plant costs primarily because of lower compressor costs for a smaller annual throughput make the analysis for hydrogen storage similar to that for natural gas storage. The cost of service is $\$6.59/10^6$ Btu. The base-case cost of service is higher for hydrogen than for natural gas because of the smaller throughput per year. Unlike the cavern storage, the cost of service is sensitive to the cost of base gas for an aquifer.

Table ES-1. BASE-CASE ECONOMICS OF STORING HYDROGEN IN FOUR TYPES OF RESERVOIRS

Item	Salt Cavern	Excavated Cavern	Aquifer	Depleted Field
Erected Plant Cost, $\$10^3$	16,400	50,000	31,900	6,660
Annual Throughput, 10^{12} Btu	1.44	2.03	1.7	0.976
Cost of Base Gas $\$/10^6$ Btu	6.00	6.00	6.00	6.00
Annual Operating Cost, $\$10^3$	350	425	1025	230
Construction Time, yr	3	3	3	3
Cost of Debt, %	10	10	10	10
Cost of Equity, %	15	15	15	15
Fraction Debt Financed	0.6	0.6	0.6	0.6
Lifetime for Economics, yr	27	27	27	27
Cost of Service, $\$/10^6$ Btu	3.03	5.27	6.59	4.47
Variation in Cost of Service, $\$/10^6$ Btu	(2.44-4.27)	(3.23-7.51)	(4.18-10.03)	(2.76-8.89)

Depleted Field

The results of the economic analysis for a depleted field for hydrogen storage assume a throughput of 0.976×10^{12} Btu/yr and give a cost of service of $\$4.46/10^6$ Btu. Two other values for throughput also were examined to determine the effect of additional compressors and wells to produce additional throughput by reducing the amount of base gas. For a throughput of 1.7×10^{12} Btu/yr, the cost of service drops to $\$2.21/10^6$ Btu and for a throughput of 2.4×10^{12} Btu/yr, the cost of service further drops to $\$1.51/10^6$ Btu. So the investment in increased compression is more than compensated for by the decrease in cost of service. All of the above were determined for developing the field as a new operation. For the case of conversion, a retrofit case was considered. Basically, some of the plant costs and line costs were eliminated. A plant cost reduction to $\$1850 \times 10^3$ gives a levelized cost of service of $\$3.34/10^6$ Btu.

Conclusions and Discussion

This study was designed to determine which of the following conclusions about underground hydrogen storage is most accurate based on technical and economic findings:

1. "Current underground gas storage practice can be used to economically and safely store hydrogen in widely available reservoirs."
2. "Further research is needed to determine whether hydrogen can be stored underground safely and economically."
3. "Underground storage of hydrogen is unsafe or not economic at this time."

We consider the first conclusion to be the most appropriate. "Current underground gas storage practice can be used to economically and safely store hydrogen in widely available reservoirs."

We found no technical constraints that prohibit the storage of hydrogen in underground reservoirs. However, certain technical questions must be addressed by appropriate R&D programs for some underground storage applications. Economic feasibility is a more complex issue. Under the best of circumstances, the development of an underground reservoir for natural gas storage requires many years for a utility. Site selection is only one of a number of decisions in a complicated process that must consider ultimate volume and throughput, pricing, FERC filings, and corporate decisions dealing with the entire company, not just the storage operation. There is no reason to believe that this process will be less involved for hydrogen storage than for natural gas storage. In particular, the most favorable storage location may not be near the source of hydrogen or near the end user. Some compromises must be made: trade-offs between convenience, cost of service, and time. Certainly, underground storage of hydrogen on a large scale is more economical than aboveground alternatives, for which storage costs of about $50/10^6 Btu have been estimated (1972 dollars)[28]. It should be clearly understood that the cost of storing gas (either hydrogen or natural gas) is very site-specific and that a range of costs is possible for each type of storage. Our economic analyses indicate that, for a given type of reservoir in a given location, the ratio of the cost of storage to the cost of the gas itself is very nearly the same whether the gas is hydrogen or natural gas. In effect, we expect the cost of storing hydrogen to be approximately equal to the cost of storing equally expensive natural gas.

Technical Results

We conclude that although all types of reservoirs cannot be used at all times for any type of service, there are no technical constraints that prohibit the storage of hydrogen in underground reservoirs. Some pressure limitations and constraints on how the fields are cycled make some fields more attractive than others for storage. However, as we have discussed previously, no mode of operation is prohibited for safety or environmental reasons. Table ES-2 summarizes the various technical conclusions of this project and gives a relative evaluation of their economic impact. The strongest technical constraint is hydrogen embrittlement, which limits the reservoir pressures to 1200 psi or less with commonly used materials of construction. Deep caverns cannot be operated economically with this pressure constraint. However, shallow salt formations can be operated in a water-compensated mode, and this type of operation may be the most attractive alternative.

Economic Results

Costs of service ($/10^6 Btu) for the storage of both hydrogen and natural gas were calculated for four specific reservoirs that are examples of four different types of storage (depleted field, aquifer, washed salt cavern, and excavated cavern). For each type of storage, a base case was developed, and the sensitivity of cost of service to various technical and economic parameters was examined. Figure ES-1 is a graphical summary of the base-case costs of service calculated for both hydrogen and natural gas storage. Our objective in preparing base cases for natural gas service was to test our model against actual practice, and somewhat different base-gas costs were assumed for each case. Therefore, the four natural gas base cases shown are not directly comparable. The hydrogen base cases can be compared, either with one another or with their respective natural gas base cases.

The contribution of operation cost, cost of base gas, and installed physical plant cost to the overall cost of service also is indicated in Figure ES-1. In all four types of

Table ES-2. SUMMARY OF PROJECT FINDINGS

Conclusion	Technical Effect	Economic Effect
Safety —		
No change in compressor station design	None	None
Compliance with Class 1, Group B Standards of National Electrical Code[42]	More stringent for natural gas; applicability must be determined	Slight to none
Hydrogen-type leak detectors	Different than those for natural gas, but already exist	Slight to none
No change in safety relief devices	None	None
Gasket and seal materials for hydrogen	Already exist	None
Environmental Effects —		
Free hydrogen not toxic	None	None
Combustion product is water	None	None
Noise from damaged wellhead could be greater than for natural gas	More remote location may be required	None
Embrittlement —		
Use of existing materials precludes pressures in excess of 1200 psi	High-pressure reservoirs are restricted	Maximum use sometimes restricted
Weldments and flaws most sensitive even below 1200 psi	Complete inspection or replacement of surface equipment	Adds significantly to cost of retrofitting field
Special compressor design and materials	Design exists, must be replaced	Hydrogen compressors cost only slightly more than methane compressor, but must be used
Chemical Reactions —		
No reactions have been identified that will consume substantial hydrogen or produce unwanted by-products	The possible reactions for each field must be determined in detail	Unknown
Purity Requirements —		
For supplement to natural gas, none	May use natural gas base gas	Reduces cost of service to use natural gas base gas significantly
For chemical feedstock, variable	Must use new reservoir or clean up the delivered gas	Variable
Mixing —		
Difficult to control in low-porosity, low-permeability reservoirs	More sophisticated reservoir model required	
Easy to control in high-permeability, high-porosity reservoirs	Moderately careful injection and withdrawal schemes; some cleanup may be required	Most economic mode; allows use of inert base
Mixing may be desirable	Deliverable monitoring to determine pricing	Requires complicated pricing scheme
Leakage —		
Frequency and magnitude of loss and/or leakage rates will not exceed those for natural gas storage	None	None

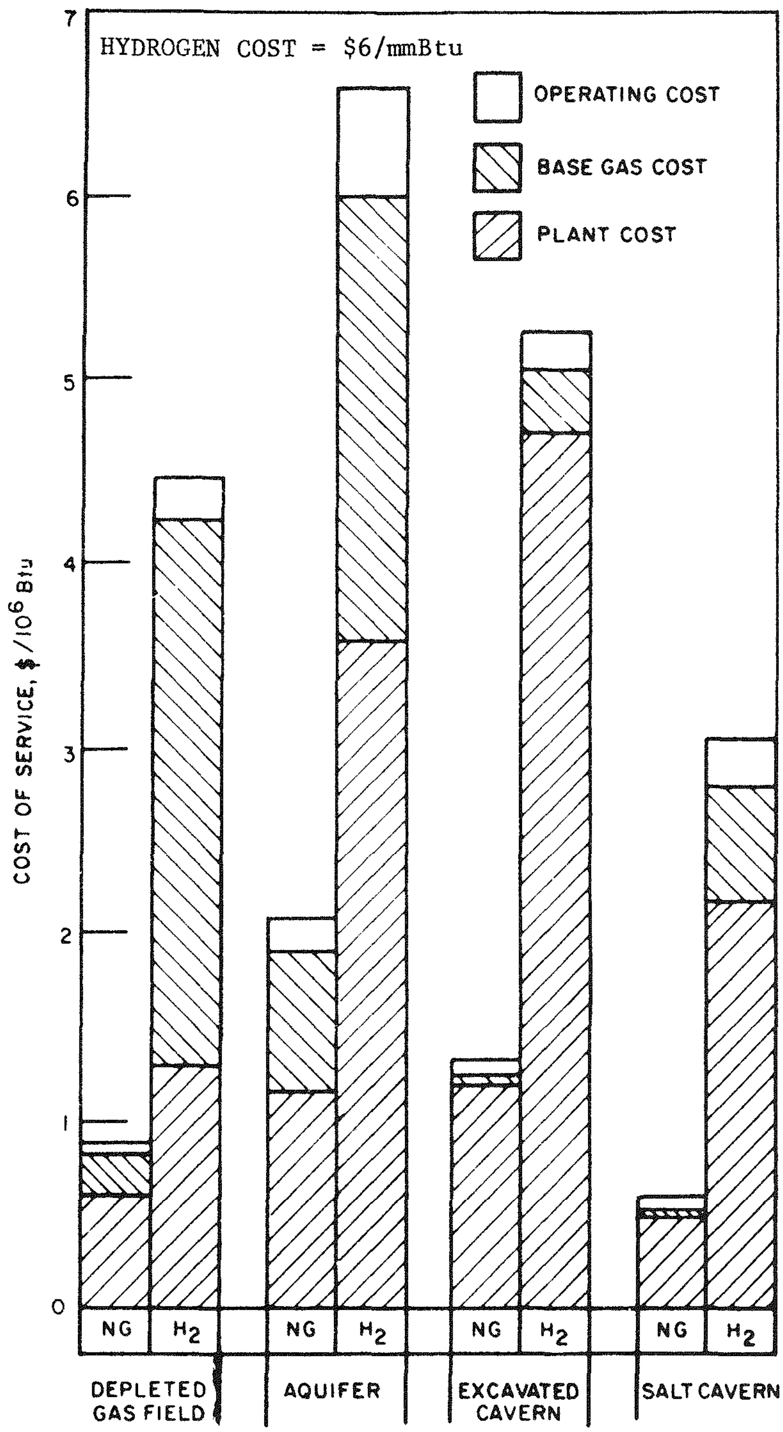

Figure ES-1. BASE-CASE COSTS OF SERVICE FOR STORING NATURAL GAS AND HYDROGEN IN FOUR TYPES OF RESERVOIRS fields, the plant and annual operating costs are very similar for either natural gas or hydrogen storage. However, because of the different volumetric heating values and compressibilities of natural gas and hydrogen, the total energy throughput for hydrogen service is a factor of two to four lower than that for natural gas service. An implicit assumption in this study is that the cost of service for hydrogen is calculated for a given reservoir with a given pore space volume. No attempt was made to compare the cost of hydrogen service based on an equivalent BTU basis to natural gas service. Therefore, the plant and operating cost contributions to the cost of hydrogen service ($\$/10^6$ Btu throughput) are from two to four times greater than the corresponding contributions to the cost of natural gas service.

The base-gas cost contributions for hydrogen service also are higher than those for natural gas service, primarily because of the large difference in the assumed costs of hydrogen ($\$6/10^6$ Btu) and natural gas (between \$0.30 and $\$1.60/10^6$ Btu). Base-gas costs constitute a smaller fraction of the total cost of service for the two cavern cases than for the two porous-media cases because the economics of cavern storage are dominated by the (plant) cost of creating the caverns themselves. The cost of service for hydrogen (or any expensive fuel) storage is extremely sensitive to the capital investment required for base gas relative to the amount of working gas, as shown by studying depleted-field storage. For three cases, the minimum field pressure was varied. The lower the minimum field pressure, the less base gas required and the higher the working gas portion of total field capacity. The absolute installed plant cost rises because of the need for more compression equipment and wells to provide deliverability at lower pressures. However, the overall cost of service decreases because a higher throughput (working gas) from which to recover investment and a reduced base-gas requirement more than compensate for the extra plant cost.

Note that this method of reducing base-gas requirements cannot be applied to all storage operations. In aquifers, or other porous media with an active water drive, a large reduction of field pressure in one season would result in water invasion, which would reduce field capacity in subsequent seasons or cycles. Also, reducing the minimum pressure in a washed salt cavern can result in salt creep and reduced cavern volume. Although lowering the minimum field pressure is not applicable to all storage options, the potential for lowering the cost of service is great enough that other methods of increasing the working/base gas ratio (raising the maximum field pressure slightly or operating caverns in a liquid-displacement mode, for example) should be investigated thoroughly.

Future R&D Recommendations

This project identified several areas that are worth further study but are beyond the scope of this project. These areas are discussed below, and specific recommendations for further research are made.

Embrittlement

This study concludes that it would not be safe to operate existing gas storage reservoirs at pressures in excess of 1000 psi because of hydrogen embrittlement in commonly used materials of construction. In addition, ongoing research in the metallurgy of hydrogen embrittlement has not conclusively pinpointed those materials that can be used in a hydrogen distribution network. Basic study must continue in this area. The upper pressure limit for a natural gas storage reservoir at this time is 5000 psi; this value is determined primarily by the geology of the reservoir formation and to a lesser degree by the costs of compression. Therefore, we encourage research in the area of hydrogen environment embrittlement in the range of 1000 to 5000 psi.

Use of Existing Hydrogen Safety Codes

The legal implications of assuming the present voluntary hydrogen safety code must be determined. If, for some reason, the present code is not applicable to underground storage, alternatives should be suggested and approved.

Effects of Supply-Market Options on Underground Storage

One assumption made in this study was that the hydrogen from storage would be used for fuel in a hydrogen-natural gas pipeline distribution system. An annual load cycle of 5 months injection-5 months withdrawal was assumed. The type of load cycle the reservoir might experience was not one of the parameters varied in this study. Each reservoir type investigated here was originally designed for a particular type of service. The integrated study of the source of hydrogen, storage reservoir, distribution system, and end use was beyond the scope of this project. Therefore, we recommend an investigation of the various possible hydrogen distribution schemes.

Economics of Supplying a Variable Hydrogen Natural Gas Mix From Storage

One of the economic difficulties immediately recognized was the problem of computing the cost of service when hydrogen might be stored in a reservoir that had previously been used for natural gas and some of the natural gas was left in the reservoir as the base gas. If the hydrogen were to be delivered to a natural gas-hydrogen distribution system, mixing would be allowed in the resevoir. (This study considered only the effect of delivering pure hydrogen; mixing was assumed not to occur.) Although analytical techniques are available to determine the composition of the gas delivered from the reservoir; the cost of service becomes exceedingly difficult to determine if cheaper natural gas is delivered with the hydrogen and the base gas eventually becomes 100% hydrogen. In addition, the time may come in the history of the field when natural gas is reinjected. These complications were beyond the scope of this project and might be worth further investigation.

Economics of a Shallow Salt Cavern Operated in a Water-Compensated Mode

No cavern in the United States stores natural gas in a brine-compensated mode. The operation at Teeside in the United Kingdom does store hydrogen in a salt cavern by using a water-compensated mode, but detailed information about that operation is not available. There are several apparent advantages to this type of operation: 1) The necessity of a base gas to provide the reservoir pressure is eliminated; 2) the reservoir can be operated at a constant pressure, which simplifies the aboveground facilities; and 3) the problems of mixing with another gas in the reservoir are eliminated. The additional costs of removing and injecting water into the cavern must be incorporated into the costs of service, however. The details of operating in this matter were not investigated, although it appeared, late in this study, as though this method could be the most cost-effective, especially if shallow salt formations were used. This particular mode of operation is especially worth further investigation.

Effect of Potential Odorants and Colorants on Hydrogen Chemical Reactions

At this time, we are unaware of particular odorants or colorants that might be added to hydrogen to make it more detectable in the same way as sulfides and sulfates are added to natural gas. The possible effects of these additives on embrittlement or reactions with reservoir minerology therefore is unknown. Future examinations into possible additives must include a consideration of their effect in underground storage operations.

Allowable Methane Content in Hydrogen in the Design of Hydrogen Burners

Although it has been established that existing methane burners can function safely and efficiently with up to 20% hydrogen in the natural gas, it has not been established how much natural gas can exist in a predominantly hydrogen system for hydrogen burners to function safely and efficiently. This is another area that requires engineering research.

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ABSTRACT

The technical and economic feasibility of storing hydrogen in underground storage reservoirs is evaluated. The past and present technology of storing gases, primarily natural gas, is reviewed. Four types of reservoirs are examined: sale caverns, excavated caverns, aquifers, and depleted fields. At technical investigation of hydrogen properties reveals that only hydrogen embrittlement places a limit on the underground storage by hydrogen. This constraint will limit reservoir pressures to 1200 psi or less.

A model was was developed to determine economic feasibility. After making reasonable assumptions that a utility might make in determining whether to proceed with a new storage operation, the model was tested and verified on natural gas storage. A parametric analysis was made on some of the input parameters of the model to determine the sensitivity of the cost of service to them. Once the model was verified it was used to compute the cost of service of storing hydrogen in the four reservoir types. The costs of service for hydrogen storage ranged from 26 to 150% of the cost of the gas stored. The study concludes that it is now both safe and economic to store hydrogen in underground reservoirs.

I. INTRODUCTION

The use of underground reservoirs for storing natural gas and other fluids has had a long and successful history. It seemed a natural extension of this history to examine the technical and economic feasibility of storing gaseous hydrogen in underground reservoirs. Should the availability of hydrogen become great enough to warrant large-scale storage, either as part of a hydrogen delivery system or as an auxiliary storage near a manufacturer or user, alternative storage modes must be explored. At present, hydrogen is stored as a compressed gas or as a liquid. The costs for these modes of storage are exceedingly high ($50/$10^6$ Btu). More exotic forms of storage also are being investigated, but at present none of these modes is economically attractive. Meanwhile, small experimental hydrogen demonstration projects are beginning, and it seems worthwhile to examine the possibility of storing hydrogen in the mode that the natural gas industry finds most economical.

This project is divided into two separate investigations. The first investigation (described in Section II) takes a detailed look at the technology for storing fluids in underground reservoirs. The objective of this examination is to pinpoint any characteristics of customary reservoir operation that would prohibit the similar storage of gaseous hydrogen. Included in this study is a description of the geographic distribution of the existing domestic gas storage operations as well as the geographic extent of formations that would lend themselves to storage of either hydrogen or natural gas. This technical study also examines hydrogen properties in the context of overall safety, environmental effects, chemical reactions with reservoir, minerology, and hydrogen embrittlement. (See Section II-B.)

The second part of the investigation develops a methodology for determining the cost of service of hydrogen storage. We first tested this methodology on four types of natural gas storage operations. Once satisfied that the methodology accurately predicts cost of service, we applied it to determine the costs of storing hydrogen in the four reservoir types.

The goal of this project is to answer the question of whether hydrogen can be stored safely and economically with one of the following answers:

1. "Current underground gas storage practice can be used to economically and safely store hydrogen in widely available reservoirs."
2. "Further research is needed to determine whether hydrogen can be stored underground safely and economically."

3. "Underground storage of hydrogen is unsafe or not economic at this time."

Although natural gas is the fluid with the largest underground storage volume, helium, LNG, propane, compressed air, and even hydrogen have been stored in underground reservoirs in the past. There are two categories of storage: porous media storage and cavern storage. Porous media considered here are primarily sandstone formations that originally contained water and are called aquifers or that contained hydrocarbons-gas and/or oil and are called depleted fields. Depleted fields are so called because all or part of the original hydrocarbons have been removed for sale.

The second category of storage, cavern storage, consists of hollow underground cavities formed by some mechanical means. The two primary types of caverns are solution-mined salt caverns and excavated hard-rock caverns in granite or coal formations. Cavern storage requires significant capital investment for creating the cavity in addition to the cost of developing the aboveground facilities at any storage operation.

Of the gas that goes into a storage reservoir, not all comes out during an injection-withdrawal cycle. The gas that remains is called the cushion gas, or base gas; it is the amount of gas that must remain in the reservoir to maintain the minimum reservoir pressure. In general, it is more economic to leave some gas in the reservoir than to invest in the additional pumps and compressors to completely empty the reservoir. This amount of base gas can make up to two-thirds of the storage volume. For an expensive gas, this can make a significant contribution to start-up capital costs. In the later stages of this investigation, the trade-off between compressor costs and base gas costs was specifically studied from the standpoint of hydrogen storage.

The methodology for the economic analysis was developed by using the usual and customary financial assumptions that a public utility would make in determining whether to proceed with a given storage operation. The costs of service for storing natural gas in four different reservoir types then were determined and compared insofar as possible with actual costs. Because of certain assumptions in the model, the computed costs could not be exactly compared with the real costs. In particular, the model assumes an annual load cycle with 5 months of injection and 5 months of withdrawal over the entire 27-year life of the facilities. No reservoir operates under these ideal conditions. In any given year, the amount injected and withdrawn depends on the dynamics of the supply and demand of the distribution system. Despite this assumption and others, we were assured by representatives of companies that store natural gas that our computed results were "reasonable."

Several of the input parameters in the economic model could be varied independently to examine the sensitivity of the cost of service to them. The most sensitive parameters were plant cost, cost of equity, and cost of debt. Least sensitive parameters were yearly operating costs and facility construction time. The sensitivity to cost of the gas to be designated as the base gas varied from most sensitive to hardly sensitive, depending on how much that gas contributed to the initial capital costs.

The methodology then was applied to hydrogen storage for all four reservoir types. Not surprising was the finding that storing hydrogen costs a great deal more than storing natural gas, because in terms of energy units (Btu's), not as much hydrogen energy as natural gas energy can be stored in a given reservoir and the assumed cost of hydrogen to be stored was four times as great as the cost of natural gas.

In an attempt to determine whether the cost of storing hydrogen could be reduced, a computational experiment was performed. This experiment examined the trade-off in reducing the amount of base gas by increasing the compression capacity. This means that more gas could be removed during each cycle of the reservoir, but would cost more in compressor costs. We found that a very significant reduction in cost of service can be achieved by operating a depleted field in this manner.

Another approach to reducing the amount of base gas is to operate a cavern storage reservoir in a water-drive mode. This means that water is pumped in and out of the reservoir to change the reservoir volume. None of the gas in the reservoir is base gas; it can all come out in any cycle.

We conclude the report (Section IV) with a summary of the findings and recommendations for further study. Appendix B is a tabulated comparison of hydrogen and methane properties, and Appendix C is a glossary of geological terms used in this report. Appendixes D, E, and F contain the computer program for the economic analysis and the computational output for the cases studied in this project.

II. FEASIBILITY OF UNDERGROUND STORAGE OF HYDROGEN

A. Preliminary Assessment of Natural Gas Underground Storage Facilities

1. Overview of Underground Storage

a. History and Development of Underground Storage of Gases

The first successful underground storage of natural gas was accomplished in Ontario, Canada in 1915 in a partially depleted gas field. In the following year, the first successful American operation was initiated in a depleted field near Buffalo, New York. The development of storage capacity increased slowly in depleted or abandoned gas fields until after World War II. After 1946, when 78 pools were being operated in 14 states, natural gas storage capacity began to increase at a much faster rate to a total in 1977 of 385 pools in 26 states (Figure 1).[4]

Because depleted fields often are not available in areas of storage demand, the storage of natural gas in water-bearing formations, or aquifers, has become common practice. The first aquifer storage field was developed in Kentucky in 1946. At present, 52 aquifer projects are operated in 10 states. Midwestern states have the greatest number of aquifer storage fields with 22 in Illinois, 10 in Indiana, 8 in Iowa, and 4 in Kentucky. The other six states each have two or less aquifer projects. Cavern storage of liquified gas and/or natural gas accounts for about 15 operations in 4 states, and these occur primarily as dissolved cavities in salt deposits. Solution-mining of salt deposits has a long history, but the creation in the United States of a salt cavern for the storage of gases was not initiated until 1951, when propane and butane were injected underground. Storage of natural gas in solution-mined salt caverns was first completed in Michigan in 1961.

There is a wide range in the geological age of the 385 natural gas storage reservoirs in the United States (Table 1); rocks of early Paleozoic age have by far the greatest number of reservoirs, about 54%, with late Paleozoic rocks accounting for about 33%. Mesozoic and Tertiary strata contain the remaining 13% of reservoirs. This predominance of Paleozoic-age reservoirs correlates with the locations in the Midwestern states shown on Figure 2, where regional bedrock consists principally of Paleozoic sedimentary rocks within large sedimentary basins.[5]

The usage of underground storage of natural gas continues to increase because it provides for better utilization of pipeline facilities and balancing of supplies to meet market demands. Total capacity of stored natural gas in 1977 (latest data) was

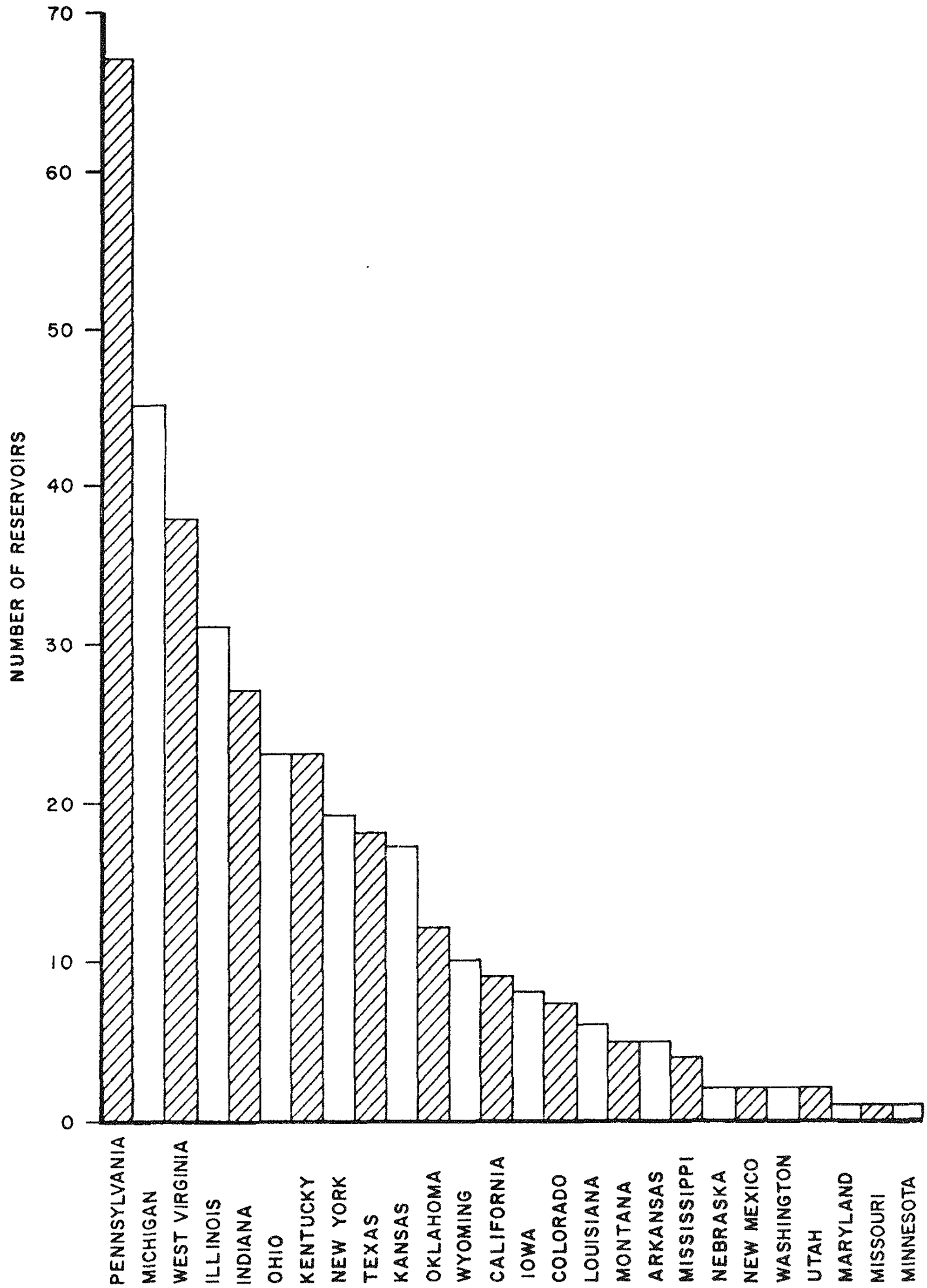


Figure 1. NUMBER OF NATURAL GAS STORAGE RESERVOIRS IN THE UNITED STATES

Table 1. SUMMARY OF RESERVOIRS BY STATE AND GEOLOGICAL AGE

	PLIOCENE THROUGH TERTIARY	CRETACEOUS	JURASSIC	PERMIAN	PENNSYLVANIAN	MISSISSIPPIAN	DEVONIAN	MISSISSIPPIAN-DEVONIAN	SILURIAN	ORDOVICIAN	CAMBRIAN	NOT REPORTED	TOTALS
Arkansas	-	-	-	-	5	-	-	-	-	-	-	-	5
California	8	1	-	-	-	-	-	-	-	-	-	-	9
Colorado	-	6	-	1	-	-	-	-	-	-	-	-	7
Illinois	-	-	-	-	3	5	4	-	2	3	14	-	31
Indiana	-	-	-	-	4	4	11	-	-	6	2	-	27
Iowa	-	-	-	-	-	-	-	-	-	4	4	-	8
Kansas	-	-	-	-	15	1	-	-	-	1	-	-	17
Kentucky	-	-	-	-	2	11	2	-	6	2	-	-	23
Louisiana	2	2	2	-	-	-	-	-	-	-	-	-	6
Maryland	-	-	-	-	-	-	1	-	-	-	-	-	1
Michigan	-	-	-	-	-	18	1	-	25	1	-	-	45
Minnesota	-	-	-	-	-	-	-	-	-	-	1	-	1
Mississippi	-	1	-	1	-	2	-	-	-	-	-	-	4
Missouri	-	-	-	-	-	-	-	-	-	1	-	-	1
Montana	-	5	-	-	-	-	-	-	-	-	-	-	5
Nebraska	-	2	-	-	-	-	-	-	-	-	-	-	2
New Mexico	1	-	-	1	-	-	-	-	-	-	-	-	2
New York	-	-	-	-	-	-	9	-	10	-	-	-	19
Ohio	-	-	-	-	-	1	1	-	21	-	-	-	23
Oklahoma	-	-	-	1	10	1	-	-	-	-	-	-	12
Pennsylvania	-	-	-	-	-	5	53	-	1	-	-	8	67
Texas	1	3	-	1	9	2	-	-	-	-	-	2	18
Utah	-	2	-	-	-	-	-	-	-	-	-	-	2
Washington	2	-	-	-	-	-	-	-	-	-	-	-	2
West Virginia	-	-	-	-	1	19	17	1	-	-	-	-	38
Wyoming	1	7	2	-	-	-	-	-	-	-	-	-	10
TOTALS	15	29	4	5	49	69	99	1	65	18	21	10	385

Reference: American Gas Association, 1978, The underground storage of gas in the United States and Canada: Twenty-Seventh Annual Report on Statistics, Committee on Underground Storage.

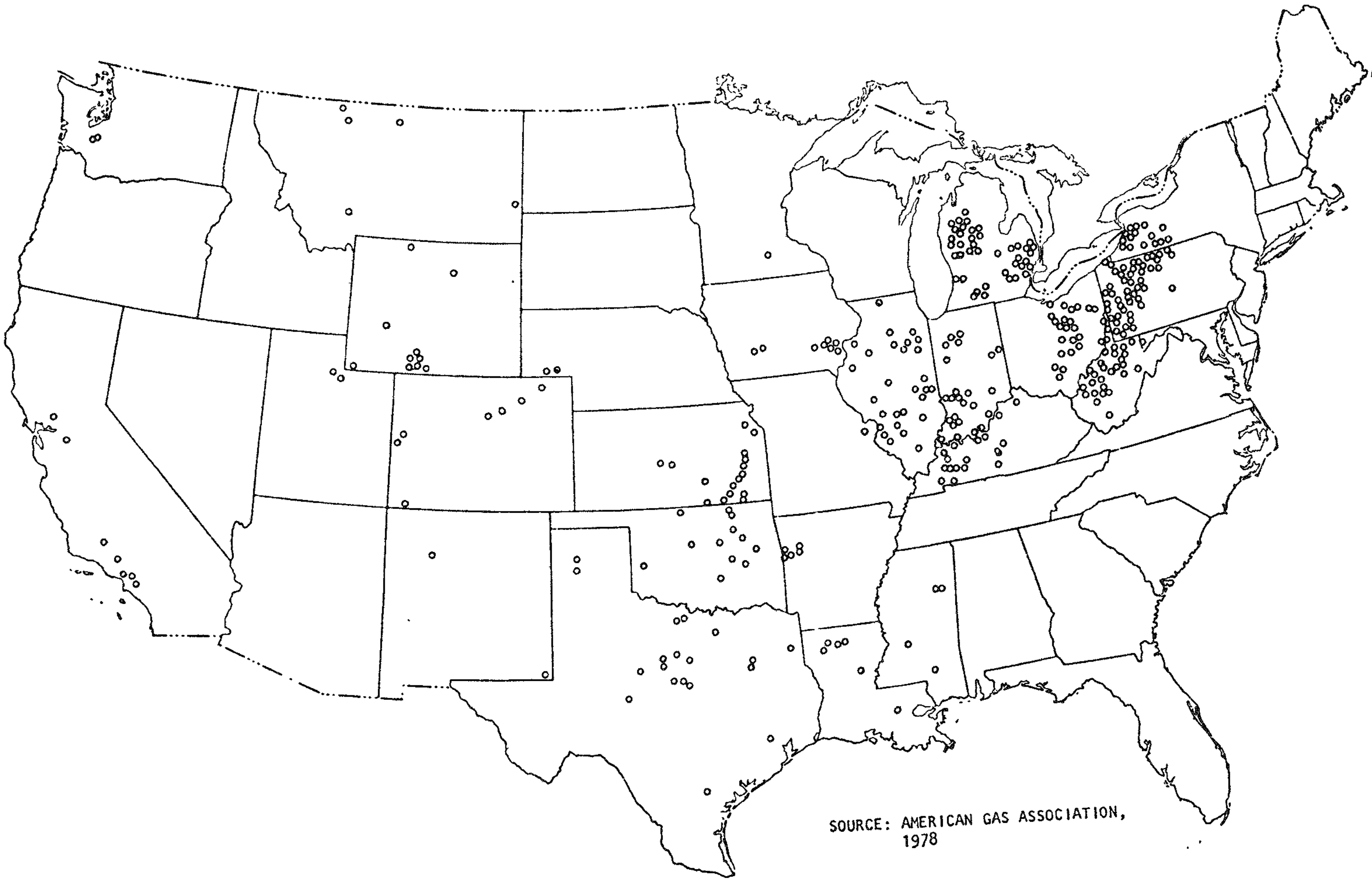


Figure 2. LOCATION OF UNDERGROUND GAS STORAGE RESERVOIRS IN THE UNITED STATES IN 1977

7.2 trillion CF including base gas. Figure 3 shows the distribution of total natural gas reservoir capacity within the 26 states that have storage projects. Nearly two-thirds (65%) of the 264 storage reservoirs whose capacity is reported by the American Gas Association[5] have storage volumes ranging from 1 to 10 billion CF (Figure 4). In 1977, 85 companies operated underground storage facilities that have a total capital investment worth $2.3 billion.[4]

Developments in underground storage of natural gas have been paralleled successfully by the underground storage of other gases. Helium was first injected into the Bush Dome structure of the Cliffside Field, near Amarillo, Texas, in 1945 by the U.S. Bureau of Mines. Helium-bearing natural gas is processed, and extracted helium is injected into Bush Dome. Crude helium injection was begun in 1963. Crude helium is a mix of helium (72%) and nitrogen with methane and hydrogen constituents. As helium demand increases, crude helium will be withdrawn, purified, and sold. Since 1973, a static storage situation exists with injection and withdrawal quantities in relative balance each year. (Section A-2-e discusses Bush Dome further.)

Storage of liquified gases in underground caverns has been accomplished since 1951 by utilizing both excavated and solution-mined caverns. Cavern storage of hydrocarbons has become an established and accepted practice, and many major petroleum production and transmission companies have developed or are investigating underground storage facilities. Numerous solution caverns have been formed in salt domes along the Gulf Coast area of Texas, Louisiana, and Mississippi for the storage of liquid ethylene, propylene, butane, and propane.

The underground storage of compressed air originated in 1910 in the Striberg Mine, Sweden; this practice is still in operation. The application of a sealed rock chamber for the storage of air to be used later as feedstock to supply drilling equipment in mines is widespread in many countries. In 1973, planning was begun for the world's first air storage gas turbine plant (290 MW) near Huntorf, West Germany, and commercial operation began in 1978. Compressed air is stored in two solution-mined salt caverns at a depth of 2300 feet and cycled from the caverns on a daily basis to the gas turbines coupled with electrical generators. Compressed air is withdrawn from underground and piped to the turbine plant during peak demand periods, the combustion air having been compressed in off-peak periods and injected into the caverns to later be available to complete the cycle.

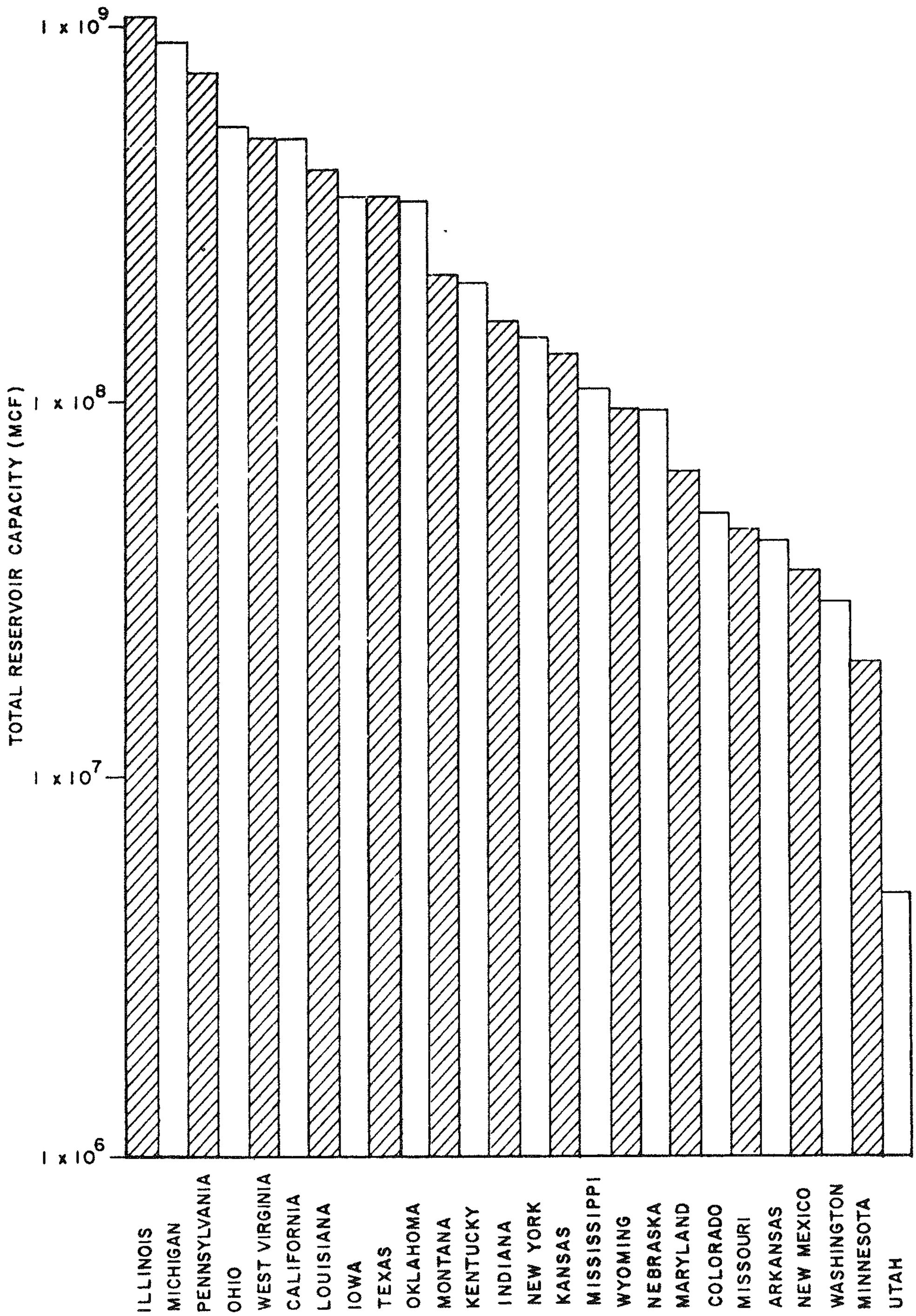


Figure 3. TOTAL STORAGE RESERVOIR CAPACITY BY STATE

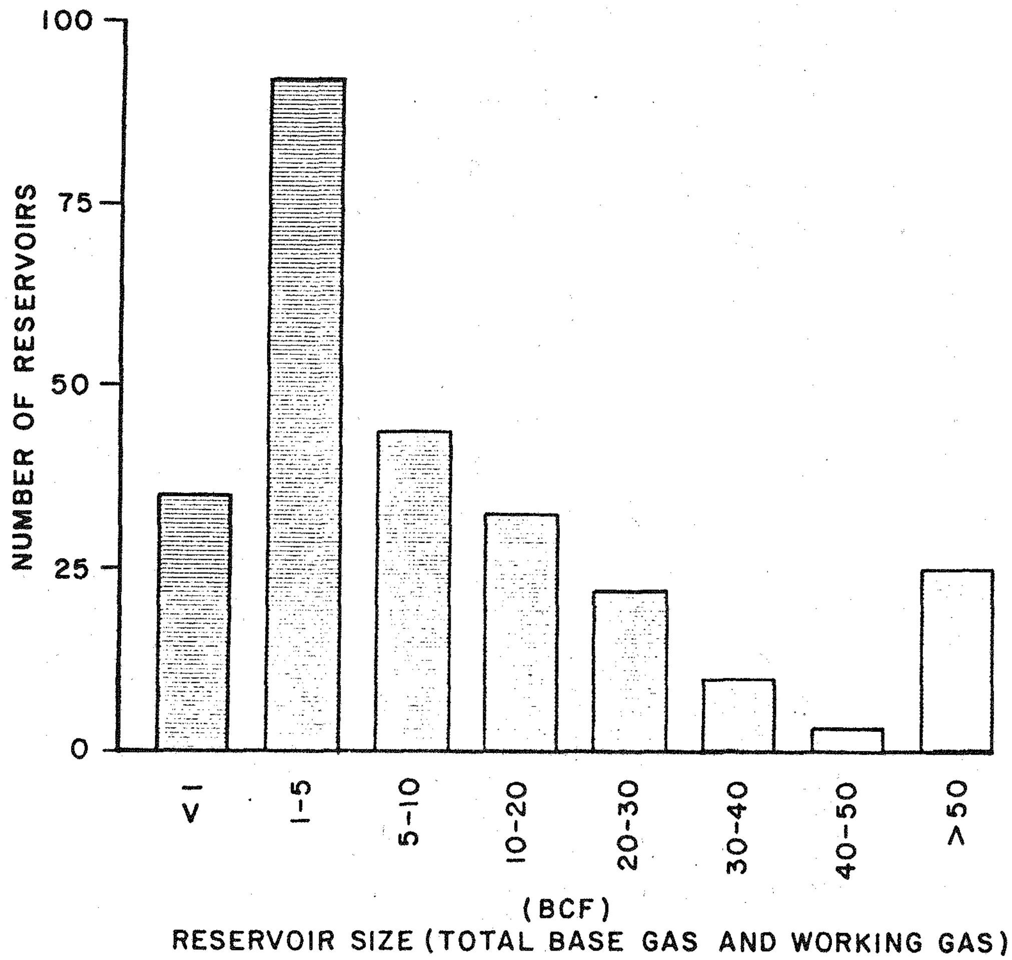


Figure 4. STORAGE VOLUME OF RESERVOIRS

b. Underground Hydrogen Storage

Hydrogen conventionally has been stored aboveground in small quantities at industrial plants where it is used in the manufacturing of petroleum products, ammonia, petrochemicals, etc. The hydrogen generally is converted into an end product at these plants, and any surplus is either burned or sold to nearby consumers. Underground storage of hydrogen in solution-mined salt caverns has been developed in England by the Imperial Chemical Industries (ICI). This storage utilizes three brine-compensated caverns to store hydrogen at 750 psi at a depth of 1200 feet. Hydrogen under pressure is injected into a brine-filled cavern and is stored by displacing the brine in the cavern. The brine then is directed into surface ponds until needed again to displace the hydrogen back to the surface. About 20,000 tons (3.27 billion CF) of 95% purity hydrogen is stored at the ICI Teeside facility. It is ultimately consumed by nearby industrial plants in the production of ammonia and methanol.

In a field near Beynes, France, Gaz de France operated an aquifer that stored hydrogen-rich, low-Btu, manufactured gas from 1956 to 1972. Storage operations changed in 1973 when the by-product gas was no longer available, and the field was converted to natural gas storage. The Beynes experience is discussed in detail in Section A-2-e.

2. Modes of Underground Gas Storage

Facilities for the underground storage of gases fall into two categories: (1) porous media storage, in which the gas occupies the naturally occurring pore space between mineral grains or crystals in sandstones or porous carbonates, and (2) cavern storage, in which the gas is contained in excavated or solution-mined cavities in dense rock (Figure 5). Porous media storage, either in partially depleted oil or gas fields or in aquifers, accounts for the large majority of all underground storage facilities for natural gas. Natural gas also is stored in solution-mined salt caverns in Mississippi and Michigan and in one excavated cavern, an abandoned coal mine near Denver, Colorado. Although no excavated caverns have as yet been developed specifically for the storage of natural gas, they are widely used for storing propane and other hydrocarbons in liquified form. Because a supernatant vapor phase invariably overlies the hydrocarbon liquids in such facilities, consideration of the facilities is appropriate for the underground storage of any gas in the vapor phase.

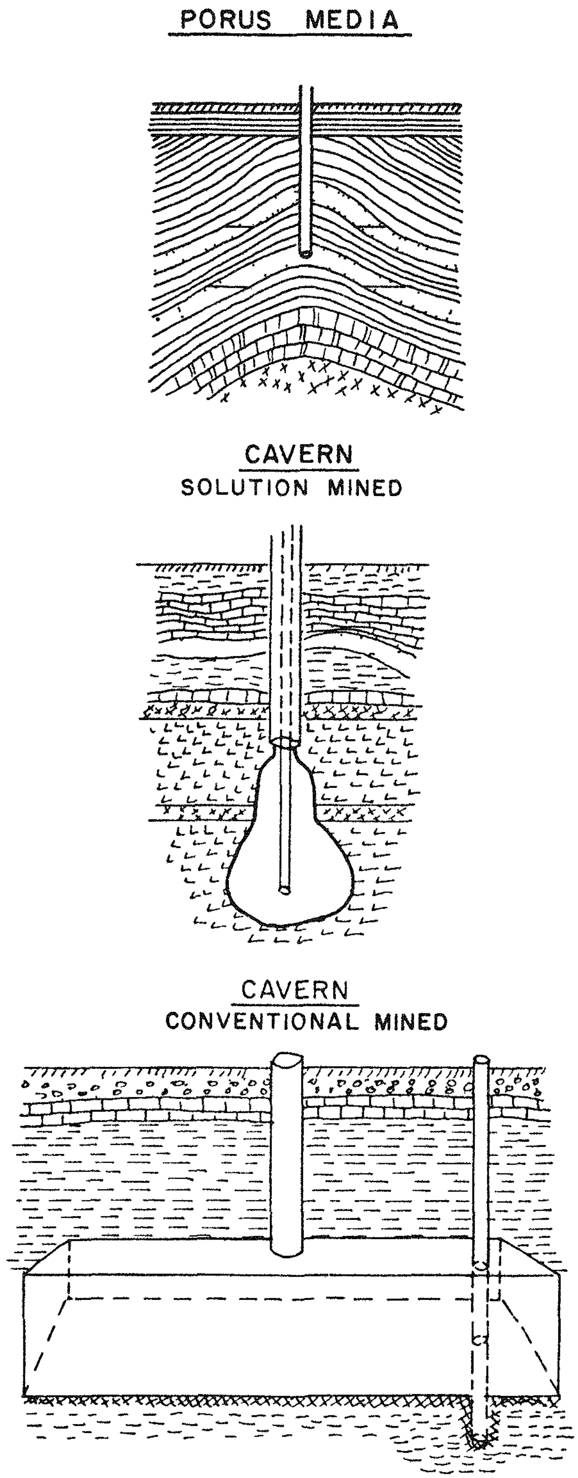


Figure 5. PRINCIPAL TYPES OF UNDERGROUND GAS STORAGE

a. Common Considerations

Although each mode of underground storage has its own set of critical characteristics, several basic considerations are common to all forms of underground storage.

Both categories of storage must possess sufficient capacity and containment for the gas in order to be successful. These two requirements are satisfied by different mechanisms with each mode of storage. In porous media, these requirements are met by a porous reservoir rock and an overlying confining enclosure, whereas in cavern storage, capacity is achieved from the chamber volume with containment provided by the impermeable host rock surrounding the cavern. Several factors greatly influence the magnitude of capacity and containment for a given storage mode; chief among these is pressure. Because most host rock lithologies cannot be considered to be absolutely impermeable, the limiting pressure for some forms of underground storage is related to the hydrostatic pressure gradient or, for purposes of approximation, 0.433 psi/ft of depth below the water table.

The hydrostatic pressure gradient is calculated by dividing the density of water (62.4 lb/ft^3, or 1 g/ml) by the area of a square foot (144 in.^{2}) as follows:

$$\frac{62.4 \text{ lb}}{144 \text{ in.}} = 0.433 \text{ psi/ft of depth} \qquad (1)$$

The hydrostatic pressure is the limiting fluid pressure and represents the weight of a column of water from the top of the water table to a particular depth. If the water stored within the rock sequence is a saturated salt brine, the increased density of this fluid (1.22 g/ml) results in a pressure gradient of 0.53 psi/ft of depth. Figure 6 shows the pressure gradient for fresh water and brine, as well as the ultimate overburden pressure gradient. The overburden pressure, 1.0 psi/ft of depth, is the load of the rock column and, when approached, may result in hydraulic fracturing, or lifting, of the overburden. To remain safely below this limit, storage facilities that operate above the hydraulic pressure do not often exceed a gradient of 0.7 psi/ft of depth, which allows for a margin of safety.

Most existing underground storage facilities for natural gas have maximum operating pressures in the range of 1000 to 2500 psi, although there are facilities operating at both extremes, from a low pressure of 160 psi to a maximum of more than 4000 psi. As the storage pressure increases, less volume is required for a given quantity of stored gas. The greater the pressure, the more gas that can be stored in a given

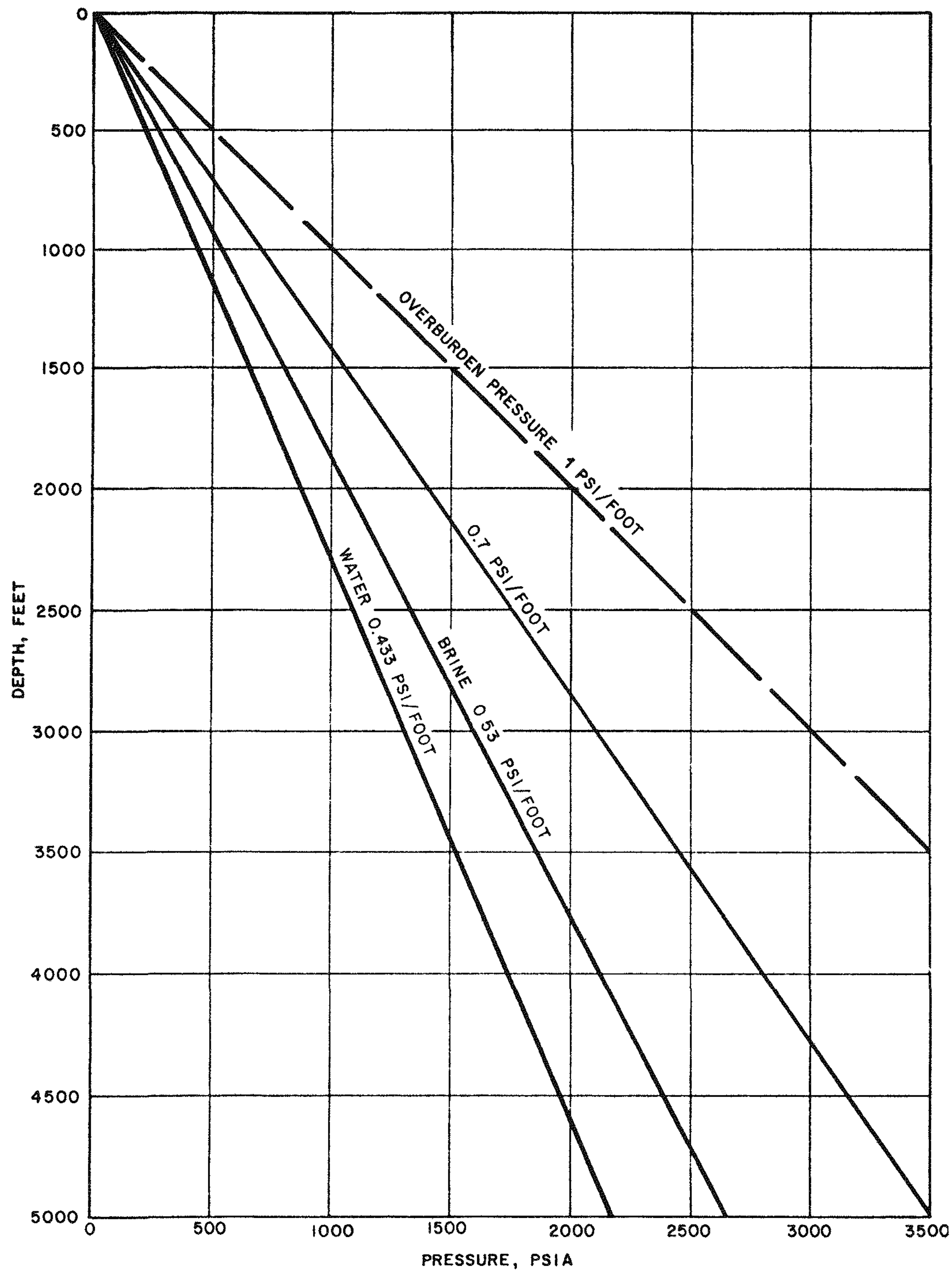


Figure 6. FLUID PRESSURE GRADIENTS IN THE EARTH

volume. This relationship is expressed by the following equation (Boyle's Law), assuming an ideal gas –

$$V_s = V_c \times \frac{P_1}{P_2} \qquad (2)$$

where –

V_s = volume of stored gas

V_c = volume of cavern

P_1 = initial pressure

P_2 = storage pressure.

On the other hand, a number of factors limit the maximum depth and pressure desirable for underground storage, including the costs of drilling wells or sinking shafts, the cost of compression, and the geothermal gradient, because high storage temperatures partially offset the volumetric efficiency gained by greater pressure. Except in the case of depleted fields, the higher cost of exploration at greater depth also is a limiting factor, whereas the depth of storage caverns in salt is limited by the rheological properties of salt.

For purposes of approximation of storage capacity, the ideal gas law is generally sufficient; the supercompressibility of natural gas also slightly favors storage pressures below 2000 psi.

Two mechanisms can provide the energy necessary to displace the gas from the reservoir. In highly permeable and porous formations of considerable lateral extent, the injection of gas drives the water down deep within the formation as the gas is compressed. During the withdrawal cycle, the gas is displaced in part by expansion and in part by reentry of the water into the previously gas-filled portion of the reservoir. This latter mechanism is termed "water drive." Its degree of effectiveness depends in part upon the rate of withdrawal. Under conditions of rapid withdrawal, gas expansion provides most of the energy required. Under conditions of slower withdrawal, the water drive may exercise a dominant effect. When the water drive is the predominant source of displacement energy, the reservoir operates at essentially constant pressure. When volumetric expansion is the primary source of energy, the reservoir pressure declines with continued production.

Many porous reservoirs, such as sand lenses, are of restricted extent, and no active water drive is present. Such reservoirs draw their displacement energy entirely from the volumetric expansion of the gas.

The same principles of displacement energy apply in cavern storage, where the cavern may intentionally be designed to operate under noncompensated or water-compensated modes. This distinction is further discussed in connection with cavern storage.

b. Requirements of Porous-Media Storage

The two basic requirements for porous-media storage are (1) a reservoir that is sufficiently porous to contain the gas and sufficiently permeable to transmit it and (2) an enclosure that provides geological and hydrological mechanisms to restrict the injected gas to a specific portion of the subsurface environment. The typical enclosure, as shown in Figure 7, consists of a caprock, most commonly shale, overlying the reservoir in a domal or anticlinal configuration that provides structural closure to limit lateral and vertical upward movement of the gas together with an underlying gas/water contact; this point of gravity separation prevents downward movement of the gas. However, all the forms of structural and stratigraphic entrapment found in naturally occurring oil and gas fields may not be conducive to storage, either in depleted fields or in aquifers.

1) Depleted-Field Storage. The oldest, most widespread, and most economical mode of storage of natural gas is the reinjection of gas into existing fields partially depleted by prior production. For natural gas storage, the use of such fields is advantageous, because it virtually eliminates exploratory cost and risk and because these fields normally contain sufficient residual gas to fulfill all or part of the base gas requirement. Conversion to storage may require only the reworking of wells and the installation of compressor facilities.

Oil and gas accumulate in reservoir traps over millions of years, commonly migrating upward from source beds that may be thousands of feet from the reservoir rock. Reservoir traps are either stratigraphic or structural and, when partially or fully depleted of natural reserves, can accept gas by injection for storage. Figure 8 shows the basic configurations of reservoir traps and the horizons of original oil and gas accumulations.

In the case of hydrogen storage, the presence of residual natural gas may be more of a problem than a benefit, because until it is fully displaced, mixing of the natural gas and hydrogen results in the production of gas of widely varying heating values during conversion. Further, the majority of depleted-field storages, particularly those in the Appalachians, operate at relatively high pressures, which can be expected to intensify problems resulting from hydrogen embrittlement.

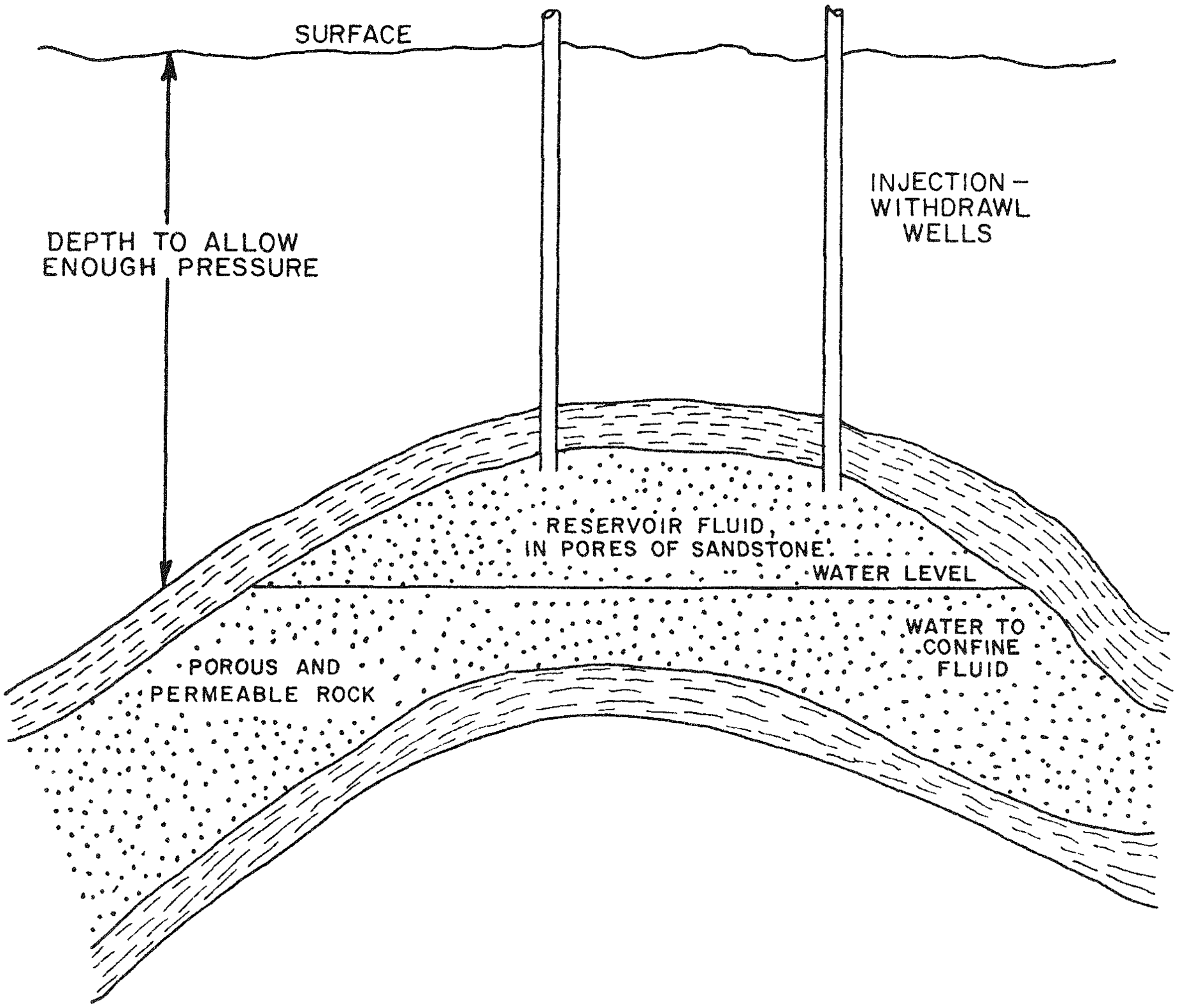


Figure 7. ELEMENTS OF STORAGE: POROUS-MEDIA STRUCTURE, POROUS AND PERMEABLE ROCK, CAPROCK, DEPTH, AND WATER SEAL

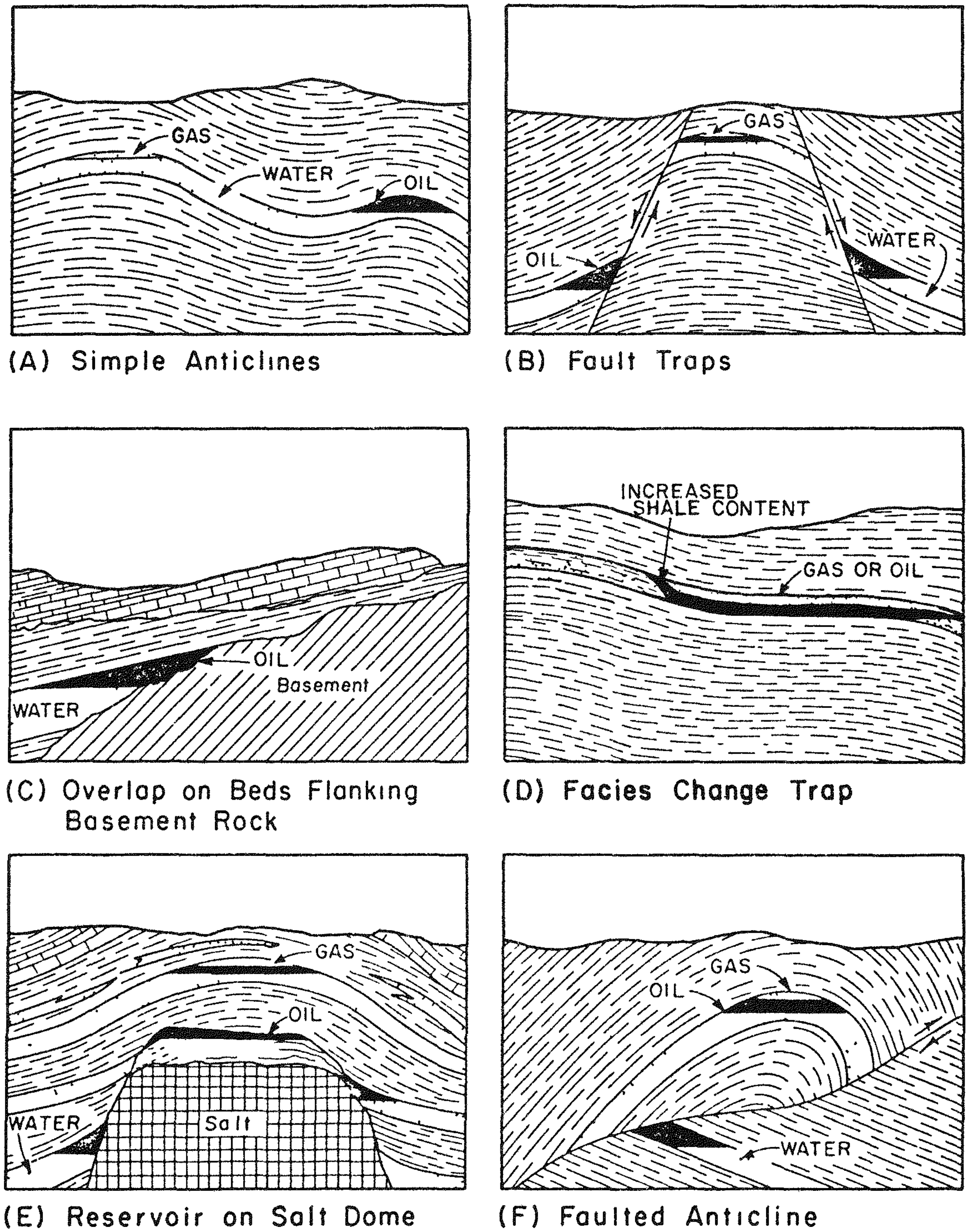


Figure 8. VARIOUS TYPES OF RESERVOIR TRAPS THAT CAN SERVE AS UNDERGROUND GAS STORAGE RESERVOIRS

The locations of major gas and oil fields within the United States, some of which may be suitable for conversion to hydrogen storage, are shown in Figure 9.

2) Aquifer Storage. The natural gas industry has found that suitable depleted-field storage opportunities frequently do not exist in desirable locations with respect to market areas and pipeline facilities, a situation that also may confront the development of hydrogen storage. In many cases, it has been possible to develop fields, similar in all respects to naturally occurring gas fields, except that in the absence of native gas, gas is injected to displace water from a portion of an aquifer. More than 50 projects have been successfully developed, the majority in the upper Midwest. The potential for aquifer storage development exists in most of the major sedimentary basins of the United States (Figure 10).

Aquifer storage development requires a major exploratory effort. In oil and gas exploration, the discovery of a hydrocarbon accumulation proves the existence of a suitable enclosure. All that remains is to determine its size and its limits. In aquifer storage, the existence of a suitable enclosure must be conclusively proven not only with respect to its structural configuration, but also with regard to the adequacy of its reservoir and caprock elements to contain gas. This is costly and not without risk, as discussed in the section on leakage.

Figure 11, a map of the Media Field in Henderson County, Illinois, shows the anticlinal structure on the top of the reservoir unit (Galesville sandstone) and the area extent and size of the field. This structure is representative of a medium-size aquifer field and has a volumetric capacity of about 50 billion CF of total stored gas. Gas would be confined within the Galesville sandstone between depths of 1310 and about 1400 ft. The overlying caprock, above the top of the depicted reservoir surface, prevents vertical migration from the reservoir, and the structural closure of the flexure limits lateral movement of gas above the −1400-ft horizon. At this depth, the enclosure flattens out at the west end of the structure and provides a potential avenue for gas migration.

Total volume of stored gas for an aquifer field such as Media can be calculated from the following equation —

$$V = (43560\ \text{ft}^2 \times \text{acre-ft}) \times \phi \times (1 - S_w)(\tfrac{1}{F}) \qquad (3)$$

where —

V = total gas content, million SCF

acre-ft $= \frac{h}{2}(A_1 + A_2)$

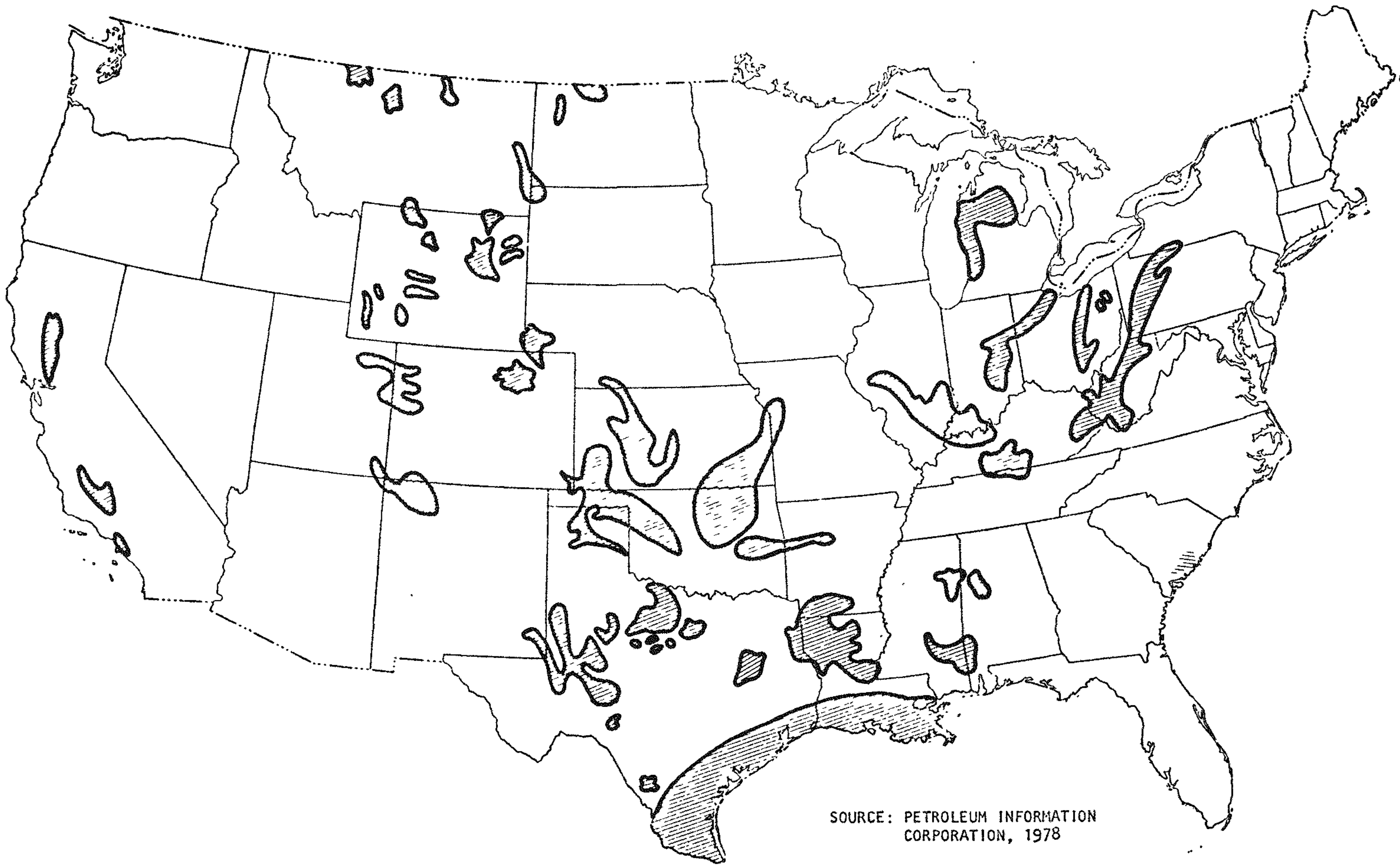
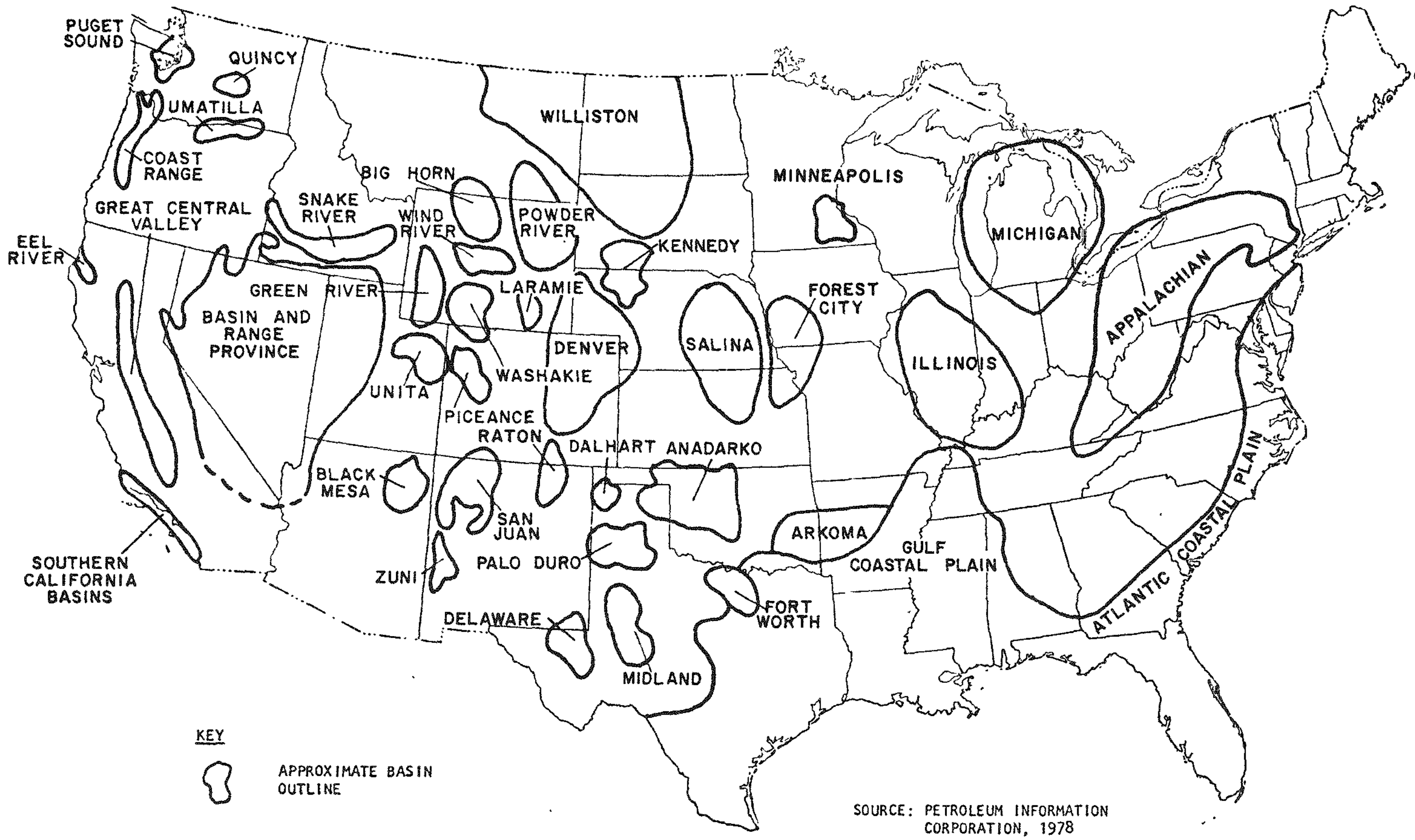


Figure 9. MAJOR GAS AND OIL FIELDS IN THE UNITED STATES



SOURCE: PETROLEUM INFORMATION CORPORATION, 1978

NOTE

BASINS REPRESENT AREAS THAT ARE GENERALLY FAVORABLE FOR AQUIFER STORAGE.

Figure 10. MAJOR SEDIMENTARY BASINS OF THE UNITED STATES

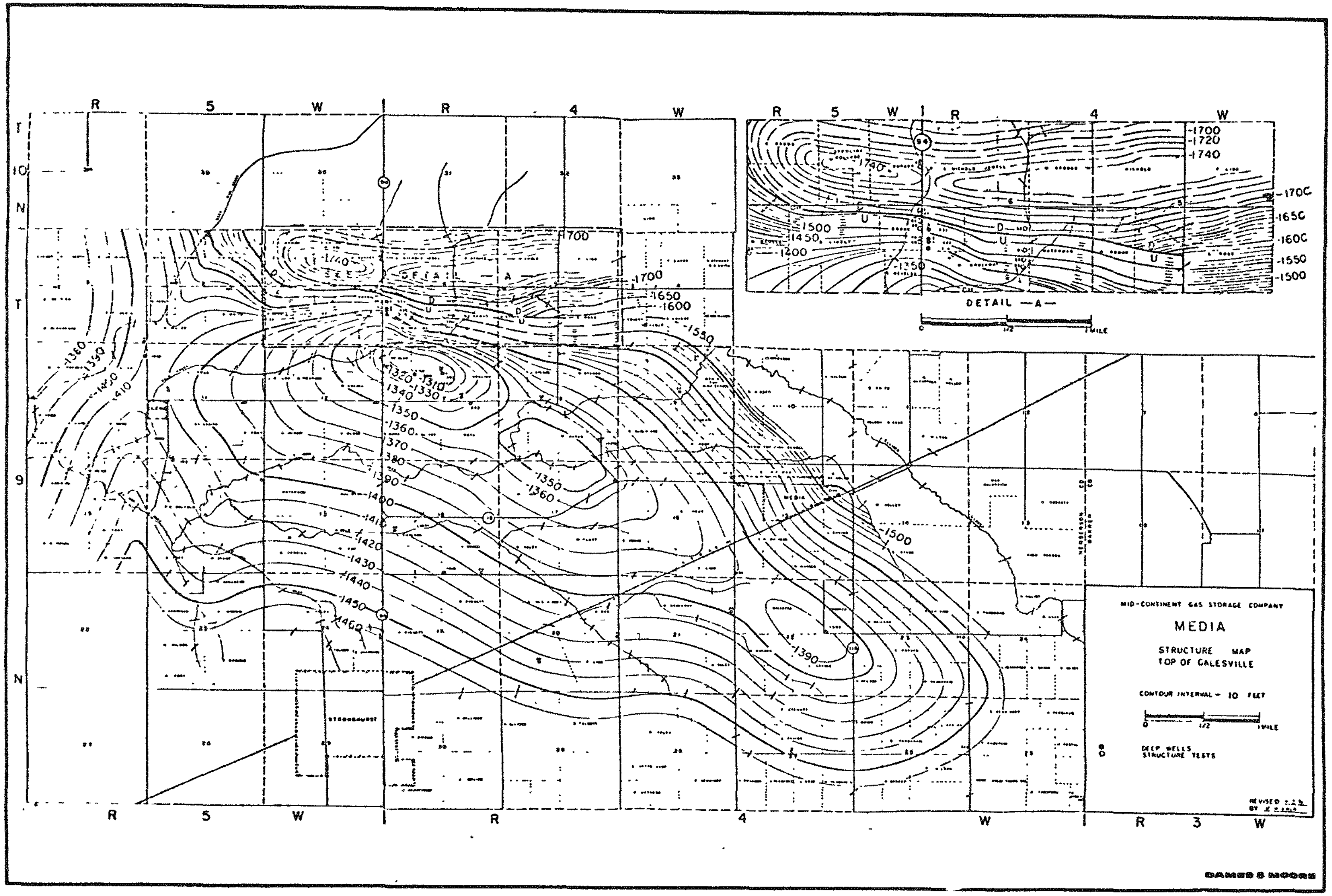


Figure 11. MAP OF THE MEDIA FIELD IN HERDERSON COUNTY, ILLINOIS

h = contour interval, ft

$A_{1,2}$ = area within successive contours

ϕ = porosity of reservoir rock, %

S_w = connate water, %

$$F = 10^6 \times \frac{P_b}{P} \times \frac{T}{T_B} \times Z \qquad (4)$$

where —

P_b = pressure base (14.73 psia)

P = reservoir pressure

T = reservoir temperature, °R

T_b = temperature base, °R

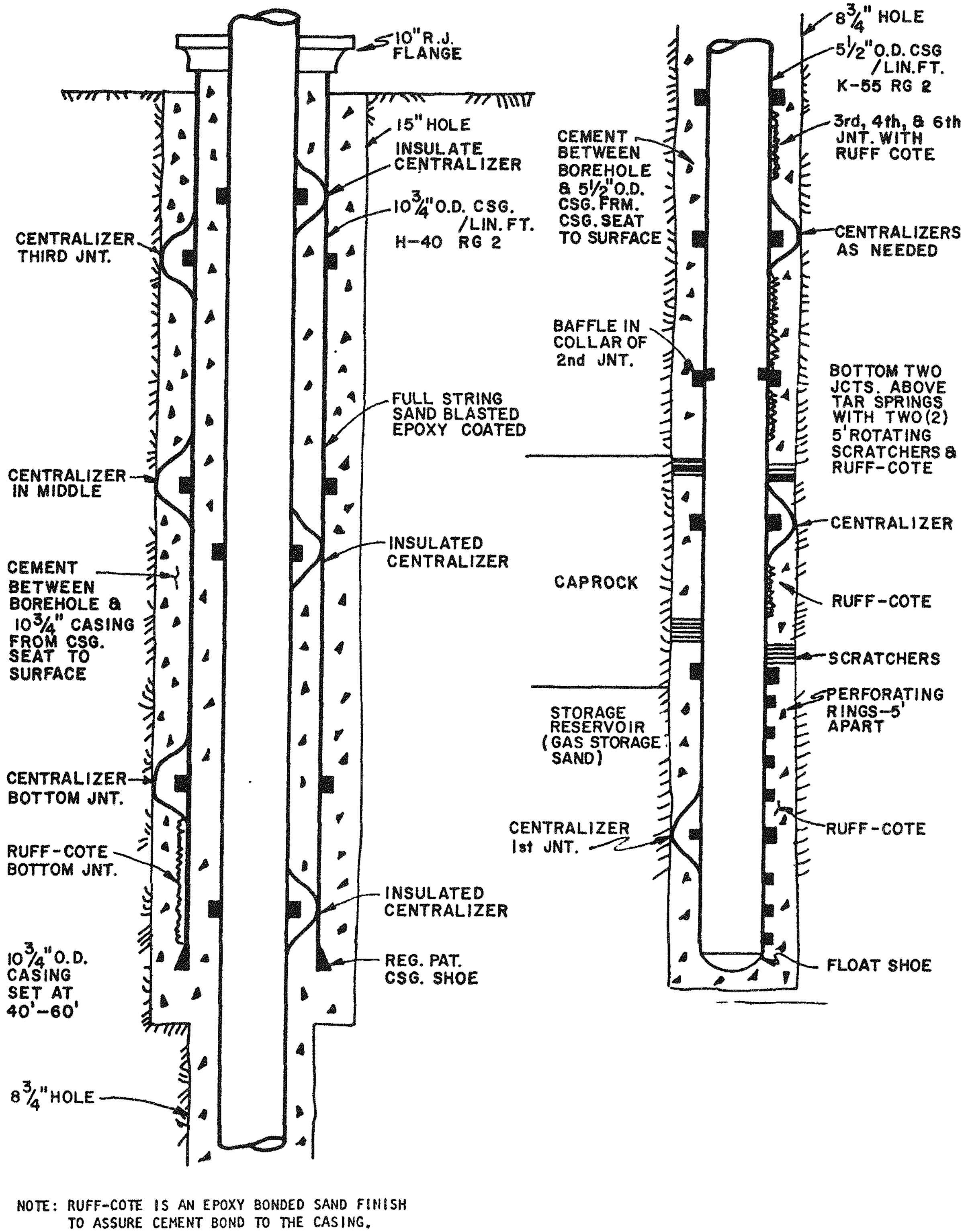
Z = compressibility factor.

Total gas volume determinations include base gas, which represents a further cost in the development of aquifer storage and is required to maintain storage volume. This base gas, which is not normally produced in a routine storage field operation, may represent from one-third to two-thirds of the total field capacity. This represents a very large investment under the current natural gas pricing structure and would presumably represent an even greater investment in the storage of hydrogen.

Proposals to use various less expensive gases as base gas have been made on several occasions and are discussed in Sections II-A-2-e and Section IV. However, theoretical considerations and both experimental and field experience suggest that the use of less expensive base gases is not practical in a storage facility subjected to frequent and substantial injection-withdrawal cycles.

Injection-withdrawal wells are spaced throughout a field and penetrate the reservoir rock. The number and spacing of wells are determined by the desired rate of deliverability and the characteristics of the reservoir. A limit is reached when the well spacing becomes close enough to cause "interference" (the productivity of one well diminishing the producitivty of an adjacent well). Figure 12 is a typical well completed in an aquifer or depleted field. These wells are designed to prevent the movement of gas between casing and borehole and to protect overlying porous formations from gas invasion if upward gas movement occurs.

3) Mechanisms Controllng Confinement or Loss of Gas in Porous-Media Storage. The basic elements necessary for the confinement of gas in porous reservoirs



NOTE: RUFF-COTE IS AN EPOXY BONDED SAND FINISH TO ASSURE CEMENT BOND TO THE CASING.

Figure 12. TYPICAL WELL COMPLETION

have been identified. Typically, the vertical upward and lateral confinement results from the lithologic barrier imposed by an impermeable stratum in a domal or anticlinal structural configuration. The underlying element of the confining system can consist entirely or partially either of a similar lithologic barrier or of the gas-water contact resulting from gravitational segregation of gas and water. This section discusses the mechanisms and limitations of these critical elements for gas containment.

a) Lithologic Confinement. Although the term "lithologic confinement" is convenient for purposes of discussion, with few exceptions it is not accurate because it excludes the role of water. Omitting consideration of fractures, joints, faults, bedding planes, and other similar "mechanical" discontinuities in rock, few rock types are absolutely impermeable. Their ability to contain gas depends partially upon a condition of relative impermeability resulting from their saturation with water. Because most rock-forming minerals are hydrophyllic, water is retained in the pore throats, the apertures between intercrystalline or intergranular pores, by capillarity. For a nonwetting phase such as gas to displace this capillary water, a positive pressure differential in excess of the capillary pressure within the pore throat is required. The pressure required for gas to displace the capillary water and enter the pores themselves is termed the threshold pressure and is inversely proportional to the radius of the pore throat:

$$P_c = \frac{2\sigma \cos\theta}{r} \tag{5}$$

where –

P_c = capillary pressure (threshold pressure), dynes/cm^2

σ = surface tension, dynes/cm

θ = contact angle, deg

r = capillary radius (pore throat radius), cm.

In finely grained or finely crystalline rocks, the pore throat diameters may be very small, resulting in threshold pressures ranging from hundreds to thousands of psi. Thus, the integrity of the lithologic confining elements, commonly called caprock, depends upon a) saturation by water and b) the diameter of the apertures between pores. Shale, many finely grained and dense carbonates, most evaporites such as salt and anhydrite, and most unweathered igneous and metamorphic rock can be expected to have pore throat diameters sufficiently small to result in threshold pressures of several hundred psi or more.

The threshold pressure is additive to the overlying hydrostatic pressure in determining the maximum confining pressure within a storage reservoir. Thus, the maximum gas pressure that can be retained by a 500-psi threshold pressure caprock at a depth of 2000 feet is approximately 1366 psi, not 500 psi. Because in most porous-media storage water under hydrostatic pressure is the confining element underlying the gas, the operating pressure must be controlled to limit displacement of the gas beyond the limits of structural closure. In such cases, the threshold pressure constitutes more of a measurement of the quality of the caprock than an actual physical limitation. In cases of totally confined porous-media storage and also in cavern storage, high threshold pressures may permit "overpressuring," exceeding the hydrostatic pressures surrounding the reservoir.

Note that, even in seemingly highly homogeneous lithologies, the range of pore sizes and pore throat diameters often is very great. Thus, it is not sufficient to consider average or typical pore throat diameters, but rather the largest, no matter how infrequently they may occur. Accordingly, the threshold pressure cannot be reliably inferred from such commonly measured parameters as permeability and porosity.

Even when the lithologic confining elements exhibit uniformly high threshold pressures and low permeabilities, their integrity can be compromised by such "mechanical" discontinuities as joints, fractures, and faults that provide avenues for gas migration completely unrelated to the intrinsic characteristics of the caprock. Joints and fractures are commonplace in almost all rock types, the only exceptions being some plastic shales and salt formations whose rheological properties either prevent or heal such physical discontinuities through plastic flow or creep. These discontinuities present a serious risk of gas migration in mined cavern storage (and are discussed at greater length in that context) but do not appear to be a significant concern in porous-media storage. Because joints and fractures, particularly the former, occur with spacings from a few inches to a few hundred feet in almost all sedimentary rocks, there would be few naturally occurring oil and gas accumulations, not to mention successful gas storage reservoirs, if they were a significant factor. Presumably the fact that porous-media storage reservoirs are commonly much deeper (thousands of feet) than storage caverns (hundreds of feet) and have lithostatic pressures an order of magnitude greater is one explanation of the great difference in effect upon confinement: Deformation of the rock under high stress commonly encountered in storage operations is adequate to close most cracks. The greater roles of joints and fractures in gas loss from caverns also may be due in part to hydrological considerations. Water entering a cavern through joints and fractures will do so at a rate controlled by the hydrostatic head and by the dimensions of the fracture system. The rate of discharge therefore can exceed the rate of recharge in the fracture system with consequent localized reduction of the hydrostatic pressure below the storage pressure. Water migrating downward into a porous reservoir does not discharge into free space but rather into a partially water-saturated porous medium that can greatly reduce its discharge rate, while the increased thickness of overlying rock may result in greatly increased discharge capacity.

Although there is little evidence that joints and fractures have contributed significantly to gas loss from porous-media storage, there are several instances of gas loss attributable to faults. Faults differ from joints and fractures in that they represent physical dislocation of one side with respect to the other. The most obvious and most serious loss of caprock integrity through faulting is when the dislocation is sufficient to disrupt the continuity of the caprock, when the caprock on one side of the fault is raised or lowered with respect to the other to such an extent that they are no longer in contact. Although such gross dislocations have been encountered in aquifer storage experience, these features are usually of such magnitude that they can be recognized in advance by careful exploratory methods. If faults of small displacement are identified even with careful exploration techniques, the potential for leakage can often be identified by pump-testing prior to the injection of gas.

Although it may be preferable not to store gas in structures whose caprock contains known faults, faults have been identified in a number of successful storage projects with no significant gas loss.

b) Hydrologic Confinement. As discussed elsewhere in this report, hydrocarbon gases as well as hydrogen are soluble to a limited degree in water. Thus, at any point in the containment system where gas is in contact with water, there is a finite gas loss into solution. In most cases, this is virtually negligible, as is evident from the fact that naturally existing gas accumulations have in many cases existed in contact with water for hundreds of millions of years without significant diminishment. Under static conditions, where gas and water are in contact in a porous medium without significant movement, the concentration of dissolved gas in water diminishes rapidly with the distance from the gas-water interface; once the water immediately adjacent to the gas accumulation has reached saturation, near equilibrium conditions exist; and the additional gas that can be lost through dissolution in water is limited to that which is lost through diffusion. However, a cyclical operation of a storage reservoir not only results in the advance and displacement of the gas-water interface, but under certain conditions also can create a pumping effect in which undersaturated water is drawn in during the gas withdrawal cycle while the saturated water is displaced during the injection cycle. Even when the field is inactive, water movement within the storage reservoir can result in the continual flow of water at the gas-water interface with a consequent increase in the rate of gas loss through solution. Velocities of water movement in storage reservoirs sufficient to make this latter mechanism of gas loss truly significant are rare.

4) Other Factors Affecting the Containment or Loss of Gas from Porous-Media Storage. In terms of frequency of occurrence but not necessarily in terms of volumes of gas lost, the greatest single factor affecting the containment of gas within a porous-media storage reservoir is the wells themselves. Gas losses from this source normally are comparatively easy to detect and remedy, and they commonly originate from corrosion of casing or failure of the cement bond between casing and host rock. A large body of well-developed technology is available to detect and remedy such defects.

The consequences of seismic activity upon the integrity of underground storage reservoirs appear to be minimal. A gas loss directly attributable to seismicity, even among the several depleted-field storages in seismically active portions of California, has never been reported. In general, subsurface installations in competent rock should be much less susceptible to damage arising from earthquakes than would associated surface facilities such as pipelines, aboveground storage, and compressor stations. Areas susceptible to seismic activity are shown in Figure 13.

5) Frequency and Magnitude of Gas Losses from Porous-Media Storage. The term gas "loss" requires definition, particularly as distinguished from "leakage." There probably is some finite gas loss from virtually all porous storage reservoirs: loss through caprock, loss through solution in water, and/or loss through defects in the wells themselves. Not only are many of these losses very minor in quantity, but also they are a predictable consequence of the environment of gas storage and the technology for its development. They do not necessarily have an impact upon life or property in the surface or near-surface environment. Even very substantial quantities of gas can be lost from the primary reservoir without harmful effects, except upon the cost of storage. A case in point is the Hersher Storage Field operated by Natural Gas Pipeline Corporation of America in Kankakee County, Ill., in which gas escaping from the primary reservoir is collected in an overlying reservoir and reinjected. The term "leakage" is reserved for those relatively rare instances of uncontrollable gas loss of such magnitude as to be a significant factor in storage economics or in environmental safety. Leakage is discussed in a later section of this report.

We have had great difficulty in addressing the frequency and magnitude of gas losses because these questions ultimately depend upon the limits of detectability of gas

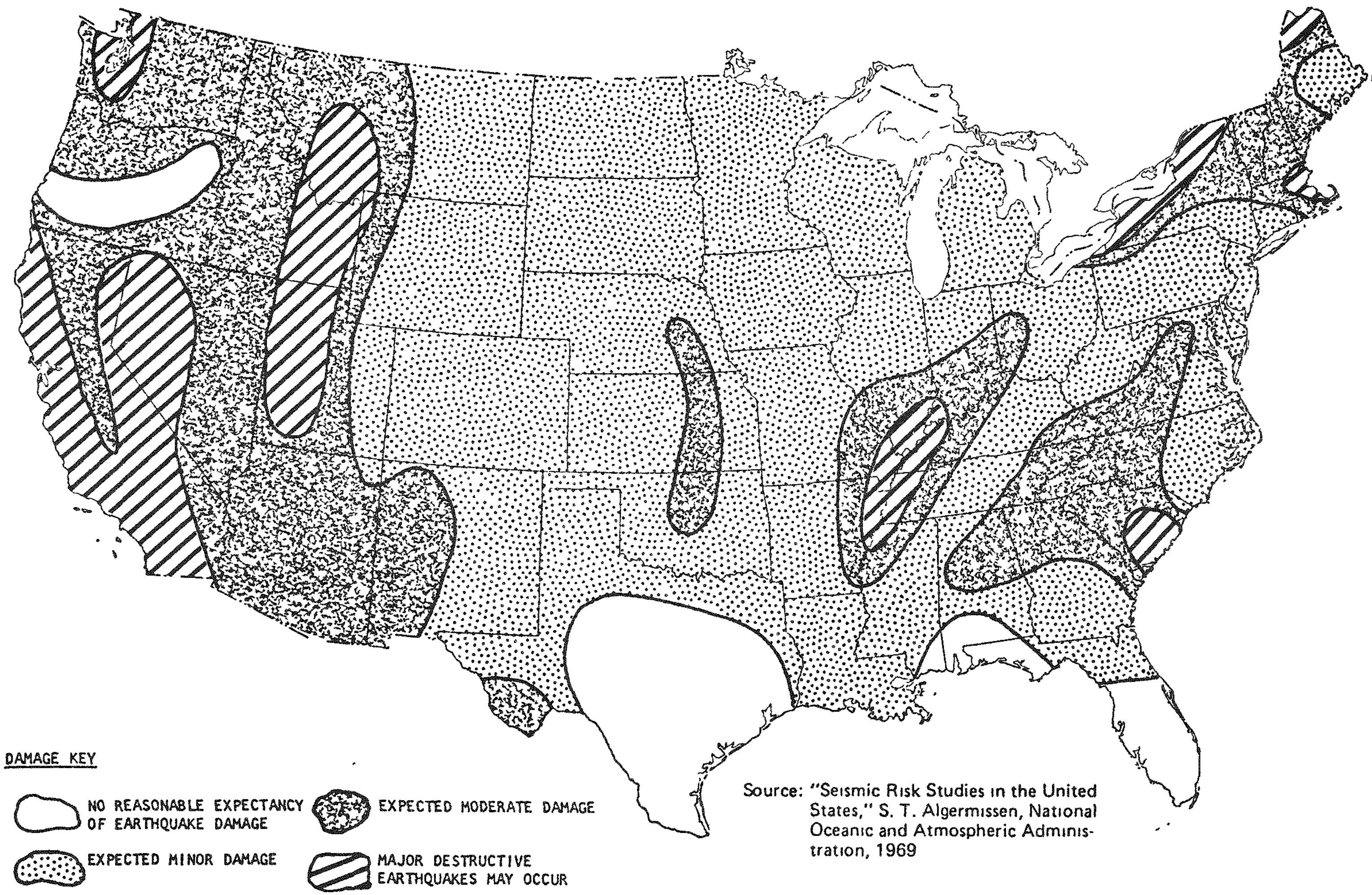


Figure 13. SEISMIC RISK MAP FOR THE CONTIGUOUS UNITED STATES

loss. In general, two methods are used to detect gas loss. The most obvious is the detection of gas outside the confines of the storage reservoir either directly or by its effect upon the pressures in superadjacent porous zones. Alternatively, it can be recognized from reductions in gas inventory as measured by various means.

Even when gas is observed outside the confines of the primary reservoir, it must be shown that the gas originated within the reservoir before loss is proven. Minor quantities of gas of both biogenic and petrogenic origin are not uncommon in sedimentary rocks, and in many instances the gas observed above and in the vicinity of porous-media storage reservoirs ultimately has been proven to have been completely unrelated to storage activity. Direct detection of lost gas is rare and frequently implies rather large-scale leakage. Indirect detection is somewhat more common, particularly when applied to minor gas losses associated with injection-withdrawal wells. Very often the identification of gas behind the casing by gamma ray-neutron logs also indicates casing failure or more commonly failure of the cement bond. Also, observation wells are often used to measure the pressure in superadjacent formations at various points above the storage reservoir. Upward movement of gas can be reflected in increased observation-well pressures, although the sensitivity of this technique is highly dependent upon hydrologic characteristics of the zone in which these wells are completed and upon their location with respect to the storage reservoir.

The detectability of gas loss inventory measurement is highly variable and depends upon the methods employed. Our study of inventory measurement practice suggests that very careful pressure measurement during prolonged shut-in periods can result in an accuracy of gas inventory measurement of substantially less than ±1%. On the other hand, in some depleted fields in which the reservoir volume or configuration is not well understood and in which gas inventory is determined only by metering the gas injected and withdrawn, the limit of detectability can be as great as ±5%.

Barring direct observation of gas outside the confines of the storage reservoir and assuming gas inventory measurements made in accordance with the best practices of the natural gas storage industry, gas losses of the order of 0.1%/yr probably represent the lower limit of detectability and only then after continuing for a period of several years. In terms of a field of 10-billion CF capacity, an annual loss of 10 million SCF probably would not be recognized for several years.

The frequency and origin of losses from depleted storage fields are particularly difficult to assess. The operators of such fields frequently depend upon the historical integrity of the field through geologic time as a guarantee of gas containment;

observation wells are less common and inventory measurements seem less accurate compared to the practice of aquifer storage operators. Further, when gas is observed in overlying formations in the vicinity, it can be either native gas in the sense of primary entrapment or gas that has escaped from the depleted reservoir either in the geologic past or in the early development of the field for gas production. The majority of gas losses in depleted fields apparently are associated with casing failures or other defects of the wells themselves. Note that the large plurality of depleted storage reservoirs are located in the Appalachian region and that many of these fields contain very old wells. Thus, well failures are to be anticipated not only because of the age of the wells themselves, but also because many of these wells were drilled prior to the development of modern completion technology.

The argument that the integrity of depleted-field storage reservoirs is guaranteed because they successfully held gas throughout geologic time is not wholly convincing; many of these reservoirs were not completely filled with respect to their structural closure at the time of discovery. Although it is possible, and in many cases probable, that underfilling simply reflects an undersupply of gas at the time of entrapment, it is also possible that these fields lost gas until the reduced gas pressure fell below the threshold pressure of the caprock. Therefore, these fields are in a condition of delicate equilibrium, susceptible to renewed loss upon increase in storage pressure, or loss may have been continuous from the time of entrapment to the present. Examples of both latter alternatives are known, but the extent to which they exist among depleted storage reservoirs is not.

Notwithstanding the above, the presence of native gas in depleted fields permits, at the outset, a greater degree of confidence in the competency of the caprock than is possible in aquifer storage. Accordingly, caprock evaluation is a critical part of aquifer storage development and customarily includes detailed structural and stratigraphic studies, extensive coring and laboratory analysis, and pump-testing. Despite the care that the gas industry applies to such pre-injection studies, there does appear to be a higher incidence of gas loss resulting from caprock defects associated with aquifer storage. Although such losses have resulted in field abandonment in some cases, others continue to operate satisfactorily despite caprock problems. In some cases, it is difficult to be certain whether caprock losses are occurring, and authorities differ upon the interpretation of data.

Gas losses do not necessarily make porous media storage unfeasible or unsafe. In some cases such as the Hersher Field, the gas can be gathered and recycled in an overlying secondary reservoir. In other cases, there is no evidence that gas that has escaped through the caprock has ever approached the surface or near-surface environment, presumably being retained in secondary traps and/or having gone into solution in water in overlying horizons. The magnitude of gas losses ranges from trivial or undetectable to those which are economically unsupportable or potentially dangerous to life and property and depends upon the specific geological and hydrological characteristics at each storage site. Generalizations about probable frequencies and magnitudes of gas loss cannot be made on the basis of either geographical location or geological environment. On the other hand, with the advantage of hindsight, many instances of serious gas loss should have been recognizable, at least to the extent of identifying a high level of risk, with more careful and thorough exploration techniques and testing programs.

c. Cavern Storage

Although relatively rare in the storage of natural gas, cavern storage offers several significant advantages. Its suitable host lithologies for mined caverns include thick shale sequences, salt, and igneous and metamorphic rock, the latter two being best suited for deep, high-pressure storage. Regions in which these host rock types can be anticipated are shown on Figures 14, 15, and 16. Note from these figures that one important advantage is that cavern storage is geologically feasible in many areas where porous-media storage is not. This is particularly true in a number of areas of high energy consumption such as New England, the Atlantic seaboard, and the Pacific Northwest.

An additional advantage is that there is no inherent limitation on deliverability, as opposed to porous-media storage where withdrawal rates are limited by the permeability of the reservoir formation and the number of wells available. Finally, because cavern storage involves only nominal quantities of nonproducible gas, increasing gas costs make it increasingly economically attractive when compared to the high base-gas costs in porous-media storage.

The two approaches to the design of a gas storage cavern are constant pressure and variable pressure. Constant-pressure design requires that the cavern be kept partially filled with water. The pressure is kept constant by the hydraulic head of water that connects the water in the cavern to a reservoir at the surface. During withdrawal periods, water is allowed to enter the chamber and displace the stored gas. The water level is lowered in the cavern during gas injection, and water is returned to the surface reservoir through the shaft that connects the cavern with the reservoir (Figure 17a). This water-compensating pressure system of cavern storage operates with a minimal

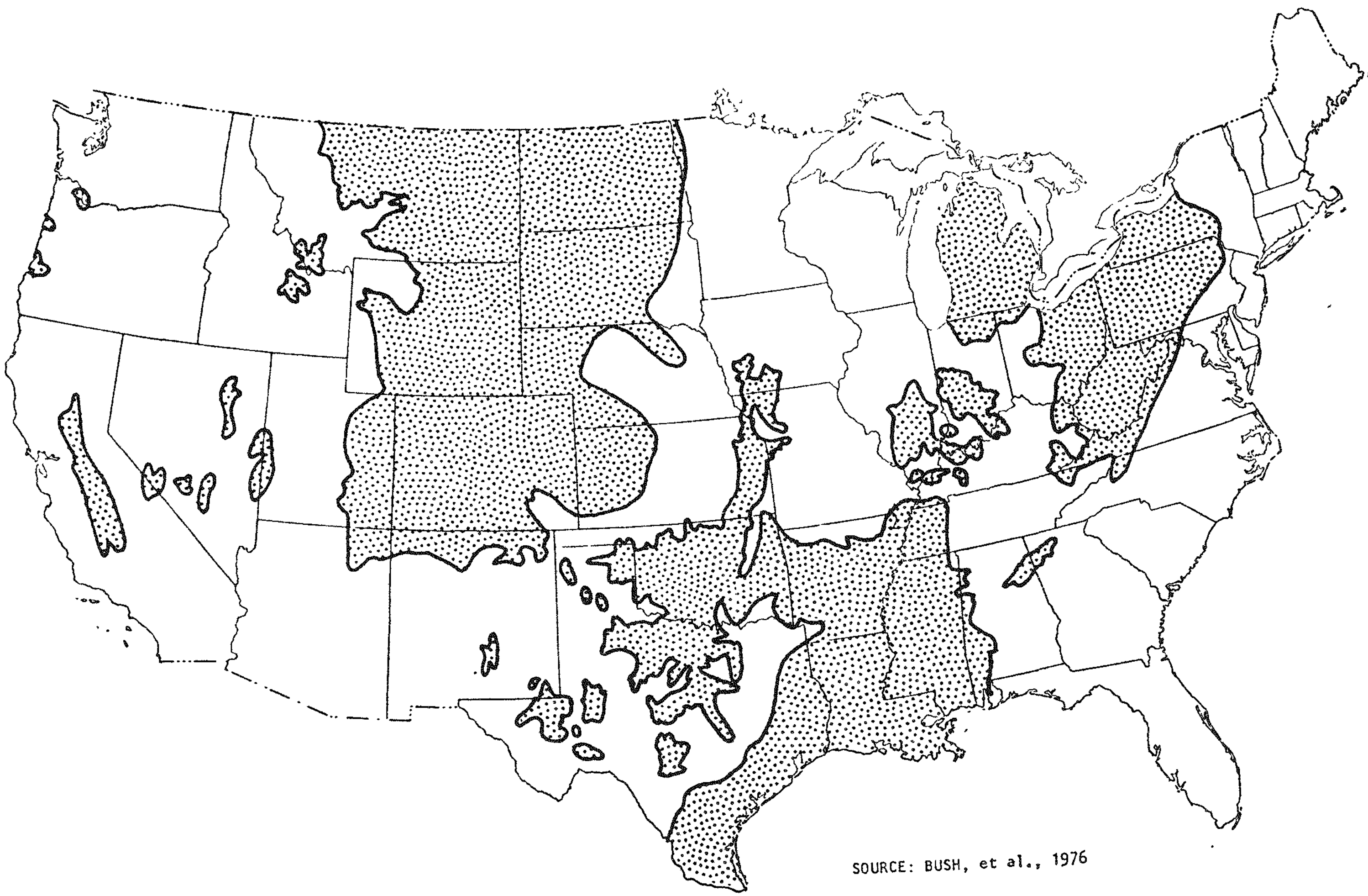


Figure 14. AREAS UNDERLAIN BY MORE THAN 500 FEET OF SHALE IN IN UNITED STATES

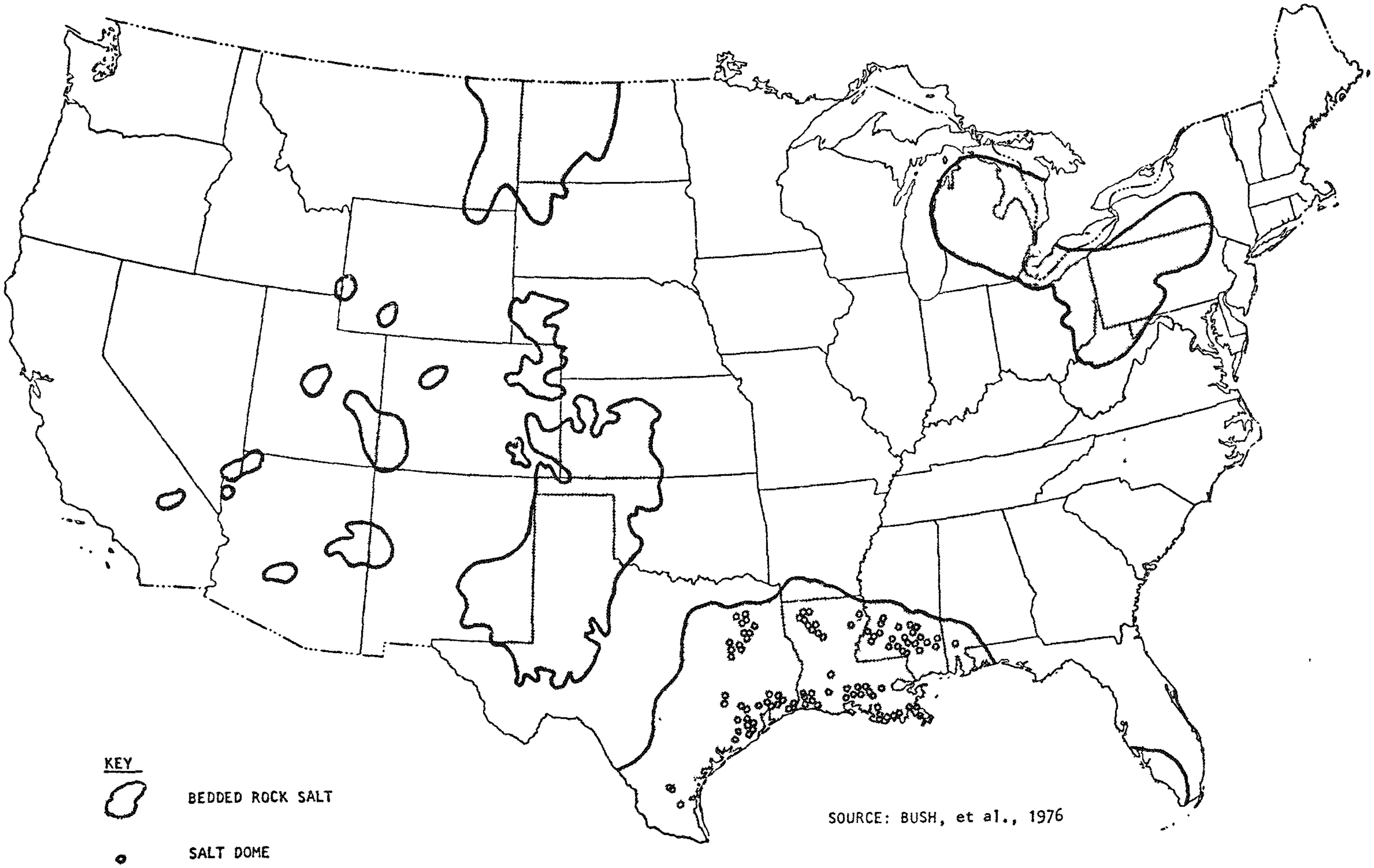


Figure 15. BEDDED ROCK SALT DEPOSITS IN THE UNITED STATED

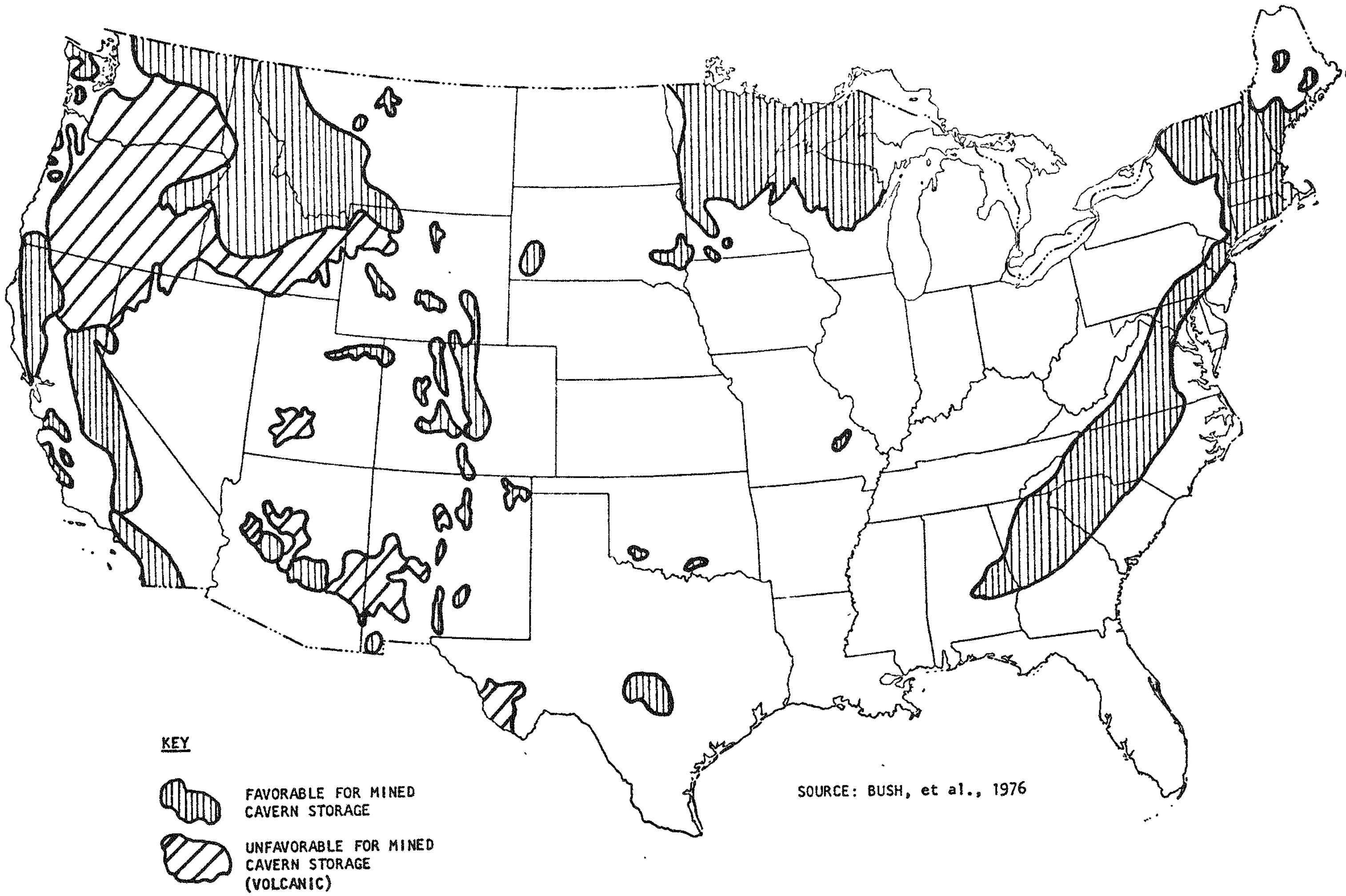


Figure 16. OUTCROPS OF IGNEOUS AND METAMORPHIC ROCK IN THE UNITED STATES

volume of base gas, because the fluctuating water volume serves to pressure the cavern and to displace the working gas.

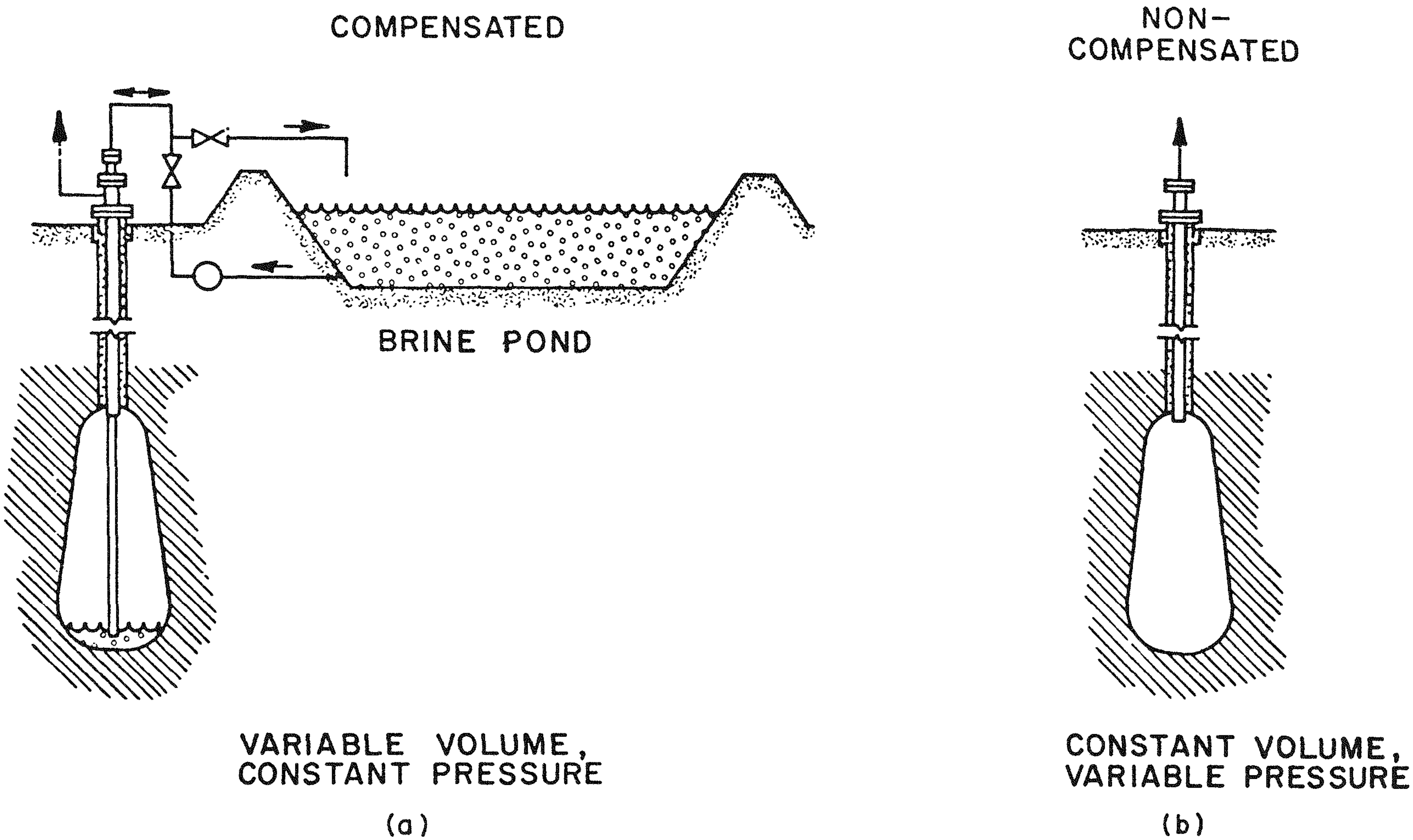
The variable-pressure cavern is a closed system in which the storage pressure is determined by the amount of gas stored in the cavern (Figure 17b). In dense, impermeable host rock, the cavern can be operated at pressures greater than hydrostatic because the withdrawal of working gas does not depend on a water displacement drive. The pressure fluctuates as the gas inventory changes. Maximum storage pressure is established by hydrostatic pressure or, in some cases, may approach lithostatic pressure. Minimum storage pressure can be determined by pipeline or compressor input pressures or, particularly in the case of solution caverns, the pressure required to prevent extreme shrinkage of storage volume by salt encroachment.

Water inflow to the cavern poses no serious problem with a water-compensated cavern and is factored into the volume of water displaced from the cavern during gas injection. The efficiency of a constant-volume cavern, however, is affected by water inflow, because the water reduces the space available for stored gas and must be pumped out of the cavern when significant quantities accumulate.

Reservoirs for compensated cavern storage do not always require surface ponds and can be designed as an underground chamber above the storage cavern (Figure 18). This design is particularly appropriate in the case of solution-mined salt caverns, in which brine rather than fresh water is used and the environmental impacts of brine on surface water supplies are of concern. Salt caverns also operate in the constant volume (or noncompensating) mode of storage. The Eminence storage caverns, operated by Transco, are examples of this method.

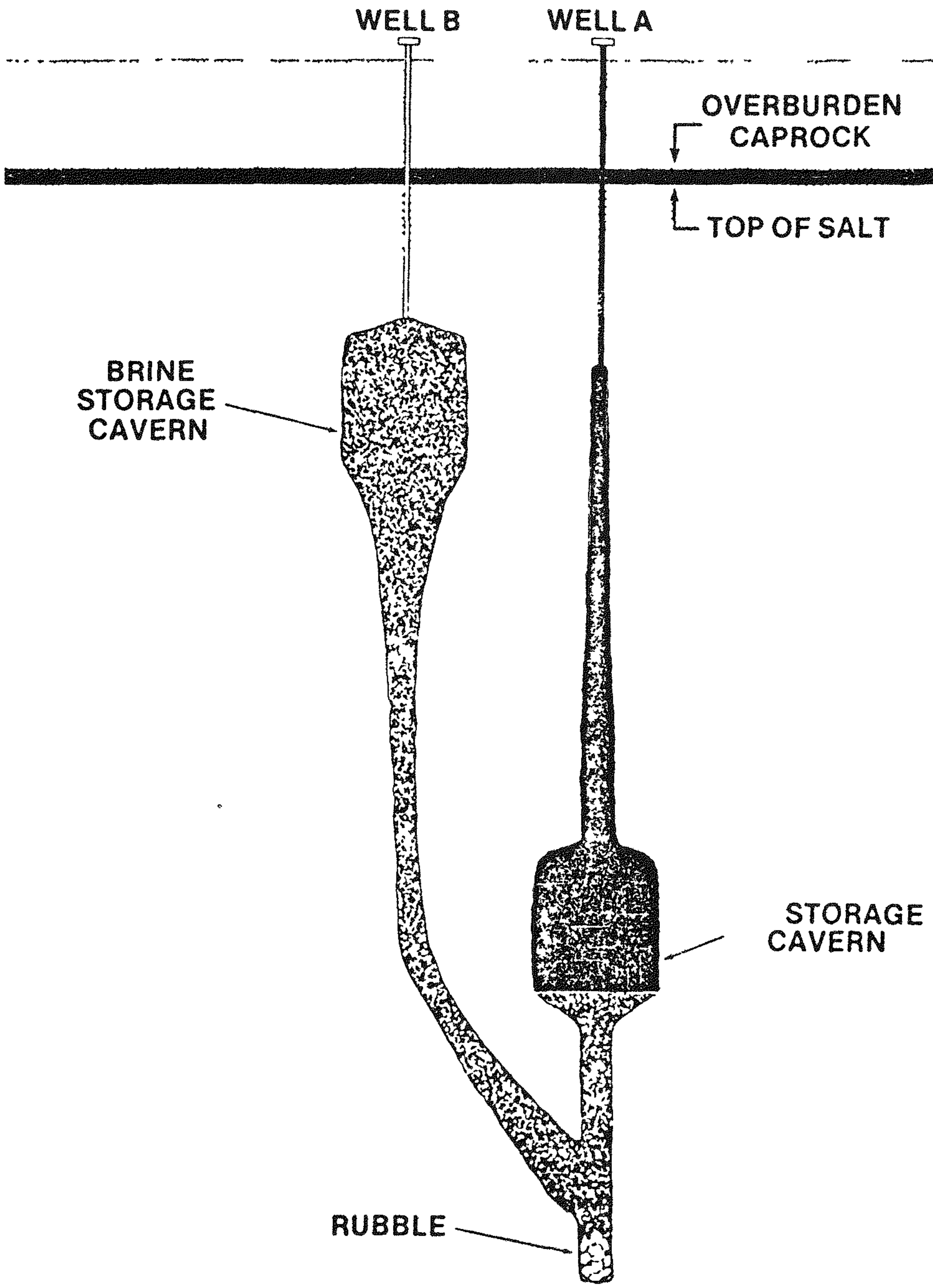
1) Solution-Mined Caverns in Salt.

Underground salt deposits occur either as "bedded" formations or as "domes." Bedded salt formations are layers that occur primarily in regional sedimentary basins, such as the Michigan Basin and Permian Basin of western Texas, Oklahoma, and eastern New Mexico, and can be as thick as several thousand feet. Subsequent tectonic forces may have folded and shifted the salt and influenced the structure and properties of the deposit. Thin layers of dolomite, anhydrite, gypsum, and potassium chloride as well as clay are frequently present as impurities, ranging from 1-2% up to 10% or more of the deposit. The presence of these impurities, many of which are insoluble or less soluble than salt, can cause difficulty in the solution-mining process, particularly in the control of the cavern's configuration.



SOURCE: VOSBURGH, et al., 1977

Figure 17. MODES OF CAVERN OPERATION



SOURCE: VOSBURGH, et al., 1977

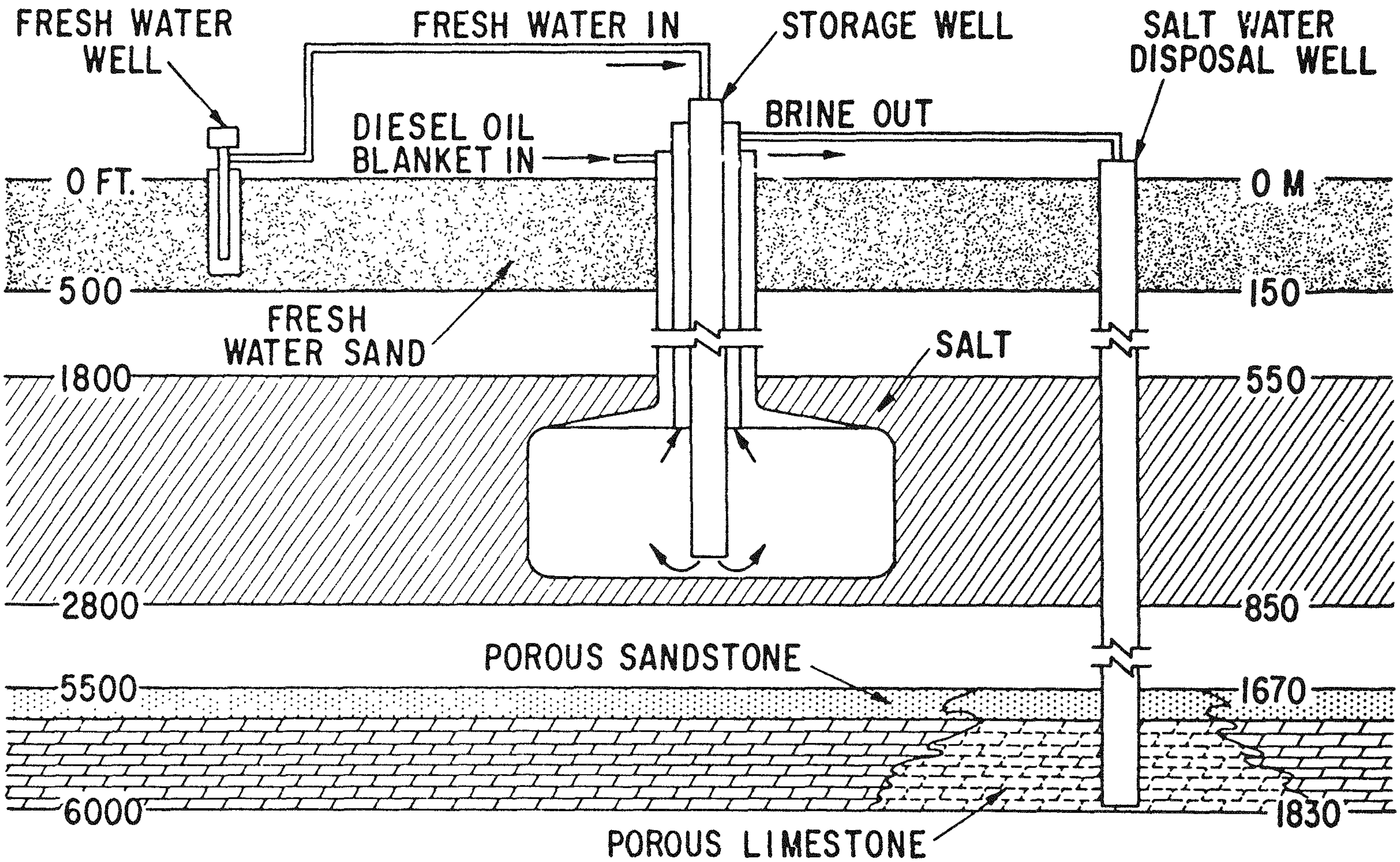
Figure 18. COMPENSATED SALT STORAGE RESERVOIR SYSTEM

Salt domes are masses extruded upward from salt layers at depths of 3,000 to 10,000 feet or greater. Oil, gas, and sulfur deposits frequently are associated with salt domes that occur as diapirs composed of 95% to 99% pure halite that have been forced upward through the surrounding sediments in a form of isostatic adjustment. This upthrust or piercement results from the rheological properties of salt that cause it to behave as a viscous liquid under high pressure and its low specific gravity (2.2 approximately) in contrast to that of the surrounding sedimentary rocks (greater than 2.4). Because the impurities that commonly occur in bedded salt layers do not exhibit similar viscous flow characteristics, they are, for the most part, retained in the deep salt beds from which the diapirs originate, in effect "refining" the salt and facilitating control of cavern configuration during solution-mining. Some blocks of impurities, particularly anhydrite, are occasionally carried along by the upwelling salt, but these are normally small and only occasionally cause difficulty. The majority of salt domes occur in the Gulf Coast states of Texas, Louisiana, Mississippi, and Alabama, although some salt zones do occur in three interior basins adjacent to the northern edge of the Gulf Coast province. These interior domes generally have shallower origins and contain a higher percentage of impurities than do the domes of the Gulf Coast.

The most common approach to solution-mining of salt is controlled leaching to create an elongated, bell-shaped chamber. Figures 19 and 20 diagrammatically show the technique for cavity development. The direct injection method involves the installation of casing and tubing into a drilled borehole and dissolving out the salt by pumping fresh or brackish water down the tubing and removing the saturated brine out the annulus. Leaching creates a bell-shaped cavern because solution occurs more rapidly near the bottom where the fresh water comes into contact with a highly concentrated brine moving upwards towards the annulus. Diesel oil is injected through the annulus to create a blanket fluid that floats on the brine and controls roof formation during leaching.

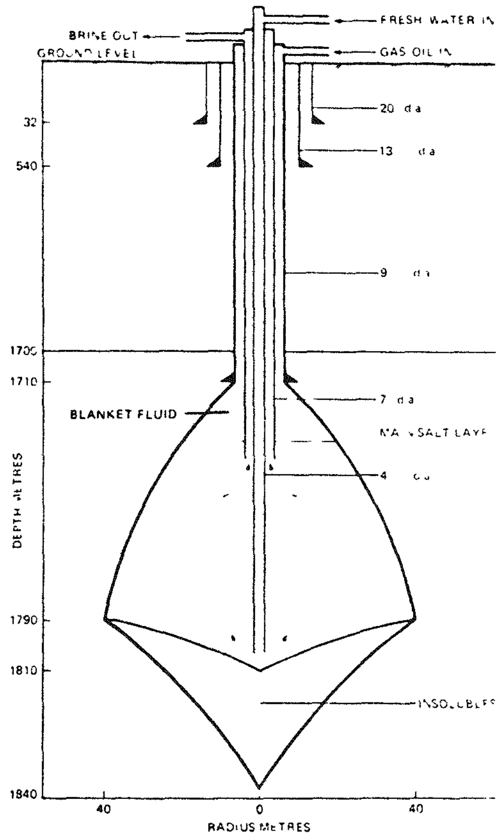
An alternative method of solution-mining is by reverse leaching where the fresh water enters through the annulus and is removed through the inner tubing (Figure 20). A greater amount of finely grained insoluble material, or rubble, is flushed out with the brine by this method and less rubble accumulates on the bottom of the cavern.

As caverns are leached from the salt, surveys are made to track the progressive development of the chamber. Figure 21 also shows the results of a sonar survey that records the configuration of the chamber during leaching over a 9-month period for the Hornsea storage caverns in England.

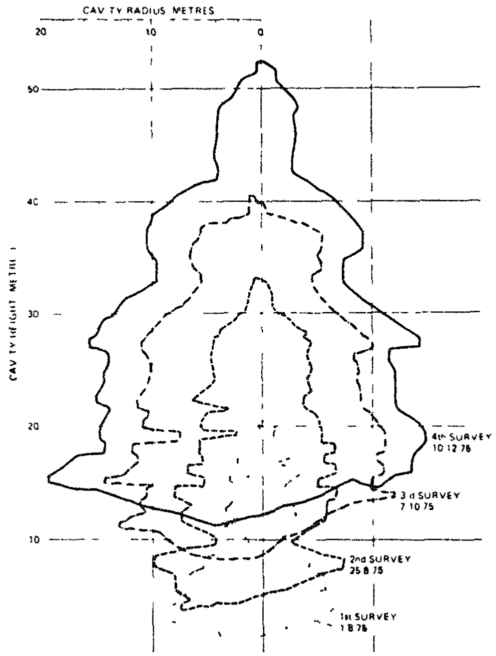


SOURCE: VOSBURGH et al., 1977

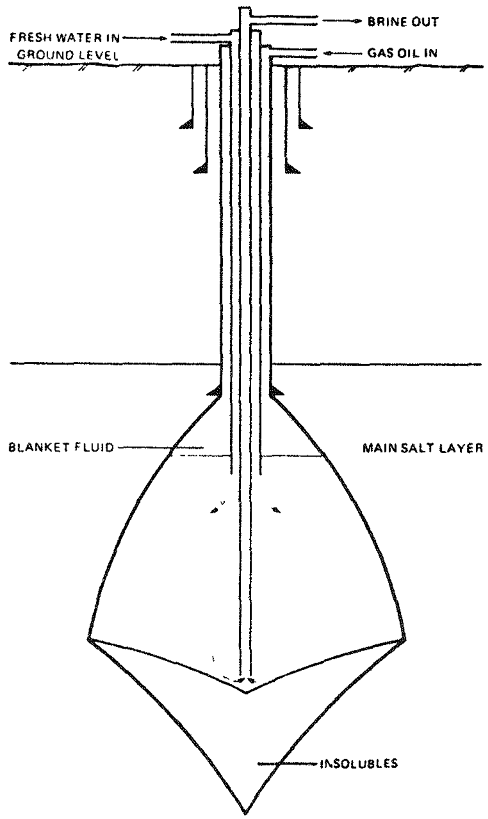
Figure 19. TYPICAL SOLUTION-MINING PROCESS



SCHEMATIC DIAGRAM OF TYPICAL LEACHING ARRANGEMENT-DIRECT METHOD



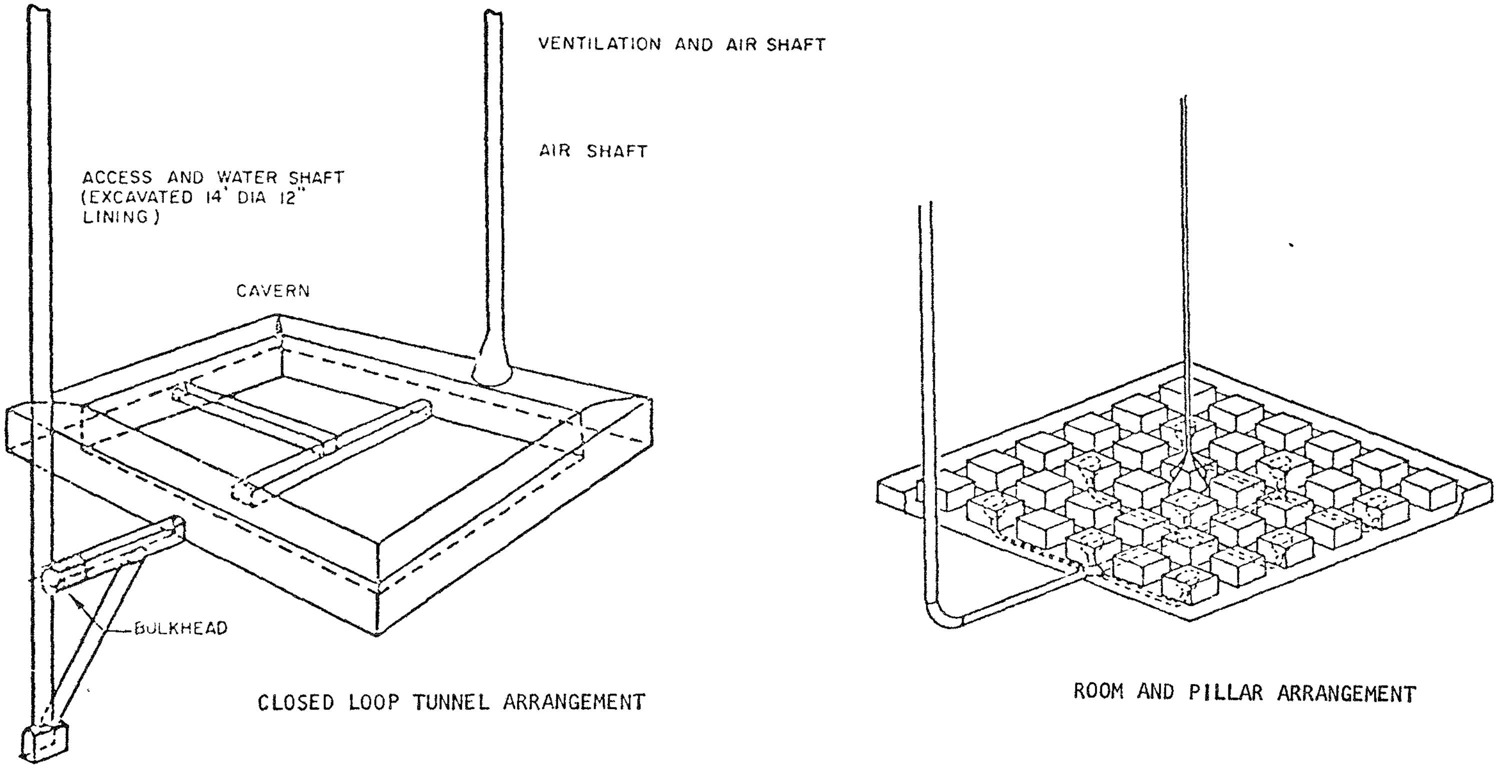
PROGRESSIVE CAVITY DEVELOPMENT- RESULTS OF SONAR SURVEY



SCHEMATIC DIAGRAM OF LEACHING ARRANGEMENT-REVERSE METHOD

SOURCE: DEAN, 1978

Figure 20. SALT CAVITY DEVELOPMENT OF SOLUTION-MINING



SOURCE: GILL & HOBSON, 1979

Figure 21. MINED CAVERN LAYOUTS

Transco's operations at Eminence have shown that cavern shrinkage due to salt flow makes it impractical to operate (maintain) salt caverns below a depth of 5500 to 6000 feet. Whether this depth limitation is generally applicable or applies only to the specific dome in which Transco's facilities are located is uncertain.

2) Excavated Caverns. Mined caverns for the storage of petroleum products have been excavated in thick shale sequences and in massive igneous and metamorphic crystalline rocks such as granite and gneiss. Limited experience in excavation of such caverns in limestone has shown that its susceptibility to solution activity along fractures, joints, and bedding planes makes it an uncertain host rock, although it may serve well in some areas. Although caverns in shale have been used for the storge of propane at shallow depths, its suitability as a host rock for deep cavern storage is less clear, because it often exhibits swelling or spalling when exposed in underground openings. This can result in roof instability and other construction problems that can lead to failure of the cavern.

Massive igneous and metamorphic rocks are generally the best lithologies for mined openings. These rock types exhibit dense, isotropic, high-strength properties that make excellent conditions for cavern construction. They are also generally more homogeneous than sedimentary rock types, resulting in a lower probability of encountering unsuitable rock and increasing the reliability of cavern design.

Limitations on the depth of mined-cavern storage are largely questions of economics. Preliminary cost estimates indicate that for a cavern capacity of 10 billion CF, a depth of 3500 to 4000 feet is optimal. Rock temperature proves to be a significant factor below this depth, because of the possibility of having to provide cooling during cavern excavation and because elevated temperature reduces the compressibility of gas and decreases the volume of stored gas. Accordingly, unusually high or unusually low geothermal gradients can significantly alter optimum depth.

A common method of cavern excavation is room-and-pillar mining, in which long drifts are excavated perpendicular to each other in a grid, creating a waffle pattern (Figure 21). This approach has been used in the mining industry for years to maximize the extraction of minerals. A configuration also used for storage caverns is the closed-loop tunnel arrangement (Figure 21). This configuration minimizes obstacles to flow and provides sufficient stability for cavern design. The choice of configuration is based on such considerations as local geology, strength and structural features of the bedrock, haulage and production rates, and volume of cavern space desired.

No deep-mined cavern specifically designed for the storage of natural gas is known. The only excavated cavern currently in use is the converted Leyden coal mine near Denver, Colo., which is operated by Colorado Public Service Company. Although very useful for limited peakshaving service, this facility operates at low pressure with relatively small storage capacity (45 million CF). Notwithstanding the fact that deep cavern storage has not previously been developed, it cannot truly be considered an undeveloped technology, because it simply combines areas of technology that are already highly developed — the excavation of underground openings and gas storage in deep caverns as pioneered by Transco.

3) Mechanisms Controlling the Containment or Loss of Gas from Cavern Storage. The same mechanisms that contain gas in porous-media storage also apply to cavern storage; however, the emphasis is changed. In porous-media storage, a major concern is the intrinsic characteristics of the lithologic confining elements, particularly their permeability and threshold pressure. In cavern storage, the site is normally selected specifically because the host rock is dense with very low intrinsic permeability and very high intrinsic threshold pressure. Purely hydrological confining mechanisms, such as the transport of gas in solution in water, are even less pertinent because the density and impermeability of the host rock minimize both the mobility of the water phase and the extent of gas contact with it. Thus in cavern storage, the major concern is the effect of any joints, fractures, or faults that may be encountered.

The permeability and threshold pressures of the host rock are not unimportant. It is simply assumed that they would be very carefully evaluated during the exploratory phase and that cavern excavation would not proceed if favorable intrinsic rock conditions were not ensured.

a) Confinement of Gas in Fractured Rock. Gas can be confined in fractured rock by either of two mechanisms, both of which depend upon the presence of water. If the fracture is closed (width less than approximately 0.01 mm), capillary water retained in the fracture can contain the gas subject to the same threshold pressure limitation as in caprocks surrounding porous-media storage. When the fracture is too wide to support a stable capillary water saturation under the prevailing hydrostatic pressure, a different mechanism comes into play.

Until recently, a tenet of propane storage design was that if the hydrostatic pressure exceeded the cavern storage pressure cavern (vapor pressure of propane), no gas loss was possible because if there were any movement of fluid within a fracture, it would be that of water flowing in rather than gas flowing out. Both practical experience and theoretical studies have shown that this is an oversimplification that is valid only under certain limited conditions. First, it must be assumed that there is adequate recharge to the fracture system, so that downward drainage of the water does not reduce the hydrostatic column. Artificial recharge of water may be required to ensure that this condition is met. This can be accomplished in some instances by simply flooding the fractures by injecting water into the soil overyling the cavern (as in Washington Gas Company's Ravensworth Propane Storage Cavern), or as proposed by Janelid,[29] a "water curtain" can be created by the injection of water in a network of closely spaced boreholes drilled horizontally or diagonally downward from galleries overlying the storage cavern.

Aberg,[1] among others, has shown that within fractures of significant width (in which capillary retention is of negligible effect), a critical downward velocity of water is required to prevent the upward escape of gas bubbles. Thus, it is not only necessary to maintain water saturation at a hydrostatic pressure in excess of the storage pressure, but also it is necessary that the entry velocity of the water into the cavern be greater than the upward velocity that a bubble would have if there were no water movement within the fracture.

Much of the literature on cavern storage presupposes relatively shallow depths. However, the storage of natural gas or hydrogen would be more economic at depths of 2500 to 4500 feet. With the greater lithostatic pressures prevailing at these depths, the probability of fractures of significant width is greatly diminished.

Much of the most recent literature on gas losses from caverns has been written in the context of compressed air energy storage (CAES). These papers refer to air loss rates of from 2% to 5%/day in "normal granite."[7,22,51] Although not clearly specified, particularly when quoted or referenced in subsequent English language publications, these papers appear to assume a) relatively shallow depth and b) operating pressures substantially in excess of hydrostatic pressure. Regardless of whether such loss rates are realistic for highly pressured caverns in "normal granite," as indicated in these publications, these loss rates are not realistic for granite caverns at less than hydrostatic pressure because a number of successful propane caverns have been excavated in granite. Propane vapor leakage, even at a very small fraction of the rates suggested in this literature, would be unacceptable under any circumstances.

Solution-mined caverns in salt are a special case; open fractures are unlikely at depth because of the creep and self-healing characteristics of salt. With the exception of minor gas losses associated with wells themselves, there is no reported loss incidence in connection with salt caverns in salt domes.

Bedded salt deposits frequently are less homogeneous than salt domes and not uncommonly contain zones of impurities that, in extreme cases, might permit gas loss, although no such losses have been reported.

b) Incidence and Magnitude of Gas Losses from Cavern Storage. Very few caverns have been developed for the containment of gases, most of these in salt. None of the salt-cavern gas storage facilities that we have studied have reported significant gas loss, nor have the solution-mined caverns used for the storage of liquid hydrocarbons reported any loss of the supernatant vapor phase. Hence, we would anticipate no loss of hydrogen if these caverns were operated under the same conditions for hydrogen.

A number of excavated caverns have been constructed, primarily either in granite or shale, for the storage of propane. Although several of these caverns have leaked, we have not been able to acquire a sufficent body of data to present quantitative conclusions on the frequency or magnitude of gas loss. As in the case of many porous-media storage facilities, the detectability of gas loss from caverns appears to vary greatly, and few, if any, caverns have incorporated a loss detection system in their initial design. Such instances of propane vapor escape as are known have first been detected at ground surface.

One case of vapor loss seems clearly attributable to the loss through drainage of the hydrostatic head in a fracture system. Another case may be due to the seepage of propane, either as a liquid or as a vapor, through permeable zones in the shale host rock. In both cases, the caverns are shallow, 400 to 500 feet, and it cannot be determined whether similar losses would have occurred with the greater lithostatic pressure of the depths appropriate to natural gas or hydrogen storage.

c) Impermeation Techniques. Methods necessary to limit the leakage of stored gas from an underground reservoir depend on the mode of storage and on the mechanism and quantity of escaping gas. In porous-media storage, in which a large volume of gas is stored under several hundred acres of land, the migration of gas from the reservoir through the overlying caprock or by lateral leakage beyond the limits of the structural closure may not be readily detected and is rarely correctible. The large volume and areal extent of such a field inhibit the application of remedial impermeation techniques to contain the leaking gas.

Cavern storage operations are more conducive to impermeation techniques. The considerably smaller volume of gas stored in an underground cavern and the restricted dimensions of the excavated opening reduce the variables associated with points of gas escape. In practice, however, identifying the nature and location of specific leakage points, primarily through hairline fractures in the wall and ceiling rock of the cavern, has been difficult. In these cases, such as Washington Gas Light Company's Ravensworth LP storage cavern and caverns in Sweden, remedial actions to prevent leakage have been applied to the entire cavern rather than to the specific points requiring impermeation measures.

A wide variety of impermeation techniques have been reported, all concerned with reducing permeability and sealing fractures within the rock. Laboratory methods have shown that a gas hydrate barrier can be "grown" in pore spaces of rock by localized convection-conduction cooling and agitation of the interstitial water as it comes in contact with a hydrate-forming gas.[20] Gases that do not form hydrates, such as hydrogen, can be contained behind a hydrate barrier created and maintained by such gases as carbon dioxide or other light hydrocarbons by injection wells located between the approaching front of stored hydrogen and the line of in-situ water. Further research would be required to determine the permanence of a hydrate barrier to hydrogen over the life of a project. Long-term chilling of a reservoir is not a proved technology, and the cost benefits of operation and maintenance are not available to determine its feasibility. The lack of field applications for the theory prevents specific recommendations for likelihood of success for the technique.

Methods of controlling gas leakage in porous rock by grouting and foams have been proposed in the literature.[20] The stabilities of foaming agents within a reservoir have yet to be determined, and further research is required to evaluate long-term effects and costs. The likelihood of completely filling the leakage channels is uncertain because of the heterogeneity of rock masses and the circuitous nature of fractures. A grout or foam treatment may be economically limiting and would appear to be most feasible in a situation in which an identified portion of a cavern requires impermeation rather than, for example, in an aquifer storage field in which the location of leakage is less discernible and the large storage area can be a disadvantage. Grout has been injected as a sealant for natural gas within the caprock overlying an aquifer, but the details and results of the remedial program are not available in the published literature. The project was unsuccessful.

In Sweden, gas and liquefied gas products are stored in unlined excavated caverns below the groundwater level; these caverns are designed to prevent leakage by the infiltration of water into the surrounding rock from a network of galleries and boreholes above the cavern (Figure 22).[1] In this manner, the hydrostatic pressure of the

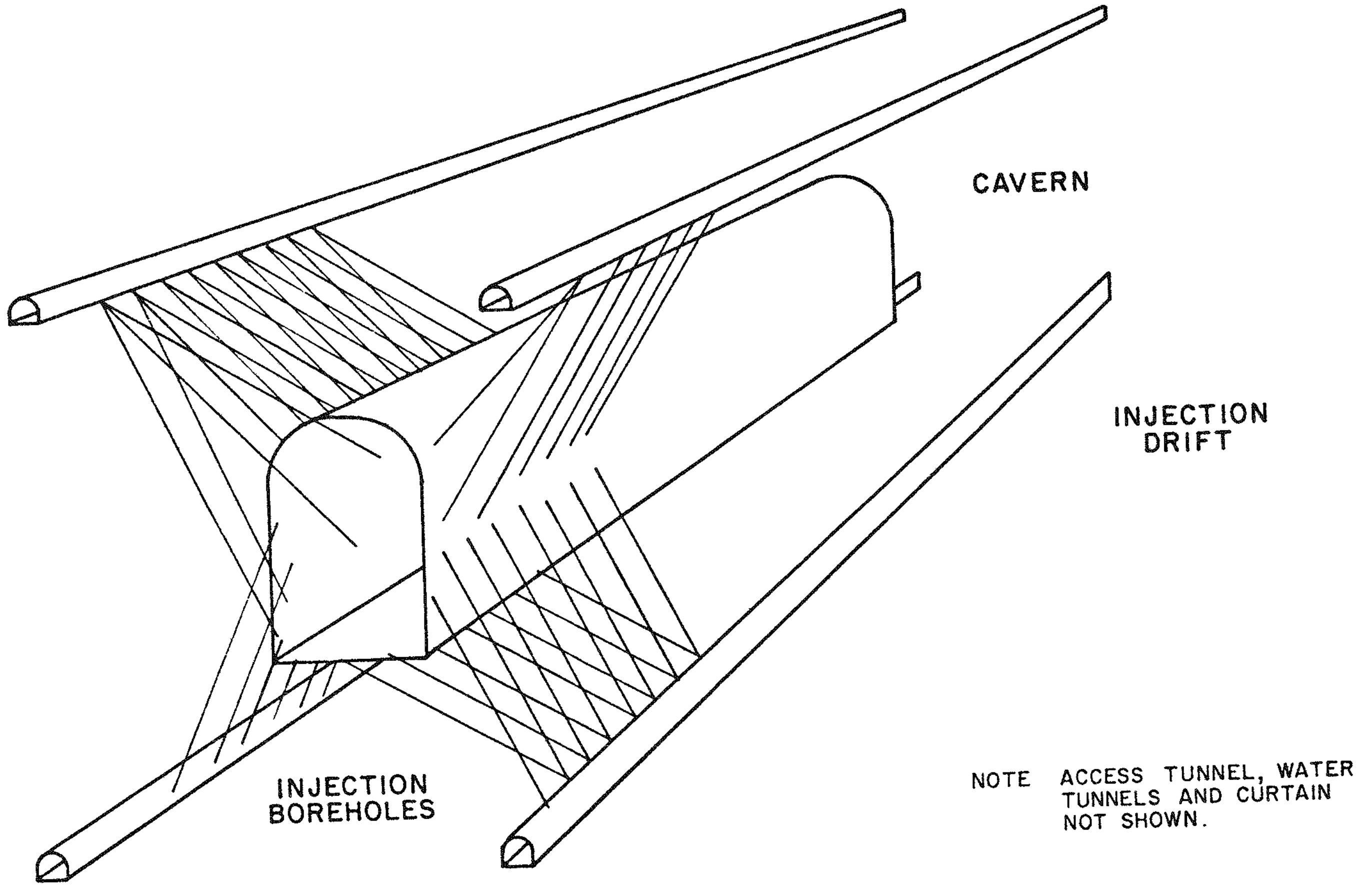


Figure 22. CAVERN DESIGN AFTER ABERG

groundwater exceeds the storage pressure of the gas and the strong downward motion towards the reservoir prevents mobile units from rising through the fractures in the rock above the cavern. Gunite, epoxy, and other materials are commonly used in construction of underground openings to seal cavern walls and ceilings from groundwater flow and could serve a similar role in sealing fractures for cavern storage of gas.

Solution salt caverns appear to have virtually no potential for leakage by fractures or by the intrinsic permeability of the salt surrounding the cavern. The viscous flow of salt under high pressure would act as a sealant mechanism for any propagating fractures. Impermeation techniques for salt caverns would most likely be grouting, particularly if leakage was associated with the shaft, the only type of gas escape anticipated at a salt cavern storage facility.

In summary, impermeation techniques, such as an infiltrating water curtain and gunite-sprayed rock walls, are demonstrable preventive measures that seal fractures in caverns and can be incorporated into an initial design as a pretreatment or anticipated requirement for a storage cavern.

Remedial measures, such as the formation of hydrates, grout, and foaming agents, may have application to both porous-media and cavern storage. In the absence of field experience, all such methods must be regarded as speculative, and further research and field testing are necessary to determine how such techniques could effectively mitigate unexpected losses during operation of a storage facility.

d) Consideration of Leakage and Its Effects

As discussed previously, some gas loss is to be expected in most modes of underground storage, particularly in porous-media storage. Such loss occurs primarily through a) solution in groundwater and b) short-term escape, usually easily remedied, through mechanical leaks associated with injection-withdrawal wells. Occasionally, natural gas is lost from the primary reservoir but recovered in an overlying porous formation and reinjected. When the rate of such losses is low or when they are promptly recognized and corrected, such gas losses are considered to be a normal part of gas storage operation and are not considered leakage. Instances have occurred, however, in which natural gas lost from the storage reservoir has reached the surface or near-surface environment in such quantities and in such locations that it constitutes an actual or potential hazard. Additional consequences of natural gas leakage, while not known to have occurred in the past, can constitute potential hazards under specific circumstances. This section considers the mechanisms by which gas can escape from a storage reservoir as potentially hazardous leakage, the consequences of such leakage, and means by which such hazards can be eliminated or ameliorated.

1) <u>Mechanisms</u>. Gas losses by diffusion into groundwater are unlikely to occur in such magnitude as to constitute a potentially hazardous leak. Accordingly, the probable sources of severe leaks will be either of a geological nature, leakage through the caprock or past the spillpoint, or of a mechanical nature, associated with the injection-withdrawal wells themselves.

Mechanical leakage associated with wells probably is most common, but because such leaks are localized and normally susceptible to direct repair, their consequences are normally less severe than those of leaks due to geological mechanisms. Most, if not all, large-scale natural gas discharges in the surface or near-surface environment resulting from mechanical leakage can be avoided and occur either as a result of inadequate routine inspection programs or human error. Most commonly, they occur either through large-scale upward migration of gas through the annulus between the casing and the surrounding rock or through leaks in the casing or tubing; they also can occur as the result of equipment failure or simple error. Leakage due to equipment failure or human error most frequently occurs during well servicing, such as when the well is not properly "killed" (filled with drilling mud or water) prior to reentry, when temporary seals installed to permit servicing are dislodged, or when tubular goods or fittings fail under high pressures applied for well stimulation.

Geological leakage usually involves the migration of gas through substantial thicknesses of overlying rock, thus limiting its volume and rate of movement and providing adequate opportunities for detection and control. For this reason, large-scale leakage due to geological factors is extremely rare.

Probably the most common source of geological leakage is defective caprock, caprock that is either intrinsically weak or is breached by faults or fractures. In some cases, a combination of geological and operational factors has contributed to leakage. Such a situation is the so-called "umbrella effect" that occurs when natural gas is rapidly injected into a reservoir whose horizontal permeability substantially exceeds its vertical permeability. A flat-bottomed "bubble"* does not form; rather, a thin laterally extensive gas layer immediately below the caprock forms that may extend beyond the spillpoint of the structure. With a slower rate of gas injection, the use of more injection wells, or controlled injection into deeper parts of the formation, the same geological conditions might provide better gas retention. The geological conditions in such a case are not unfavorable, but rather the combination of geological factors and operation methods contributes to leakage.

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* Mobile gas unit.

A similar geological-operational source of natural gas loss is the "pumping effect." If, during the injection cycle, gas is driven close to the outer limits of the reservoir and if gas is withdrawn primarily from the center of the reservoir, leaving a volume of gas near the periphery, then upon the next injection cycle, this peripheral gas may be driven further outward. After a number of injection-withdrawal cycles, the peripheral gas may be "pumped" beyond the structural closure, resulting in its loss and potential leakage to the surface or near-surface environment. Again, alternative patterns of operation can be implemented to eliminate or minimize such gas losses.

A final type of "geological" leakage needs to be mentioned, although it is rare. This is the exploration error or design error, the error in interpretation of the geological conditions, and it applies exclusively to aquifer storage in which the conditions of storage are not well known in advance. These errors are invariably the result of inadequate exploration and testing. Two examples illustrate this source of leakage. In the first, the interpretation of structural closure was based largely upon core drilling to a shallower stratigraphic horizon; however, thinning of intervening beds between this horizon and the caprock resulted in greatly decreased closure at the base of the caprock and the loss of much of the natural gas initially injected. In the second example, the reservoir was a carbonate reef rock containing both vugular and intercrystalline porosity. Field capacity was calculated on the basis of total porosity, and estimates failed to recognize that water could not be displaced from, and that gas could not move into, the fine intercrystalline porosity that constituted approximately one-half the pore space. More gas was injected than could be contained, resulting in large losses.

2) Consequences. In most instances, mechanical failure associated with wells results in gas being discharged to the atmosphere either through the well itself or in its immediate vicinity, carrying with it the danger of injury from explosion, fire, or simply the effects of high-volume, high-pressure flow. When the escaping gas is lighter than air (natural gas or hydrogen), the area of hazard is limited to the immediate vicinity of the well. When the escaping gas is heavier than air, it can spread along the ground and accumulate in low or sheltered areas, and depending upon the terrain and meteorological conditions, the area exposed to hazard may be much larger.

Potentially greater hazards occur when escaping gas does not discharge directly at the surface but rather enters shallower porous formations. Several instances have occurred in which leaking natural gas has accumulated in shallow aquifers, disrupting local water supplies by creating artesian conditions (increasing pressure so that wells flow spontaneously and/or new springs develop), by creating gas pockets that cause pumps to lose their prime, and by creating fire and explosion hazards when gas is coproduced with water. When the gas escapes into a partially confined aquifer, it can migrate over considerable distances.

If leaking natural gas accumulates under high pressure in a confined shallow porous formation, the potential for blowout and cratering exists. Consider a confined sandstone at a depth of a few hundred feet overlying a storage reservoir at several thousand feet. If gas accumulates in the shallow reservoir, its pressure will rise towards the storage pressure and eventually exceed the lithostatic pressure of the shallower formation. At some point above the lithostatic pressure, the overlying rock can rupture and, under some circumstances, eject large volumes of soil and rock. Even when the discharge is less violent, there also can be surface disruption due to "cratering." When large volumes of gas move at high rates through soft or poorly consolidated materials, some of this material can be carried and ejected by the gas stream, resulting in an undermining of the ground surface in the vicinity of the discharge. Where the overlying material is permeable and unconsolidated, it also can be fluidized by the high-velocity gas flow. Whether through undermining or fluidizing, the ground surface loses its strength and subsides, often leaving a pronounced depression or crater.

Geological leakage also can result in the introduction of gas into shallow porous formations with the same potential for disruption of water supply or blowouts and cratering. However, because geological leakage usually involves the migration of gas through substantial thicknesses of overlying rock, the rates of gas accumulation in shallow formations can be expected to be lower than those arising from mechanical leakage; accordingly, the dangers of excessive overpressuring are greatly reduced.

3) Incidence. Geological leakage, apparently associated with caprock defects, has resulted in abandonment of a few aquifer storage fields, but in others, notably Herscher, the leakage has been brought under control and the field operated satisfactorily. Leakage through geological mechanisms is suspected or alleged in several other fields, but resolution of such questions is beyond the scope of this study. An example of the kind of question that is not susceptible to immediate resolution is whether gas occurring in a shallow aquifer has originated from an underlying storage reservoir or is native biogenic gas. There does appear to be a higher incidence of leakage, particularly that due to geological mechanisms, in aquifer storage than in depleted field storage.

Depleted reservoirs are assumed to be necessarily free from leaks due to geological factors because their integrity is proved by their containment of hydrocarbons throughout long periods of geologic time. For this reason, the monitoring of possible natural gas leaks in depleted fields frequently is less intensive than it is in aquifer fields.

Also, the detection and quantification of leaks from depleted fields are further complicated by the effects of past and present oil and gas production from underlying or overlying reservoirs. When a region is known to contain gas naturally, the significance of the discovery of small quantities of gas is ambiguous.

Although most natural gas leaks from depleted-field storage are attributed to mechanical factors, a number of operators and investigators suspect that leakage due to geological factors also occurs. In some cases, operational procedures contribute to the suspected leakage, but other instances seem best explained by deterioration of caprock integrity. However, no case of purely geological leakage from depleted reservoirs has been fully documented.

Determination of the incidence of leaks due to mechanical causes in depleted-field storage is difficult and complicated by the frequently difficult distinction between leakage resulting from storage operations and that resulting from pre-existing oil or gas production operations. Also, great differences exist in the levels of effort that the many operating companies employ to prevent mechanical leaks.

In general, the incidence of release of significant gas volumes in the surface and near-surface environment resulting from mechanical causes apparently is similar to, or slightly greater than that experienced in the aquifer storage fields, but leaks arising from geological causes are less frequent.

Leakage data from cavern storage are sparse. Experience with cavern storage of natural gas is limited to solution caverns in Michigan, Mississippi, and Texas and a converted coal mine, the Leyden Mine, near Denver, Colo. No serious leakage problems are reported from these facilities. We also have investigated leakage data from LP gas storage caverns, particularly those formed by excavation. At least two LP caverns have leaked through fractures in the overlying rock. However, LP caverns are customarily excavated at depths of only 400 to 500 feet. Thus, small quantities of gas can approach the lower levels of the biosphere with relative ease. With the greater thickness of overlying sediments and higher hydrostatic pressures prevailing at greater depth, fracture leakage from deep cavern storage probably would be minimal. Minor, easily remedied leaks of a mechancal nature associated with shafts also have been reported but are infrequent. In general, the incidence of leakage from caverns is significantly less than that from porous-media storage.

In our study of leakage, we have attempted to identify correlations between the incidence of leakage and other factors such as regional geological conditions, operating methods, etc. Within the limited data available, no such correlations have been identified other than the unsurprising suggestion that the security of gas storage is in direct proportion to the experience and technological investment of the operators.

4) Detection and Remedy. The primary emphasis should be upon detection of gas losses before they become serious leaks. However, leak control begins with the exploration and development phases. All underground storage facilities are sited with the expectation that the geological conditions are favorable for the containment of gas. On the other hand, there is a considerable variation in the quantity and quality of data upon which such an expectation is based. Particularly in connection with aquifer storage, the possibility of geological leaks would seem to provide a strong incentive for thorough efforts to define and characterize the structure and to establish the limits and competency of the caprock. In addition, the selection of storage sites must include consideration of means for the early detection and remedy of gas losses. The presence of overlying secondary reservoirs and secondary caprocks suitable for observation and/or the gathering of gas for reinjection is a very important factor.

Assuming that the storage site has been thoroughly defined and tested, the means for leak detection consist primarily of 1) observation wells to detect gas movement beyond the reservoir either directly or by pressure response, 2) observation and testing of wells and shafts, and 3) periodic inventory evaluation, preferably by reservoir tests involving periods of shut-in with well shut-in pressures applied to a material balance model.

Observation wells if necessary should be completed in the storage formation itself at intervals around the periphery of the reservoir, particularly up-dip, and in porous and permeable zones above the reservoir. The number, location, and spacing of observation wells are determined by local geological conditions, as are the method and frequency of observation. Continuous water-level recorders should be installed in at least some of the observation wells completed in overlying permeable zones.

A large number of methods are available for monitoring the condition of wells and for detecting and localizing leaks in them. Some common techniques are listed below.

a) Methods of Monitoring.

- Monitor the Annulus Pressures Between the Injection String and the Next Outer String. For a well completed with tubing on-packer arrangement, the annular pressure response of the tubing-long string annulus is monitored.
- Monitor the Annulus of the Intermediate and/or Surface Strings. Where the well is completed without having the entire annulus on the outside of the production string filled with nonpermeable materials and where there are no native hydrocarbons existing above the injection reservoir, the annulus between the flow and the

intermediate and/or surface string is monitored. Fluids not confined to the injection reservoir can be emitted through the annulus. Surveillance of the annulus would indicate if and when such has occurred.

- Radioactive Tracer Survey. Conduct a base log to record existing radioactivity in the formation, and then inject a radioactive material with the fluid stream. Tracer logs then are conducted to determine the location of the radioactive material that, in turn, indicates whether the injected fluids are confined to the injection zone.

- Casing Inspection Log. An electrical survey is conducted that averages the casing wall thickness at any one circumference, and an interpretation of the percentage of metal existing at that circumference indicates the integrity of the casing at that point.

- Pressure Test on Casing with Gas. A packer or a similar type of shut-off tool is set above the injection zone to isolate the casing to be tested. Pressure equal to the reservoir operating pressure is applied to the casing, and the pressure response is monitored at the surface.

- Pressure Test on Casing with Liquids. A packer or a similar type of shut-off tool is set above the injection zone to isolate the casing to be tested. The casing is filled with liquids; surface pressure is applied; and the pressure response is monitored at the surface. Extreme caution should be exercised in utilizing this method because the weight of the column of liquids itself is a pressure factor.

- Neutron Logs. Neutron logs are conducted at different periods during the life of the well to compare the existence and/or accumulation of hydrocarbons behind the casing from one time to another.

- Sonic Detection. A sonic detection tool is operated, and the detection of concentrated noise at any point indicates fluid movement.

- Cement Bond Log. The cement bond log is a tool that assists in the evaluation of the cement bond to both the formation and/or casing. The tool is particularly valuable in locating the top of the cement behind the casing.

- Temperature Log. A temperature survey is conducted, and a change from the normal temperature gradient of a previous temperature survey indicates fluid movement through or behind the casing.

- Spinner Survey. To locate a hole in the casing, a packer or a similar type of shut-off tool is set above the injection zone to isolate the casing to be tested. A spinner tool then is inserted through a lubricator in dry casing; any gas movement causes the spinner (on the wire line tool) to rotate.

- Pump and Plug Test. To locate a hole in the casing, a packer or a similar type of shut-off tool is set above the injection zone to isolate the casing to be tested. The casing is filled with liquids; a movable top plug is installed at the surface; and pressure is applied with liquids. When the top plug passes the hole, the plug stops its travel. The location of the casing hole is measured by a surface indicator. If no hole exists, there is no top plug movement.

- Camera Inspection. A television monitor or a downhole camera can be inserted inside the casing. The camera must be run through a lubricator in dry casing; its use is limited by allowable pressures induced upon the camera.

Periodic reservoir tests can detect large gas losses through the recognition of losses in inventory; fundamentally, they are an application of Boyle's Law. Assuming that the effective volume of the reservoir at a given level of inventory is known, there should be an equivalent equilibrium pressure. This pressure is determined by shutting in the field for a time and observing the equilibrium pressures in selected wells. The accuracy of this method depends upon 1) the accuracy of the reservoir model, 2) the number and distribution of wells observed, and 3) the length of the shut-in period. In general, this method does not work well in the early stages of field development (the first three or four injection-withdrawal cycles) because the storage volume is not well stabilized nor is the reservoir accurately modeled. Once the field has been stabilized and the model refined, this material balance approach can detect gas losses if carefully performed. Inappropriate well selection and/or brief shut-in periods can seriously degrade the accuracy of these tests.

b) Remedial Measures. In porous-media storage in which leakage results from and is closely associated with the wells themselves, the well-developed technology for remedial work is as varied as the potential sources of leakage themselves. Methods range from simply tightening a fitting to killing, cementing, and abandoning the well entirely. When casing or tubing fails, it can either be replaced (if not cemented in place) or be sealed and reinforced by inserting a "liner," another piece of casing of slightly smaller diameter. When the leak is associated with the cement between the casing and the borehole, selected intervals can be perforated and cement or chemical grouts injected to reestablish the seal. For other types of leaks, a large selection of plugs, packers, and chemical sealants exists, each suited to specific purposes.

When the leak arises from geological causes, little can be done to directly remedy it, other than reducing storage pressure. In such a case, the main emphasis must be to bring the leaking gas under control and either vent it under safe conditions or recycle it. In the case of geological leaks and mechanical leaks that result in subsurface gas accumulations outside the immediate vicinity of the well itself, the first concern must be venting to isolate the point of surface gas occurrence and to prevent or relieve pressurization of shallow horizons.

In the case of cavern storage, mechanical leaks can often be treated by variations of the same techniques employed in porous-media storage. If leakage does occur through joints and fractures, it may be susceptible to control by increasing the differential of hydrostatic pressure over storage vapor pressure either by reducing the storage pressure or by artificially augmenting the hydrostatic head. Fracture leakage, when its location is well understood, can be reduced or eliminated by high-pressure grouting through wells drilled from the surface, although the specific location of leaking joints rarely is sufficiently well known to make this approach feasible.

5) Conclusions. Because the escape of gas from undergound storage to the surface or near-surface environment does occur, however infrequently, it must be a factor in storage facility location and design. On the other hand, most leaks in both cavern and porous-media storage are associated with the mechanical elements of the wells or shafts and are normally susceptible to early detection and repair. Geological leakage has occurred in aquifer storage and, to a lesser degree, in shallow cavern storage. Geological leakage in depleted-field storage is suspected in some instances but has not been conclusively proved.

In all forms of storage, careful site selection and testing, regular monitoring, and periodic well inspections are essential.

e. Mixing of Dissimilar Gases in Underground Reservoirs

When hydrogen gas is stored in an underground reservoir, the possibility of mixing with an inert base gas or natural gas that may have previously existed in the reservoir must be considered.

Mixing of two different gases in an underground reservoir cannot be avoided. Whether this mixing should be encouraged or discouraged depends on the use of the stored gas. For the case of hydrogen gas storage, there are two possibilities. The first is that hydrogen will be used or a supplement to natural gas during those periods when demand is high and natural gas supplies are low. The economic analysis in this study shows the substantial influence of base gas costs on the ultimate cost of service. If this base gas can be cheaper than hydrogen, the cost of service drops significantly. The second possibility is that hydrogen will be used as a chemical feedstock; therefore high-purity requirements determine the amount of mixing that can be tolerated.

Fortunately there have been several experiences with storing dissimilar gases in porous underground reservoirs. We review them here and relate the results of these experiences to the storage of hydrogen. The use of cheaper dissimilar base gas in cavern storage is a simple extension of the use in porous reservoirs. This latter expediency has not been followed because historically natural gas has been priced low enough.

The two cases discussed here are the experience of Gaz de France,[17,39] which operates the Beynes Field for the storage of natural gas, and of the U.S. Geological Survey,[19,58] which operates Bush Dome near Amarillo, Tex., for the storage of helium.

1) Beynes Field. Since 1956 the Beynes gas reservoir had been used for the storage of manufactured gas (sometimes called "city" gas or "town" gas); in about 1970, a decision was made to convert the field to the storage of natural gas. At times, the manufactured gas consisted 50% to 60% hydrogen gas. A decrease in the local demand for low-Btu gas plus an increase in the supply of natural gas were the reasons for the conversion.

The Beynes Field is an aquifer with a capacity of 500 million cu m (18 billion CF), of which 360 million cu m (13 billion CF) is working gas. The storage interval is a 10-m (30-ft) thick unconsolidated sandstone with a permeability of 3 to 5 darcies. This interval is at a depth of about 1200 ft.

In the conversion program, the reservoir was first filled with manufactured gas (300 million cu m). Half the working gas (100 million cu m) was removed from the center of the field, and then natural gas was injected at the south end of the field with simultaneous withdrawal of gas from the north. After 80% of the gas had been exchanged, the winter season approached, and the field had to be used for normal withdrawal. A total of 40 million cu m of natural gas (NG) was removed from the injection point with no mixing of manufactured gas.

Subsequently, 200 million cu m of natural gas was injected, and 100 million cu m of gas was removed in the second winter. Only 14% of the withdrawn gas was of low calorific value. In four subsequent winters, 100 million cu m was removed, with less than 1% of the original manufactured gas coming out. The data for the field are now as follows:

Useful Capacity	160 million cu m
Base Gas – Natural	70 million cu m
Manufactured	108 million cu m

A mathematical model was developed to predict the composition of the gas withdrawn at the removal wells as the "old" gas was swept toward one end of the reservoir by the injection of natural gas at the other end. The pattern of withdrawal followed the simple model fairly well, but this was a very porous and permeable interval with a fairly homogeneous composition. Some mixing of the gases was observed, but this was not a problem because markets were available in the gas distribution system for gas with different heating values.

The conversion of the field did not follow the original plan because of interruptions in the supply of natural gas and the higher demand for fuel one winter because of much colder temperatures. However, once the conversion was completed and the reservoir used in a "normal" manner, less than 1% of the gas withdrawn consisted of the original "manufactured gas." About 40% of the base gas in the reservoir is the original "manufactured" gas.

This operation has been so successful that Gaz de France is currently using an inert base gas (carbon dioxide-nitrogen) as the base gas in new reservoirs as well as old reservoirs and as the gas to test the integrity of the reservoir and aboveground facilities.[19]

Depending on the particular reservoir, the carbon dioxide makes up 20% to 63% of the cushion gas and permits withdrawal of 50% to 33% of total capacity. The carbon dioxide for this use is by-product compresser exhaust produced by burning natural gas in specially designed heat engines and passing the exhaust through dehydration units to remove the water and through catalyst beds to remove the oxides of nitrogen.

2) Bush Dome. The Bush Dome reservoir has had a very different history from that of Beynes Field. Bush Dome was discovered in 1924 and developed to supply helium-bearing natural gas for processing at a helium plant nearby. The gas was produced from the Brown dolomite formation at about 3300 ft. This formation is rather heterogeneous, containing anhydrite, shale, and sandstone stringers. Its porosity varies from 4% to 20%, and its permeability is about 10 millidarcies. The gas-filled pore volume is 5.6 billion CF.

Pure helium was injected into this reservoir from 1945 to 1959. This helium represented amounts in excess of market demand. In 1959, 80% of this injected helium was withdrawn.

In 1960, the U.S. Department of Interior began to develop the reservoir for permanent helium storage. Projections showed that the rate of consumption of helium would deplete all known sources within 30 years unless conservation measures were taken. Pure helium and raw helium (gas containing about 70% helium, 30% nitrogen) were injected into the middle of the reservoir. Excess gas was removed from wells at the perimeter of the reservoir to maintain reservoir pressure below 817 psi (the discovery pressure). By 1977, 69 trillion CF raw helium had been injected.

A mathematical model was developed to predict the appearance of the injected helium at the removal wells. The model accounted for pressure, temperature, rate of injection, compressibility, porosity, permeability, and density of the gases. Although the model predicted the pattern of the helium "cloud" fairly well, the recovery wells were invaded by the helium ahead of the computed times. In fact, the distances traveled by the helium were two to four times the computed distances for the same time.

Four explanations have been offered for early invasion of the recovery wells:

- Gravity segregation, which can produce helium velocities at the leading edge that are double the injection velocities
- Porosity anisotropies
- Diffusivity of the helium at the leading edge
- High permeability "fingers."

Which, if any, of these explanations is responsible for the behavior of the gas migration is speculative, and further refinement of the model and more data from the reservoir are required.

3) Conclusions. The experiences of Beynes Field and Bush Dome can lead us to the following conclusions with respect to mixing of gases in a porous storage reservoir.

If mixing is undesirable, it can be reasonably well controlled in homogeneous reservoirs of high permeability and porosity. On the other hand, existing mathematical models are not sophisticated enough to represent reservoirs that have a heterogeneous structure and low permeability. This shortcoming of the models can be overcome by very careful, slow injection of the gases, as well as by monitoring of the gases in the reservoir by observation wells. The latter solution can be very expensive if many wells are required.

B. Detailed Technical Evaluation of Hydrogen Properties

1. Safety Aspects of Handling Hydrogen Gas

This section discusses safety issues in underground hydrogen storage, except for those arising from hydrogen embrittlement of metallic components, which are discussed in Section II-B-3. This section is concerned primarily with the changes that would have to be made when an underground natural gas storage facility is converted to hydrogen storage.

Gas storage is regulated by the Code of Federal Regulation,[62] which applies to hydrogen as well as to natural gas. Only one significant change will have to be made when a natural gas facility is converted to hydrogen: conformation to the National Electrical Code,[42] an otherwise nonmandatory but industrially accepted standard, which will make it necessary for most electrical equipment in the facility to be replaced. A few other very minor changes may be necessary, but there appear to be no other codes or regulations that would require a hydrogen storage facility to be treated any differently from a natural gas facility.[41]

Hord[27] has examined and compared the safety aspects of hydrogen with those of methane (and gasoline). Pertinent safety-related properties of hydrogen and methane from Hord's paper are summarized in Appendix B.

No change will be required in the structural design of compressor stations. These buildings usually are designed to withstand minor explosions inside; for example, windows can be hinged so they can fly open to relieve internal overpressure. Sufficient ventilation is required by the Code of Federal Regulations to prevent an accumulation of gas that will endanger employees; ventilation capable of maintaining a methane concentration below the flammability limit of 5.3% should keep the concentration of hydrogen below its flammability limit of 4.0%, though this would of course depend on the size of a leak. Compressor station buildings are already required to be made of noncombustible materials. Though the theoretical energy of explosion (on a volumetric basis) of hydrogen is less than that of methane, hydrogen has a much lower energy of ignition than methane (0.02 mJ versus 0.29 mJ for methane) and is more readily detonated.[27] In spite of this, the chances of a building or its contents surviving an actual explosion depend more on the conditions of the explosion (such as gas concentration, ignition source, degree of confinement, and the geometry of the enclosure) than on the type of gas.

The National Electrical Code defines Class 1 hazardous locations as those "in which flammable gases or vapors are or may be present in the air in quantities sufficient to produce explosive or ignitible mixtures,"[42] including locations in which the hazardous gases "will normally be confined within closed containers or closed systems from which they can escape only in case of accidental rupture or breakdown of such containers or systems."

Thus, electrical equipment and wiring installed in either a natural gas or a hydrogen compressor station must conform to Class 1 standards. However, whereas natural gas is a Group D hazardous chemical, hydrogen is a Group B chemical, requiring more heavily built and more tightly sealed electrical equipment than Group D chemicals. Therefore, virtually all electrical equipment and wiring in a natural gas storage facility, including the cathodic protection systems, will have to be replaced with equipment conforming to Group B standards when the facility is converted to hydrogen storage.

Natural gas leak detectors probably can be retained for use in a hydrogen compressor station, though recalibration may be necessary. The sensing element in detectors, most commonly a hot wire, is itself a potential hazard. However, a detector suitable for use with methane should be acceptable for use with hydrogen, because the autoignition temperature of hydrogen (the minimum temperature at which a combustible mixture of fuel and air can be ignited by a hot surface) is higher than that of methane. The sensing element is enclosed by a flame arrestor. This is a screen or metal frit with holes smaller than the maximum experimental safe gap (MESG), which is the maximum permissible clearance between flanges (or sides of a hole) to ensure that an explosion does not propagate from within an enclosure to a flammable mixture surrounding the enclosure. The MESG for hydrogen is 1/15 that for methane, so a flame arrestor designed for methane service may not be suitable in a hydrogen atmosphere. Alternatively, commercially available hydrogen detectors may have to be installed.

Because hydrogen has a much lower ignition energy than methane, the use of conductive paint and other protective coatings on floors and equipment is imperative. Special attention must be given to eliminating all possible sources of static electricity. However, because even a weak spark due to the discharge of static electricity from a human body may be sufficient to ignite either hydrogen or methane,[27] personnel may be required to wear antistatic clothing to make a converted storage facility more safe in this respect.

The dehydration system in a natural gas storage facility generally consists of methanol injection at the wellhead followed by dehydration with glycol or dry dessicant. The methanol prevents the formation of solid hydrates of methane, which can plug the wellhead or gathering lines. Hydrogen is not known to form hydrates. Furthermore, unlike methane, hydrogen has a negative Joule-Thomspon coefficent (above $-95^{o}F$), so the temperature of hydrogen increases slightly (a few degrees Fahrenheit at most) when it expands isenthalpically, as when flowing out of a well. Thus, moisture will not condense or freeze inside the well or gathering lines. In a storage field where only hydrogen is present, the methanol injection system therefore could be eliminated. However, in a field where methane was once stored, some methane will always be present in the withdrawn gas, so as a precaution, wellhead methanol injection should be retained.

Glycol dehydration towers should be completely compatible with hydrogen, although greater capacity may be needed if the volume of gas cycled is greater.

Pressure-relief devices commonly used for natural gas include rupture discs (generally used only on compressor equipment) and various types of relief values. In transmission pipelines, a blowdown valve is opened in emergencies, which immediately empties a section of pipeline of gas down to atmospheric pressure. All such devices should be safely applicable to hydrogen service, if their materials of construction are not susceptible to hydrogen embrittlement.

Gasket materials and seals now in use with methane probably can be safely used with hydrogen, although this is open to debate. Research is currently under way (for example, at Sandia Laboratories) to provide more definitive answers to this problem.

Building and component layout and spacing within a natural gas storage facility can remain unchanged when converted to hydrogen storage. Buildings are spaced so that a large open leak in one will be unlikely to create an immediate fire hazard in an adjacent building. The likelihood of a fire spreading depends upon the rate at which the fuel vapors mix with air, which in turn is affected by the diffusion velocities and bouyant velocities of the fuels. Both properties have higher values for hydrogen than for methane, so a fire hazard should exist more readily with hydrogen than with methane. However, because hydrogen has a higher bouyant velocity than methane, a fire hazard will not persist for as long as with methane, and a hydrogen fire will have a greater tendency than a methane fire to burn upward rather than outward, thus reducing the danger of spreading. In addition, a hydrogen flame generally radiates a lower percentage of its thermal energy to the surroundings than does a methane flame. This further reduces the chance of a fire spreading. Therefore we would expect that the existing layout of a natural gas storage facility can be used safely with hydrogen.

If an energy flow rate of hydrogen equivalent to that of methane is desired, the volumetric flow rate of hydrogen will be about three times that of methane. Some devices, such as meters, may not be capable of safely handling the higher flow rate. Each piece of equipment at a storage facility will have to be checked to ensure that a higher flow rate will not cause potentially hazardous mechanical failures.

To safely operate an underground hydrogen storage facility that has been converted from natural gas storage, only a few relatively minor changes will be necessary. Most electrical equipment and wiring will have to be replaced. Leak detectors will have to be checked for compatibility with hydrogen and possibly be recalibrated and fitted with proper flame arrestors. Mechanical equipment will have to be checked to determine whether it can accommodate higher gas flow rates. In addition, some operating procedures will have to be adjusted. With the exception of rewiring, all the items listed above are not expected to have a large impact on the cost of service, and no major technical gaps have been identified.

2. Environmental Effects of Hydrogen Use

The underground storage of hydrogen gas does not appear to pose any significant adverse impacts on the terrestrial or aquatic ecosystems in the vicinity of storage facilities. There are two ways that hydrogen could escape from the storage horizon and possibly reach the surface. First, gradual seepage from a storage reservoir could occur through overlying rock layers because of geological mechanisms, as discussed in Section II-A-2. Second, rapid leakage at damaged wellheads can occur because of mechanical leaks that usually are short term and promptly corrected.

Free hydrogen exists in the atmosphere in very minute amounts. It is the lightest of elements and consequently very buoyant, which would lead to its rapid dispersal upon entering the atmosphere. Free hydrogen is not known to be toxic to living organisms[11]; consequently, the likelihood of significant adverse impacts arising from the release of hydrogen into the surface environments is very small.

The preparation of an environmental impact statement for an underground hydrogen storage facility would follow the format of impact statements currently being required for the testing, construction, and operation of underground natural gas storage facilities. The greatest potential for environment impacts may occur during the construction of these facilities because of such activities as the drilling of wells, ditching for the installation of pipelines, and building or upgrading of access roads. The temporary disruption of farming, drainage tile lines, wildlife habitats, and vegetation caused by rights-of-way clearing, temporary removal of fence sections, and movement of construction equipment can be minimized by planning. Conversion to hydrogen storage at an existing natural gas storage field would further minimize these temporary effects.

Impacts on historical, cultural and archaeological landmarks, reported threatened and/or endangered species, and recreational and wildlife areas are site-specific and would have to be evaluated, in addition to other factors, during the environmental impact analysis at a selected location.

Theoretically, imperceptible seepage by molecules of a gas from a storage reservoir over a prolonged time is possible through the confining rock layers as well as fractures and in joints. Such gradual diffusion could reach the surface in undetectable volumes at atmospheric pressure. Significant leakage of large volumes of gas due to geological mechanisms, as discussed in Section II-A-2-d, is rare. In one reported case, the leakage of detectable quantities of methane from underground storage facilities caused localized minor crop and vegetation damage.[32] It is not clear whether this vegetation damage resulted directly from the presence of methane or indirectly from associated constituents, odorants, for example, of displacement of oxygen and/or water; by itself methane is not toxic to natural life. The nontoxicity of hydrogen precludes such damage in the rare event that large volumes would gradually escape through geological mechanisms.

Hydrogen could escape rapidly from the storage area as a result of a damaged wellhead; however, damage to wellheads can be repaired and avoided. A rapid release of hydrogen from an injection-withdrawal well could create a noise problem that can be minimized by locating wellheads away from residences. If the damage to the wellhead also ignited the hydrogen, it would produce an intense, upwardly dispersed, clean-burning, almost invisible flame. The only anticipated product from an accident of this type would be water vapors and oxides of nitrogen. Such an accident could ignite surrounding vegetation and cause injury to anyone involved in the accident; however, the potential for such an adverse impact is considered remote. If the escaping hydrogen is not ignited, it would rapidly disperse in the atmosphere, causing no damage to the surface environment.

Increased noise levels at the compressor station and temporary increases associated with well maintenance and/or rapid release of gas from a wellhead during testing are probably the most significant effects of such a facility. Note that the compressor station is not in operation continuously; it is used only to compress gas in and/or out of the reservoir as dictated by the relative pressures of reservoir and pipeline. Typically for a natural gas storage field, compressors operate only about 3 to 6 months of the year.

Rural agricultural areas have average ambient noise levels of between 45 and 60 db. These levels are due to such things as farm machinery, automobiles, aircraft, and livestock. Increased noise levels outside of the compressor station would be on the order of 70 to 85 db. Distances of 1 mile would provide a sufficient buffer for facilities such as residences, schools, and hospitals.

3. Embrittlement of Metals by Hydrogen

The purpose of our investigation of hydrogen embrittlement is to determine whether equipment used in natural gas storage facilities is suitable for hydrogen service, and, if it is not suitable, what must be changed. There is considerable industrial experience in this country in the handling of high-pressure hydrogen. Petrochemical industries, hydrogenation operations, and retailers of commodity gases all have considerable experience with hydrogen service. In addition, there is a limited base of experience in the design of pipelines for hydrogen service. Table 2 summarizes hydrogen pipeline experience both in this country and in Germany. We contacted representatives of industrial concerns with hydrogen experience to determine how the design equipment for hydrogen service could account for hydrogen embrittlement and whether those designs were general enough to apply to underground storage facilities.

Table 2. SUMMARY OF HYDROGEN PIPELINE EXPERIENCE[47]

Location	Pipeline Steel	Age, yr	Length, km	Hydrogen Purity,%	Hydrogen Pressure MN/m^2	Hydrogen Pressure psi	Comments
Texas	Converted natural gas line	6	8	99.5	6	800	No problems
Texas	New Schedule 40 steel	3	19	99.5	1.4	200	No problems
Germany	Seamless 1015 steel	Up to 35	210	Dirty[a]	1.8	260	No problems
Florida	316 stainless steel	10	1.6	Ultrapure[b]	42	6000	No problems
Los Alamos	5 Cr-Mo steel	8	6	Ultrapure[b]	14	2000	Leaked in 3 yr; cracked in 4 yr; abandoned

[a] Purity unknown, 12 materials transported interchangeably through pipeline.

[b] Liquid boiloff.

The purpose of this section is to define, where possible, the effects of hydrogen embrittlement on equipment at underground hydrogen storage facilities. Of major concern is whether materials of construction currently used in underground natural gas storage facilities are suitable for hydrogen service. Three major topics are discussed:

- Summary of temperature and pressure conditions expected in each of the four specific storage sites examined in this study to determine the worst likely set of temperature and pressure conditions for hydrogen embrittlement
- A general descripton of the types of hydrogen embrittlement reported in the literature, including mechanisms (if known) and those properties that influence the rate and the severity of hydrogen embrittlement
- Summary of the data presented as they apply to the design of underground hydrogen storage facilities, and identification of future research needs in the area of hydrogen embrittlement.

a. Summary of Storage Conditions

The different types of underground storage facilities used in the United States are described in detail in Section A. Table 3 summarizes the maximum wellhead pressures and underground temperatures for the four specific storage sites chosen for detailed study. (Three possible depths are shown from the mined cavern case.)

Table 3. SUMMARY OF STORAGE CONDITIONS

Storage Type	Maximum Wellhead Pressure, psig	Maximum Underground Temperature, °F
Depleted Gas Field	1050	87
Aquifer	900	82
Washed Salt Cavern	3500	160
Mined Cavern		
Depth = 2500 ft	1000	80
3500 ft	1400	90
4500 ft	1800	106

The depleted gas field, aquifer, and shallowest (2500 feet) mined cavern all have maximum pressures below about 1000 psig and maximum underground temperatures below 90°F. The washed salt cavern has the most extreme temperature and pressure (160°F and 3500 psig), and conditions for the deeper mined caverns fall somewhere in between. The pressures shown in Table 3 represent actual maximum values for storage field equipment, with the exception of down-hole well casing and tubing, which will be subjected to somewhat higher pressures. Temperatures at compressor outlets will be much higher than the underground temperatures listed in Table 3. Typical compressor interstage temperatures are 200° to 400°F. Although these higher temperatures will be localized, they must be recognized as we study hydrogen embrittlement.

b. General Description of Hydrogen Embrittlement

The term "hydrogen embrittlement" is not well-defined; it is used to describe a variety of effects of hydrogen on the physical and mechanical properties of metals. The mechanisms that cause hydrogen embrittlement effects also are not well-defined. Factors known to influence the rate and severity of hydrogen embrittlement include internal hydrogen concentration, external hydrogen pressure, temperature, hydrogen purity, type of impurity, stress level, stress rate, metal composition, metal tensile strength, grain size, microstructure, and heat treatment history.

Because the mechanism of hydrogen embrittlement often is not well understood, most studies of hydrogen embrittlement describe effects rather than causes. Embrittlement effects can be divided into a number of different categories; different studies often describe the same embrittlement effects in different terms. We have chosen to follow the nomenclature set forth by a study performed by Battelle Laboratories[21] and will describe seven types of hydrogen embrittlement effects, including -

- Opening of the lattice
- Shatter cracks, flakes, and fisheyes
- Hydrogen chemical attack
- Blistering
- Loss of ductility
- Hydrogen stress cracking
- Hydrogen environment embrittlement.

The first six types of hydrogen embrittlement effects involve internal (dissolved) hydrogen. The seventh type of embrittlement effect (hydrogen environment embrittlement) is the result of hydrogen adsorbed on the surface of metal. A detailed description of the seven embrittlement effects follows.

1) Opening of the Lattice. Metal exposed to very high-pressure hydrogen can become filled with small cracks and fissures. In extreme cases, the metal may become permeable to both liquids and gases. The mechanism for this embrittlement effect is not well understood.[21] However, this type of embrittlement has not been observed at hydrogen pressures below 30,000 psi and, as such, is of no significance to this study.

2) Shatter Cracks, Flakes, and Fisheyes. Shatter cracks, flakes, and fisheyes can occur during the manufacture of metals. The mechanism for this hydrogen effect involves the trapping of molecular hydrogen in the metal lattice during cooling.[21] This problem therefore should not affect hydrogen storage operations.

3) Hydrogen Chemical Attack. The effect of hydrogen chemical attack on metals is the development of fissures, resulting in a loss of both strength and ductility. The mechanism for this embrittlement effect is understood. Hydrogen reacts with carbon in the metal to form methane gas. The methane molecule is too large to diffuse through the metal structure and therefore becomes trapped in voids. Sufficient pressure can be generated by trapped methane gas to cause fissures.[36] The following conditions

and physical properties are known to affect the rate and/or severity of hydrogen chemical attack:

- High hydrogen partial pressures favor hydrogen chemical attack.[44]
- The rate of hydrogen attack on metals increases as temperature increases.[6]
- Both the rate and severity of hydrogen chemical attack are influenced directly by the carbon content of the steel. In general, both rate and severity increase as the carbon content of the steel increases.[21]
- The effect of hydrogen chemical attack on metals increases as the grain size of the metal increases.[55,68]
- The temperature history of the metal affects hydrogen chemical attack. In general, cold-working of metals increases their susceptibility to hydrogen chemical attack.[54]
- The presence of some impurities in hydrogen enhances hydrogen chemical attack. Specifically, moisture,[6] hydrogen sulfide,[46] and carbon monoxide[46] increase the rate of hydrogen chemical attack. These alloying elements and guidelines for material selection have been experimentally determined.
- Various alloying elements in steels reduce chemical attack of hydrogen on carbon by forming very stable carbides.[10,36,43,44] The elements commonly used to decrease hydrogen chemical attack are thorium, zirconium, tantalum, neodymium, titanium, chromium, vanadium, tungsten, and molybdenum.

These guidelines are generally presented in graphical form (Nelson charts) as plots of temperature versus hydrogen partial pressures.[45,47,48] Figure 23 is a typical Nelson chart showing safe design conditions for plain carbon steel and carbon steel alloyed with molybdenum. The areas below and to the left of the lines on the temperature versus partial pressure curves for the various metal compositions are considered safe zones. As indicated in Figure 23, even plain carbon steel exposed to temperatures below 500^{o}F is capable of withstanding very high hydrogen pressures (greater than 1000 psi).[21,68] Because temperatures in hydrogen storage facilities are expected to be below 500^{o}F, we do not expect major problems from hydrogen chemical attack on metals commonly used in natural gas storage facilities.

4) Blistering. Blistering is another hydrogen embrittlement effect whose mechanism is fairly well-understood. Atomic hydrogen diffuses quite rapidly through most metal structures. Molecular hydrogen, on the other hand, does not diffuse and can become trapped in metal structures. In blistering, atomic hydrogen diffuses through a void or defect in the metal structure, recombines at that void to form molecular hydrogen, and cannot diffuse from that void. In such cases, internal pressure in voids due to trapped molecular hydrogen builds up to many times the environmental partial pressure of hydrogen and results in mechanical rupture.[36,67] The following factors are known to increase the blistering of metals exposed to hydrogen environments:

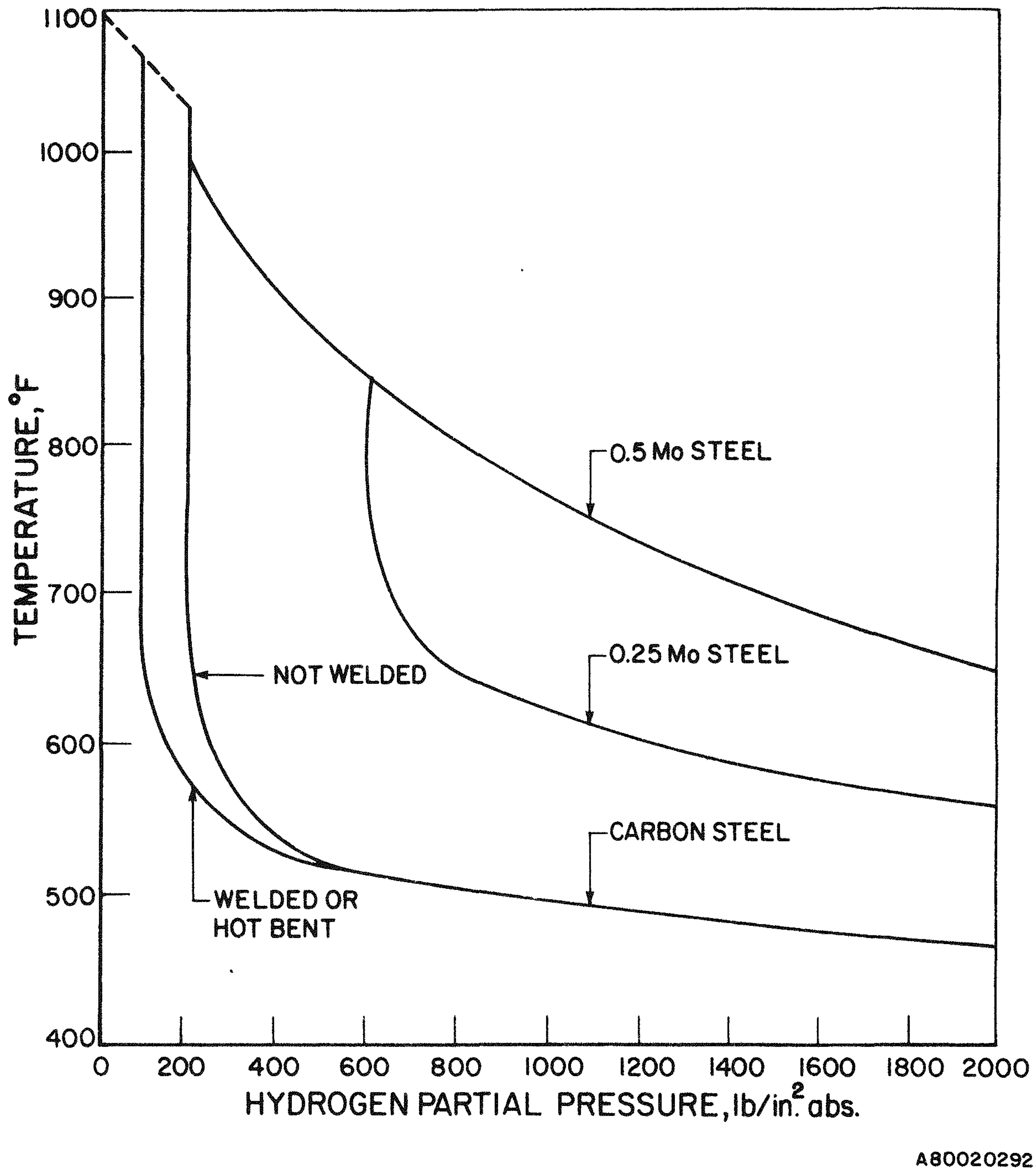

Figure 23. NELSON CHART OF SAFE DESIGN CONDITIONS FOR PLAIN CARBON STEEL AND CARBON STEEL ALLOYED WITH MOLYBDENUM

- Internal imperfections in the metal (laminations, slag inclusions, inclusion stringers) provide sites for the recombination of atomic to molecular hydrogen and increase blistering in metals.[36,49]

- Corrosion of the metal surface[49] and some surface poisons (such as hydrogen sulfide) increase the concentration of atomic hydrogen at the surface of the metal and therefore increase the internal concentration of atomic hydrogen in metal.[9,35]

- Reducing metal temperatures quickly favors the formation of molecular hydrogen and results in incresed blistering effects.[8,35,36]

Blistering may present a problem for some hydrogen storage applications. This potential problem can be controlled by obtaining high-quality metal (as free of defects as possible), by monitoring and minimizing surface corrosion, and by carefully controlling temperature cycling.

5) Loss of Ductility. In the presence of high internal atomic hydrogen concentrations, some metals (especially high-strength steels) exhibit reduced values of tensile elongation, area in tensile tests, and fracture stress. In severe cases, metal may no longer be capable of resisting fracture in regions of high stress near notches and changes in section size. The mechanism for loss of ductility is not well understood. The effect described as loss of ductility may indeed be a combination of other effects of hydrogen embrittlement. The following factors are known to increase loss of ductility in metals:

- Steel tensile strength affects the degree to which ductility losses occur.[30,60,66] In general, the higher the yield strength of the material used, the higher its loss of ductility in hydrogen environments.

- Losses of ductility are especially severe in areas that include imperfections and inclusions.[30,60] The presence of notches also leads to increased ductility losses.[38]

- High internal concentrations of atomic hydrogen (and therefore high external hydrogen pressure) increase ductility losses.[30,35,36,61,66]

- The hardness of the material of construction also is a factor.[30,66] Hard spots, especially near welds, are especially susceptible to ductility losses.

- Losses of ductility are most severe at intermediate temperatures (approximately room temperature) and are less severe above and below room temperature.[25,36,61]

- The rate of strain exterted on a metal also affects the severity of ductility losses in hydrogen service. Ductility losses are most severe at low rates of strain.[12,30,35]

- Cold working of metal increases its susceptibility to loss of ductility in hydrogen service.[35,37,56,60]

Losses in ductility probably will not be a problem for the low-yield-strength materials commonly employed in underground gas storage facilities. Portions of the compressor apparatus are possible exceptions to this general conclusion. In addition, welds and notches can provide sites for severe losses in ductility. The design of hydrogen storage facilities should include use of low-tensile-strength steels wherever possible, proper annealing and welding procedures, and the avoidance of notches, rapid temperature changes, and temperature excursions above or below ambient temperature wherever possible.

6) Hydrogen Stress-Cracking. Hydrogen stress-cracking is an embrittlement effect in which cracks initiate and grow in high-strength steel subjected to stress in the presence of diffusing atomic hydrogen. The mechanism for this embrittlement is not well understood, but the following experimentally determined conditions are necessary for hydrogen stress-cracking[21]:

1) The metal must have a tensile yield strength above approximately 110,000 psi.

2) The steel must be subjected to a minimum sustained tensile stress. That minimum value of stress depends upon the strength of the steel and its hydrogen content.

3) The steel must contain atomic hydrogen moving through the lattice as a result of concentration of stress gradients.

Factors that increase hydrogen stress-cracking include the following:

- Hydrogen stress-cracking is most severe in steels with high yield strengths.[23]
- Hydrogen stress-cracking is most severe at welds and hard spots.[23]
- The level and rate of stress applied to steel affect hydrogen stress-cracking.[23,36] In general, a high rate of stress decreases the transport rate of atomic hydrogen through the metal lattice.
- Cyclic stress loadings make a metal more susceptible to hydrogen stress-cracking.[47]
- The presence of hydrogen sulfide and carbon dioxide appears to increases hydrogen stress-cracking of metals.[47]

Hydrogen stress-cracking can be made less severe by adding small amounts of carbon monoxide, water vapor, or oxygen to hydrogen; oxygen, in particular, in very small concentrations has shown the ability to almost completely eliminate hydrogen stress-cracking.[47] Some researchers[36] have determined that alloying steels with some metals can reduce hydrogen stress-cracking, but this observed phenomenon is not well defined at this time. We conclude that hydrogen stress-cracking probably will not be a major problem in most underground storage systems. Hard spots, especially near and around welds and in some compressor components, may be affected more severely than the remainder of the system.

7) Hydrogen Environment Embrittlement. Hydrogen environment embrittlement is a surface phenomenon in which severe cracks initiate at the metal surface. The mechanism for this embrittlement is not well understood, but two conditions have been experimentally determined to be necessary for this type of hydrogen embrittlement:

1) The metal must be exposed to an external hydrogen environment. Hydrogen environment embrittlement is not affected by internal, atomic hydrogen.

2) The metal exposed to an external hydrogen environment also must be plastically deformed.

The effects of hydrogen environment embrittlement are reversible and do not depend on internal hydrogen concentration. Hydrogen environment embrittlement depends on hydrogen pressure to a limited extent.[26] However, increasing hydrogen pressure by small amounts does not severely increase the rate of hydrogen environment embrittlement. Hydrogen environment embrittlement is much worse in the presence of notches, defects, or changes in section size.[57,64] There are little data available in the literature on the temperature dependence of this hydrogen embrittlement effect.

The presence of small amounts of oxygen almost completely eliminates hydrogen environment embrittlement, even in metals that have been severely deformed.[26] Oxygen in concentrations as low as 1 ppm causes a small reduction in the hydrogen environment embrittlement. Oxygen in concentrations of 1% by volume completely eliminates hydrogen environment embrittlement in deformed metals. If facilities to be used for underground hydrogen storage are carefully designed and inspected, hydrogen environment embrittlement should not be a problem except where metal defects or soil stress cause plastic deformation.

c. Conclusions

Because of a lack of understanding of the basic mechanisms of hydrogen embrittlement, we found that present designs are based on a variety of empirically determined formulas and that no generally accepted method prevails. Factors upon which present designs of hydrogen equipment are based include —

- Nelson charts. These charts are appropriate only for determining the ability of a particular material to withstand hydrogen chemical attack and are not generally applicable to the other hydrogen embrittlement effects noted above.

- A 110-psi yield strength "rule of thumb." The use of low-yield-strength steels reduces the effects listed above as hydrogen environment embrittlement and hydrogen stress-cracking. This rule of thumb generally does not apply to the other forms of hydrogen embrittlement.

- The use of expensive alloys.

- The use of expensive heat-treating and annealing procedures. Here again, heat-treating and annealing are effective in reducing some embrittlement effects, but are not generally applicable to all forms of hydrogen embrittlement.
- Over-design — the use of high safety factors.
- Test of proposed materials of construction at specific conditions.

The existence of a large number of industrial hydrogen-using processes attests to the ability of present design techniques to handle hydrogen service in most cases, but there are documented cases in which equipment has failed for no discernible reason.[52] We conclude that industrial experience is specific to particular applications and not directly applicable to the determination of the ability of equipment designed for methane service to handle hydrogen storage applications.

In our examination of the seven hydrogen embrittlement effects documented in the literature, we determined that the first two (opening of the lattice; and shatter cracks, flashes, and fisheyes) will definitely pose no problems for facilities designed for underground storage of hydrogen. We determined that hydrogen chemical attack, loss of ductility, and hydrogen stress-cracking embrittlement effects probably will pose no problem in moderate-pressure storage operations if proper procedures are followed. Hydrogen chemical attack can be prevented by alloying steels to tie up carbon as stable carbides and avoiding metals that readily form hydrides, such as titanium. The use of low-strength steel and the avoidance of hard spots will help to eliminate loss of ductility and hydrogen stress-cracking problems in equipment designed for hydrogen storage applications. Critical components will be compressor parts and welded zones. Blistering and hydrogen environment embrittlement are likely to be the most severe problems for hydrogen storage facilities.

In summary, we conclude that, if the pressure at storage facilities is limited to values of approximately 1000 to 1200 psi, equipment currently in service at natural gas storage facilities will withstand hydrogen service with respect to hydrogen embrittlement. Therefore, of the four specific sites investigated in this study, only the washed salt cavern and the deep mined cavern sites will require a complete replacement of materials of construction. However, before any given facility is converted from natural gas to hydrogen service (regardless of the pressure level), in-place equipment must be surveyed to determine the number of flaws (which promote blistering and hydrogen chemical attack), hard spots (which promote hydrogen stress-cracking, hydrogen environment embrittlement, and loss of ductility), and plastic deformation (which promotes hydrogen environment embrittlement). A detailed inspection of this type may not be cost-effective at existing storage facilities. In that case, we would recommend replacement of all welded sections subjected to pressures above several hundred psig. In order to avoid hydrogen embrittlement, we suggest that the following criteria be applied to the design of facilities for underground hydrogen storage systems:

- Use low-yield-strength steel whenever possible.
- Use heat-treated and fully annealed materials.
- Use careful welding procedures to avoid hard spots and flaws.
- Maintain a careful inspection of all materials for flaws, including voids, inclusions, and hard spots.
- Design for minimum stress levels in all components (particularly cyclic stress).
- Avoid plastic deformation of all materials at all costs.
- Possibly, use an oxygen impurity at low concentration levels to control hydrogen stress-cracking and hydrogen environment embrittlement.

4. Reactions of Hydrogen with Chemical Species Found in Underground Reservoirs

The four major storage reservoirs types – 1) sandstone, 2) depleted field, 3) salt dome, and 4) mined cavern – are composed of, or in contact with, rock strata of the following general types: 1) sandstone, 2) shale, 3) limestone, 4) dolomite, 5) anhydrite, 6) gypsum, 7) silt stone, 8) reef, 9) salt, and 10) granite.[32] Each of these strata may be characterized by both lithology and, more importantly, mineralogy.

Sandstone, depleted field, and mined cavern reservoirs are composed primarily of stable, nonreactive silicate minerals consisting of quartz, feldspars, and lesser amounts of garnets, spinels, and micas. However, minor sulfide, sulfate, carbonate, and oxide minerals often occur either as cementing materials or as small crystals coating the surfaces of larger grains. In limestone, dolomite, and salt caverns, these minerals may become major in quantity. Because of the large amount of exposed surface area of these minerals in sandstone-type reservoirs, in excess of the quartz itself, and the large quantity of these minerals in limestone and salt reservoirs, possible reactions with hydrogen could proceed to the complete consumption of the reacting mineral. This might involve measurable quantities of hydrogen and the generation of toxic gases. Primarily these minerals are the 1) sulfides S, FeS, FeS_2, PbS, HgS, ZnS, Cu_2S, $CuFeS_2$, CS_2; 2) sulfates $CuSO_4$, $CuSO_4 \cdot 2H_2O$; 3) carbonates $CaCO_3$, $MgCO_3$, $(Ca, Mg)CO_3$; 4) oxides Fe_2O_3, Fe_3O_4, FeO, MgO, and minor chemical species in the gases in the reservoir, CO, CO_2 and hydrocarbons. Walters[65] stated that hydrogen loss in a depleted oil field, through hydrogenation and cracking, as well as loss in an aquifer, due to chemical reaction, would not be significant without higher temperatures or catalysis. After a year of operation, withdrawal from the Beynes Field, France, in 1957 produced trace quantities of nickel and iron carbonyls (see Section II-A-2-e). In addition, it was necessary to desulfurize, dry, and oxygenate the manufactured gas before scrubbing out the carbonyls.[39] Trace amounts of carbonyls, before scrubbing, were found to form deposits, resulting in disruption of safety devices, stoppage of pilot lights, and opacification of glass. The mechanism for formation of the $Ni(CO)_4$ and $Fe(CO)_4$ was postulated to involve reaction between carbon monoxide gas in the manufactured gas and trace metal salts in the reservoir through adsorption and desorption due to manufactured gas and natural gas interface motions.

Because of the minor hydrogen sulfide in the Beynes Field and indications of minor chemical reactions, it was decided to compile thermodynamic data for the minerals listed to determine the possibility of reactions with hydrogen taking place with minerals in the reservoir. A complete chemical model involving chemical species dissolved in groundwater and multicomponent chemical equilibria was not attempted because dissolved species, though more reactive, would be in quantities significantly smaller than the trace minerals themselves.

For reactions with hydrogen, a reaction equation can take the form:

$$aH_2 + bB \rightleftarrows cC + dD \quad (6)$$

where –

a, b, c, d = stoichiometric quantities

B, C, D = different chemical species.

By adding the free energies of formation of the components for temperatures and pressures similar to those in the reservoir, the direction of reaction can be determined. The most stable chemical configuration in a reaction exhibits the minimum free energy. The minimum free energy configuration is indicated if the free energy of the products minus the reactants is negative, or for Equation 6 –

$$Ag = cG_c + dG_D - bG_b - aRT\ell n\, P_{H_2} \quad (7)$$

where –

AG = free energy of the reaction

G = free energy of the formation

and assuming: Fugacity for hydrogen at P, T is nearly 1.

Table 4 lists some of the reactions considered and the free energies of the reactions, assuming a reservoir temperature of 298°K (77°F) and pressure of 2000 psi. An increase in temperature of as much as 50°F would not change reaction directions nor would reaction directions be changed by decreases in pressure. Only reactions 1, 2, and 11 indicate possible reaction with hydrogen. However, these three reactions require either temperatures above those in reservoirs or catalysis.

Table 4. APPROXIMATE FREE ENERGIES OF REACTIONS INVOLVING HYDROGEN AND SOME RESERVOIR MINERALS

		Free Energy, kcal
(1)	$H_2 + O_2 = H_2O$	-54.64
(2)	$H_2 + S = H_2S$	-7.892
(3)	$H_2 + FeS = H_2S + Fe$	12.520
(4)	$H_2 + FeS_2 = H_2S + FeS$	5.720
(5)	$H_2 + PbS = H_2S + Pb$	11.350
(6)	$H_2 + Cu_2S = H_2S + 2Cu$	15.616
(7)	$H_2 + CaSO_4 = H_2SO_3 + CaO$	45.767
(8)	$H_2 + CaSO_4{\cdot}2H_2O = H_2SO_4 + Ca(OH)_2$	42.519
(9)	$2H_2 + 2CaCO_3 = 2H_2O + 2CO_2 + 2Ca^{2+}(aq)$	385.962
(10)	$H_2 + FeO = Fe + H_2O$	6.668
(11)	$H_2 + 3Fe_2O_3 = 2Fe_3O_4 + H_2O$	-11.241
(12)	$H_2 + Fe_3O = 3Fe + H_2O$	12.732
(13)	$H_2 + CaF_2 = 2HF + Ca^{2+}(aq)$	21.811
(14)	$2H_2 + SiO_2 = Si + 2H_2O$	379.40
(15)	$3H_2 + Al_2O_3 = 2Al + 3H_2O$	206.7

Similar to inorganic reactions, most hydrogenation and cracking reactions require temperatures in excess of normal reservoirs. Some anaerobic bacteria are capable during fermentation processes of reducing hydrogen and sulfates to hydrogen sulfide and water, but this activity is rare in reservoirs for short times. In past geologic time, all the hydrogen reacted to hydrogen sulfide or escaped.

For the Beynes Field, at the time of conversion, all gas analyses of injected and withdrawn natural gas over the previous 10 years were examined. There was some change in the hydrogen content of the injected gas over this period, but analysis of the withdrawn gas followed this change exactly.

Further evidence of the absence of significant hydrogen reactivity was given by analysis of gas that had leaked through the caprock into a shallower reservoir. This leak was through a poorly centered well and was withdrawn from an observation well some 100 meters from the leak. The upper reservoir was a low-permeability clay-sand mixture. Gas analysis corresponded to the "older" injected gas, not higher in hydrogen than the maximum that was originally injected. This confirmed that selective diffusion of hydrogen through the caprock did not take place and that hydrogen could co-exist with the underground rock strata for long periods.

Although the reactions and the cases studied here cannot be considered to represent the full range of possible reactions that could occur in a reservoir, with the lack of theoretical prediction and actual occurrence of hydrogen reaction, there is little evidence for serious problems with underground storage for long periods.

5. Purity Requirements of Hydrogen Delivered Storage Reservoirs

The purity required of hydrogen delivered from storage will be determined by both end use and by the physical requirements of the transmission and distribution systems for hydrogen delivery. The specifications for transmission and distribution pipelines are not likely to be substantially different than those for natural gas service. The possible exception here is water vapor content, which is limited in natural gas service by hydrate formation. Water vapor content in hydrogen transmission and distribution lines probably will be limited only by condensation, and therefore, water vapor specifications are likely to be less severe than for natural gas. The end use of hydrogen (which we assume is a fuel) will determine hydrogen purity based on what is required for burners designed for hydrogen service. Methane from mixing in the converted storage fields will be the primary concern. To our knowledge, no one has determined the maximum allowable methane content in hydrogen or burners designed for hydrogen. This knowledge should be developed in future research programs.

There have been studies on the other end of the spectrum, i.e., the maximum allowable hydrogen content in natural gas. These studies conclude that 10% to 20% (by volume) hydrogen is acceptable for most methane burners. An exception here is target burner pilots, which will require minor adjustments for hydrogen contents of 20%. For methane burners, the higher flame speed of hydrogen compared to that of methane is the critical factor that limits hydrogen concentration in natural gas. Because of the higher flame speed of hydrogen, flashback results if too much hydrogen is added to natural gas. Because hydrogen burners will be designed for a fast flame front, the methane content in hydrogen is expected to pose fewer burner problems than hydrogen in methane. However, we cannot define an actual upper limit on methane concentrations in hydrogen. An investigation of allowable methane concentrations in hydrogen burners (catalytic and noncatalytic) should be the topic of future research programs.

If the end use of hydrogen delivered from storage is as a commodity rather than as a fuel, the end use of hydrogen must be specified before an accurate determination of hydrogen purity requirements for that purpose can be made. Such a detailed assessment is beyond the scope of this program and will not be considered.

III. CURRENT COSTS OF UNDERGROUND NATURAL GAS STORAGE (TASK 3)

A. Format and Methodology Development

The objective of this task is to develop an economic analysis that corresponds to that used by a utility in forecasting the cost of service provided by a contemplated facility. Utilities act as monopolies in the public interest: Facility capital and operating costs are passed on to the end user. Any facility that has associated costs and acts upon the utility's product adds cost to the product equal to the revenue required to operate the facility divided by the facility throughput. This requirement often is hard to delineate, and different accounting principles can yield different revenue requirements.

With limited capital expenditure budgets, all corporations must make intelligent decisions on the type of facilities to construct and/or operate. As a result, a method for evaluating all investment decisions on an equal basis is sought and employed by corporations.

1. Background

Two basic approaches exist to judge the economic feasibility of a project: the payback analysis and the discounted cash flow (DCF) techniques.

The payback analysis is the most simple and direct. The firm simply calculates the length of time required to cover or "pay back" the investment from revenues. This type of analysis is excellent for small businesses that lack the ability to raise capital for investment. This analysis also is excellent for small and large businesses that have cash flow difficulties. One major drawback of this methodology is that the "time value" of money is not considered. An expected return of a certain amount in the future is usually not valued as highly as the same amount paid in full in the present. In actuality, given monies in the present, investment options are available on which to earn monies in excess of the principal amount as time progresses; i.e., money has a time value. The payback analysis does not consider those time-value financing costs associated with paying back a facility construction loan. In addition, the method assumes that earnings in the future are worth the same as those in the present.

Most large corporations that are not suffering severe cash flow problems use an economic analysis methodology based on the concept that money has a time value. The general term for these analyses is "discounted cash flow (DCF) analysis" because the future earnings and expenses making up the cash flow are discounted back to a particular year for comparison. Several basically similar approaches are used for this type of analysis; two are the net present value (NPV) method and the internal rate of return (IRR) method.

In the net present value approach, the present value of the expected net cash flows of an investment is calculated and discounted as the cost of capital. From this value, the initial cost outlay of the project is subtracted. Then –

$$NPV = \left[\frac{CF_1}{(1+i)^1} + \frac{CF_2}{(1+i)^2} \cdots + \frac{CF_n}{(1+i)^n} \right] - P1 \qquad (8)$$

where –

CF represents cash flow

P1 represents initial project costs

i represents the cost of capital.

With this type of calculation, a positive NPV indicates an acceptable project. Assuming corporate investment constraints, only affordable projects with the greatest NPV would be acceptable. For this method, of course, the internal rate of return as well as all capital costs and cash flows must be known or assumed.

The internal rate of return (IRR) approach assumes that the internal rate of return is not known. The objective is to calculate an interest rate that equates the present value of expected future receipts to the capital cost of the investment. The equation is similar to that for the NPV analysis except for rearranging terms and setting the NPV equal to zero.

$$P1 = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} \qquad (9)$$

Then, both the NPV and IRR approach are the same except that, in the former, the i is specified and the NPV is found. In the latter, the NPV is specified as zero, and the required i is found. The calculated rate of return is usually compared to that desired by the corporation at the project risk level. Projects providing a rate of return equal to or greater than the IRR required by the corporation are possibilities for funding to the extent of available capital.

For utilities, which are the most likely corporate candidates to operate either natural gas or hydrogen storage fields, the internal rate of return can be well estimated; it is ensured within limits by the public utilities commission. When a DCF analysis is performed, a form of the NPV analysis should be used. The general form usually is modified to calculate future revenue requirements from a present amount or value. The interest factor, i, is the utility's assumed or anticipated internal rate of return. For utilities, this must represent their cost of capital. Then a NPV of zero resulting from an analysis would indicate a rate of return equal to the cost of capital assumed. This does not imply that the corporation is "breaking even"; it is earning profit as permitted by its rate of return constraints.

With the capital costs, facility life, operating expenses, tax structure, and debt and equity service defined, the utility then can calulate the revenue required to operate the facility. This revenue required becomes the cash flow required as an input to the present value equation. The present value of these revenue requirements then can be calculated by applying the present value factor $1/(1 + i)^n$ for each required yearly revenue. Also, if the throughput is known for each year, the annual cost of service can be calculated. With utilities, the required revenue must be passed on as the cost of service. As might be expected, the cost of service changes yearly because expenses change yearly.

If a single number is desired for comparing various choices, a levelized number is sought. This number can be calculated first by applying an annuity factor to the sum of all years present value of revenue requirements. The annuity concept essentially means that once the total present value of revenue requirements is known, the yearly equal amounts, annuity, or "levelized" payments over the project life, equivalent to the total in terms of present value, can be determined. This yearly amount, the levelized revenue requirements, then is divided by the throughput to yield a levelized cost of service.

Another choice that must be made is whether inflation rates should be considered. If an analysis is being used for comparison, as DCF analyses should be used, and if the facilities under consideration have similar cost areas and percentages of cost in each area, then a constant dollar analysis is more meaningful than an analysis that introduces variables to describe inflation effects. For this report, a constant dollar analysis based on 1978 dollars was assumed.

For this project, we developed a computerized DCF analysis by using constant dollars in a form of the net present value approach. The methodology has been modified from the standard textbook approach to reflect financing specific to utilities. This includes consideration of the "Allowance for Funds Used During Construction" (AFUDC) in the utility rate base.

This analysis assumed that base gas was financed along with facility construction; that is, base gas was purchased and financed during the construction period for delivery after construction completion. As a result of financing base-gas purchases, this gas cost becomes a part of the AFUDC calculations. This technique of financing base gas was considered important for a study of hydrogen storage facilities because base-gas costs could be a large percentage of the facility cost and not supplied by the parent company to the storage facility. For comparison, in some analyses the base gas was not financed, but considered to be a one-time cost.

Because the economic justification of any facility must gain approval from a public utility commission (PUC and/or the Federal Energy Regulatory Commission), our analysis was based on PUC filings to help ensure compatibility with financial practices.

For this project, the computer program was tested extensively on data from operating or planned natural gas storage fields before it was applied to hydrogen storage. Details of the computer program used in this analysis are presented in Appendix D.

2. Parametric Variables

The development of the economic analysis methodology required input data from the participating gas companies. These data were required to test the methodology under development for general agreement with the cost of service methods and resulting operating experience or predictions of the utilities. Data were provided by gas company participants on three natural gas storage fields. One, a depleted gas field that started operation in 1965, was constructed at what seems today to be a very low cost of $3.6 million.

A second field, a washed salt cavern, started operation in 1977 after a cost of development of approximately $17.6 million. A third field, an aquifer, is not yet in service. Based on 1975 filling costs, this aquifer would have had a construction cost of $62.7 million. Capital cost data also were provided by Dames and Moore for an excavated cavern site to be constructed. The cost data provided by Dames and Moore included documented bid estimates for each aspect of the excavation and completion.

Before analysis results are presented, note that the cost of constructing any storage facility depends upon the year the facility was constructed, the type of facility, its capacity, and its intended duty cycle for the utility. Utilities must plan facilities based on their regional needs and demands. For example, a Midwest utility would have little desire to operate a Southwest storage facility if daily peak loads were its concern for storage. Unfortunately, underground formations that could provide low-capital-cost facilities do not exist in all regions of the country. Therefore, some utilities must plan for the use of what might appear to be higher-capital-cost facilities because of regional requirements and the lack of formations that lend themselves to low capital costs. There is no choice in the matter; if underground storage is required, the natural geologic formations in the area must be considered regardless of the capital cost of development. If the capital cost is too great, alternatives must be investigated by the utility.

The storage facility capacity and the intended duty cycle play a major role in the facility's operating economics. Doubling the throughput per year without noticeable changes in operating costs reduces the cost of service by a factor of two. On the other hand, increasing daily output from a facility or reducing base gas below that usually intended could have a limited effect on the average cost of service over the year while increasing the marginal cost of service for a brief period beyond acceptable limits to the facility manager.

Table 5 presents the capital cost of the three storage fields in terms of dollars current to the year in which they were built. The economic analysis program was conducted by using these capital costs for test cases.

However, of major concern to this project is construction of new similar fields for hydrogen use or retrofit of existing fields for hydrogen use. In the former case, the capital cost of the new field would reflect present costs, which for this study are assumed to be 1978 dollars. In the latter case, multiple alternatives exist. The company operating the existing field might sell it for the cost new less depreciation or for any cost as low as the remaining investment pending sale circumstances. Alternatively, a subsidiary might be formed to buy the existing field at a similar cost to provide earnings for alternative investment by the parent company and an initial capitalization requirement for the subsidiary. This study assumed that the capital cost of all facilities analyzed, except for a few cases, represents the cost new in 1978 because neither of the constructed fields has depreciated significantly compared to their new replacement cost.

For the depleted field, new-construction capital costs were estimated by the operating company. The estimate was not claimed to be precise; unless construction bids are sought, it is difficult to know the cost of a facility with great precision. The approximate cost, $9.5 million less the unrecoverable gas, is used as a base case in this analysis. For the aquifer and salt-cavern fields, the capital costs provided by the companies were in 1975 and 1977 dollars, respectively. An adjustment factor of 6%/yr was applied to increase these costs to 1978 dollars. This percentage, based on the Chemical Engineering magazine's cost index,[18] provides sufficient precision for these calculations, because actual construction costs based on bids could vary by more than the imprecision of this escalation factor. The resulting base-case capital costs for the

Table 5. CAPITAL COST ESTIMATES FOR NATURAL GAS STORAGE FACILITIES

	Cost		
Item	Aquifer, 1975 dollars X 10^3	Salt Cavern, 1977 dollars X 10^3	Depleted Field, 1965 dollars X 10^3
Land and Land Rights	1,247	408.6	22.4
Structures and Improvements	655	718.1	95.6
Storage Wells and Reservoirs	5,500	8,114.7	2,151.8
Storage Lines	16,565	1,883.1	966.3
Compressor Station Equipment	3,270	3,269.6	NA
Storage Measurement and Regulation	NA	72.4	NA
Storage Dehydration	NA	279.4	NA
Nonrecoverable/Noncurrent Gas	25,630	671.6	681.3
Other Capitalized Equipment and Expenses during Construction	2,826	56.6	361.0
Labor and Supervision	2,831	781.0	NA
Allowance for Funds Used during Construction	4,232	1,382.2	NA
Total Capitalized	62,764	17,637.3	3,598.2*

* Not including original nonrecoverable gas.

aquifer and salt-cavern fields are \$39.5 million and \$16.4 million, respectively, less the nonrecoverable or noncurrent gas. Application of the same factor over the 14 years since the depleted field was constructed would result in a capital cost of approximately \$8.2 million. A 7% escalation adjustment per year results in a \$9.3-million capital cost, which is comparable to the company estimate.

For the excavated-cavern case, capital-cost estimates were provided for the 2500-ft, 3500-ft, and 4500-ft excavation levels. These estimates were $53 million, $50 million, and $47 million, respectively. The estimates included two shafts, one with a diameter of 24 ft, costing $1200/ft, and the other with a diameter of 6 ft, costing $300/ft. Purchase of excavation equipment is included in the capital cost, as is $5 million for surface equipment. The estimates included two possibilities for construction cost credits: one is sale of rock from excavation, and the other is the use of miners rather than higher salaried construction workers for the excavation work. Partial credits for each were considered for cases in this analysis.

Detailed operating and maintenance costs for the two natural gas storage fields currently in use were gathered from their respective companies. Data as detailed as possible also were gathered for the aquifer field based on the FERC filing and contact with the owners. In addition, operating and maintenance costs for the excavated cavern were estimated based on those costs experienced for operating the salt cavern. These costs were adjusted for relative working gas capacities and used directly as excavated-cavern operating costs for two cases. For conservative cost-of-service calculations, the scaled operating costs for the excavated cavern were increased by a factor of 1.5 for most of the cases tested. In actuality, the excavated cavern is not expected to have any dimensional instability problems often associated with salt caverns; the operating costs should be no more than those of the salt dome. Tables 6, 7, and 8 present the annual operating and maintenance costs for the aquifer, depleted-field, and salt-cavern reservoirs, respectively. Base cases for natural gas operation assumed annual operating and maintenance costs of $200,000, $1.2 million, $350,000, and $500,000 for the depleted field, aquifer, salt-cavern, and excavated-cavern cases, respectively.

Table 6. OPERATING AND MAINTENANCE EXPENSES FOR AQUIFER RESERVOIR

Expense Item	Third Year	Fourth Year	Fifth Year	Sixth Year
	$			
Total Operating Expenses	428,000	913,000	792,000	855,000
Total Maintenance Expenses	157,000	270,000	301,000	311,000
Leases and Royalties	--	8,000	8,000	8,000
Grand Total	585,000	1,191,000	1,101,000	1,174,000

Table 7. OPERATING AND MAINTENANCE EXPENSES FOR DEPLETED-FIELD RESERVOIR

Expense Item	1976 Cost, $	1977 Cost, $	1977 Cost, % of total	1977 Labor, % of total
Operating Expenses				
Structures		6,157.29	5.5	3.3
Wells				
Lines		17,131.47	15.4	9.3
Compressor Station		55,912.29	50.0	42.0
Fuel		5,208.81	4.7	
Lubrication		424.05	0.4	
Measurement		460.91	0.4	0.2
Purification		1,031.63	0.9	0.02
Subtotal		86,330.53		
Supervision		24,552.00	22.1	22.1
Total	111,643	110,853.00	99.4	59.8
Maintenance Expenses				
Structures		3,421.85	14.7	1.7
Wells		1,956.59	8.4	0.08
Lines		1,388.04	6.0	1.4
Compressor Station		9,165.51	39.4	15.9
Measurement		91.40	0.4	0.3
Purification		25.99	0.11	0.11
Subtotal		16,049.88		
Supervision		7,202.00	31.0	31.0
Total	52,506	23,252.00	100.0	50.5
Leases and Royalties	5,172	5,221.00		
Grand Total	169,276	139,326.00		

For each FERC operating and maintenance account indicated in the tables, labor costs and the labor percentage of the total item also are presented. Because labor costs were not available for the aquifer field (for which construction has not yet begun), these data are omitted.

The next major input considered for both the natural gas and hydrogen cases is the throughput per year. The throughputs are constrained by market demands for gas, reservoir parameters, and surface equipment at the field. As a result, a field could have

Table 8. OPERATING AND MAINTENANCE EXPENSES FOR SALT-CAVERN RESERVOIR

Expense Item	1975 Cost, $	1975 Cost, % of total	1975 Labor, % of total	1976 Cost, $	1976 Cost, % of total	1976 Labor, % of total	1977 Cost, $	1977 Cost, % of total	1977 Labor, % of total
Operating Expenses									
Power	13,700	10.3	0	49,501	18.4	0	14,323.84	6.4	
Structures									
Wells	351 (?)	~0	0	--	--	--			
Lines									
Compressor Station									
Fuel	76,270	57.4	0	84,848	31.5	0	84,221.45	38.2	0
Lubrication	2,682	2.0	0	5,664	2.1		6,920.24	3.1	0
Measurement	7,000	5.2	1.2	5,937	2.2	1.7	1,646.07	.75	~0
Purification							139.00	~0	0
Subtotal	100,000			145,950			107,249.00		
Supervision	18,300	13.[illegible]	~13.8	21,700	8.1	7.9	22,834.81	9.6	~9.6
Total[a]	132,812	100.0		268.624			220,370.04	100.0	22.7
Maintenance Expenses									
Structures	14,914	27.2	19.3	12,849	6.5	1.9	27,075.60	22.0	3.7
Wells	5,945	10.8	4.1	8,505	4.3	~0.7			
Lines									
Compressor Station	11,071	20.2	9.8	37,731	19.3	7.6	31,885.23	26.2	5.3
Measurement	4,638	8.8	6.9	7,422	3.8	2.0	10,308.15	8.4	3.6
Purification	806	~1.5	~1.95	916.20	~0	~0	251.67	0	~0
Subtotal	37,374			67,423.00			42,445.05		
Supervision	11,844	21.6	21.4	13,895	7.0		14,509.15	12.0	11.6
Total[a]	54,716			195,872		~0	121,626.47	100	36.9

[a] Includes other expenses not itemized.

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a potential throughput higher than that experienced in meeting market demand. Similarly, a reservoir might be expanded, based on market demand and reservoir parameters, to include additional surface equipment. Moreover, operation of a particular reservoir depends not only on these factors but also on the operation of and demands upon all other storage and transmission facilities integrated to serve the same utility market.

3. Methodology Verification

By using the economic model described above and the operating characteristics of each reservoir, a levelized cost of service for a base case was determined for each reservoir. Some base-case parameters for each reservoir are unique to that reservoir. For example, the base cost of natural gas stored is $0.30/10^6$ Btu for the salt cavern because that was the actual cost in 1975 when the cavern storage was begun. Similarly, the anticipated cost of $1.60/10^6$ Btu used for the aquifer was based on a 1977 startup. Other parameters such as cost of debt or plant lifetime are the same for all four. The objective of this analysis, therefore, is not to compare one type of field with another, but to establish the validity of the economic model. After the levelized cost of service was determined for each field, the economic parameters were varied one at a time to observe the sensitivity of the cost of service. This analyses is especially important because the cost of the gas (hydrogen) that might ultimately be stored is unknown at this time and because the cost of equity and cost of debt are rising to levels that were unanticipated a few years ago. Also, this type of analysis highlights those cost items that influence the cost of hydrogen service in a manner that is different from natural gas service.

In addition, certain aspects peculiar to each field were examined in more detail. For example, a lower capital cost for the excavated cavern can be obtained by selling the rock produced from the excavation or by using labor costs for miners instead of those for construction workers during excavation. Each field and its analysis are discussed in detail below.

a. Salt Cavern

Table 9 lists the base-case economic parameters for the salt cavern. As mentioned above, the low cost of the base gas, $0.30/10^6$ Btu, is based on 1975 values, and the computed cost of service of $0.58/10^6$ Btu is an appropriate value according to the operating company of the field.

Table 9. ECONOMICS OF STORING NATURAL GAS IN A SALT-CAVERN RESERVOIR

Item	Base Case	Percentage Variation
Erected Plant Cost, $\$10^3$	16,400	-5 to +30
Annual Throughput, 10^{12} Btu	6.2	--
Cost of Base Gas, $\$/10^6$ Btu	0.30	+900
Annual Operating Cost, $\$10^3$	350	-50
Construction Time, yr	3	-60
Cost of Debt, %	10	-50 to +100
Cost of Equity, %	15	-60 to +30
Fraction Debt Financed	0.60	-60 to +30
Lifetime for Economics, yr	27	
Cost of Service, $\$/10^6$ Btu	0.58	-36 to +41

The parametric values were varied as indicated in Table 9, and the results are plotted in Figure 24. Figure 24 summarizes the parametric variations; the exact computational results are found in Appendix E. The lines in Figure 24 represent the levelized cost of service as a function of the percentage change in the variable. All the lines go through the point that represents the levelized cost of service for the base case. The cost of service is most sensitive to the parameters with the steepest slope. For the salt cavern, the most sensitive parameter is the erected plant cost; the least sensitive is the cost of the gas.

b. Aquifer

The base-case economics for storing natural gas in an aquifer are illustrated in Table 10. The levelized cost of service is $\$2.07/10^6$ Btu for a base-gas cost of $\$1.60/10^6$ Btu. This cost of service is based on an annual throughput of 6.6×10^{12} Btu. Figure 25 illustrates the sensitivity of the cost of service to variation in the parameters in Table 10. As was the case for the salt cavern, the cost of service is most sensitive to the plant cost and cost of equity. For the aquifer, the least sensitive parameters are the operating costs and construction time.

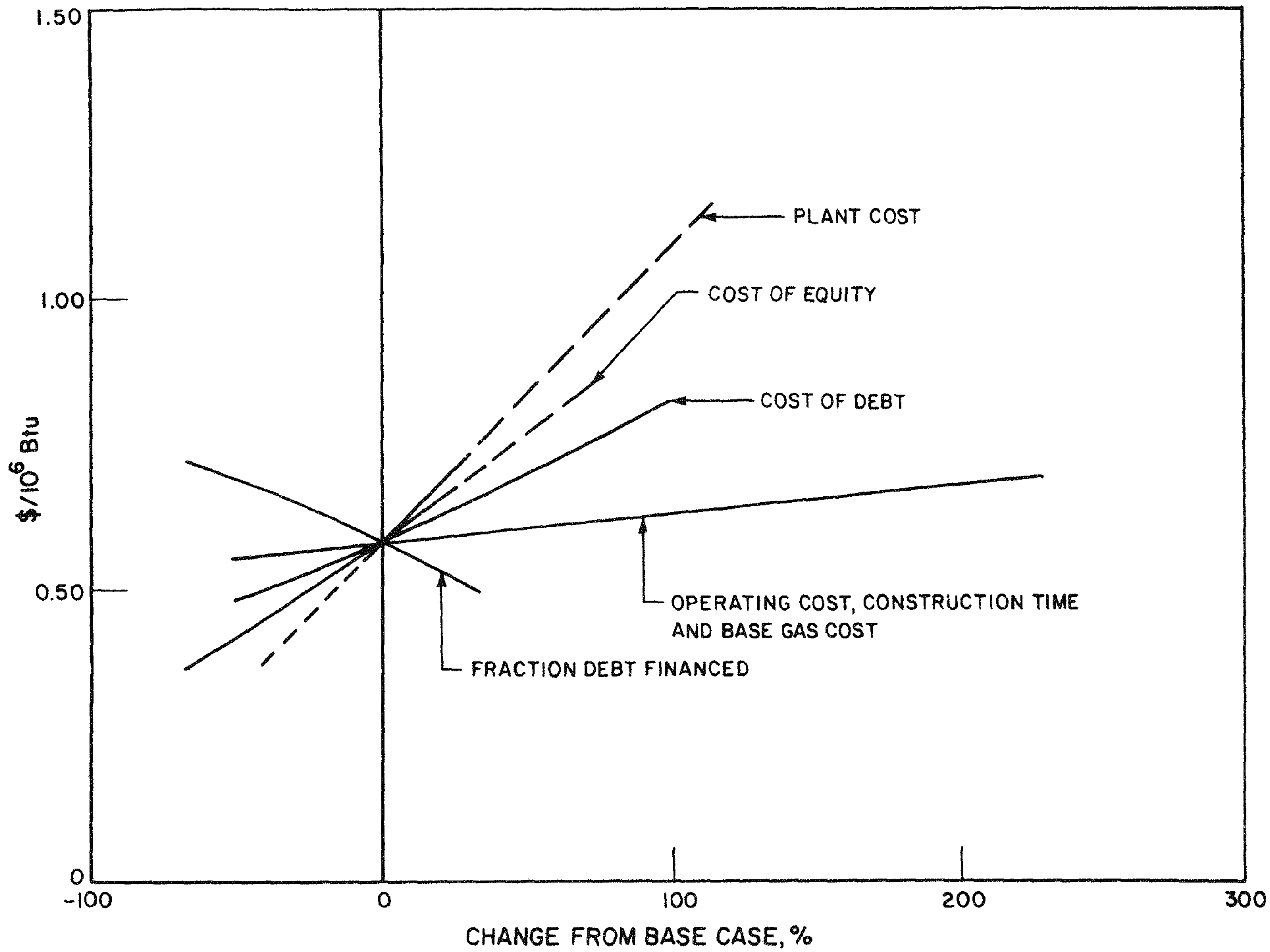

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Figure 24. COST-OF-SERVICE SENSITIVITY PLOT FOR STORING NATURAL GAS IN A SALT-CAVERN RESERVOIR

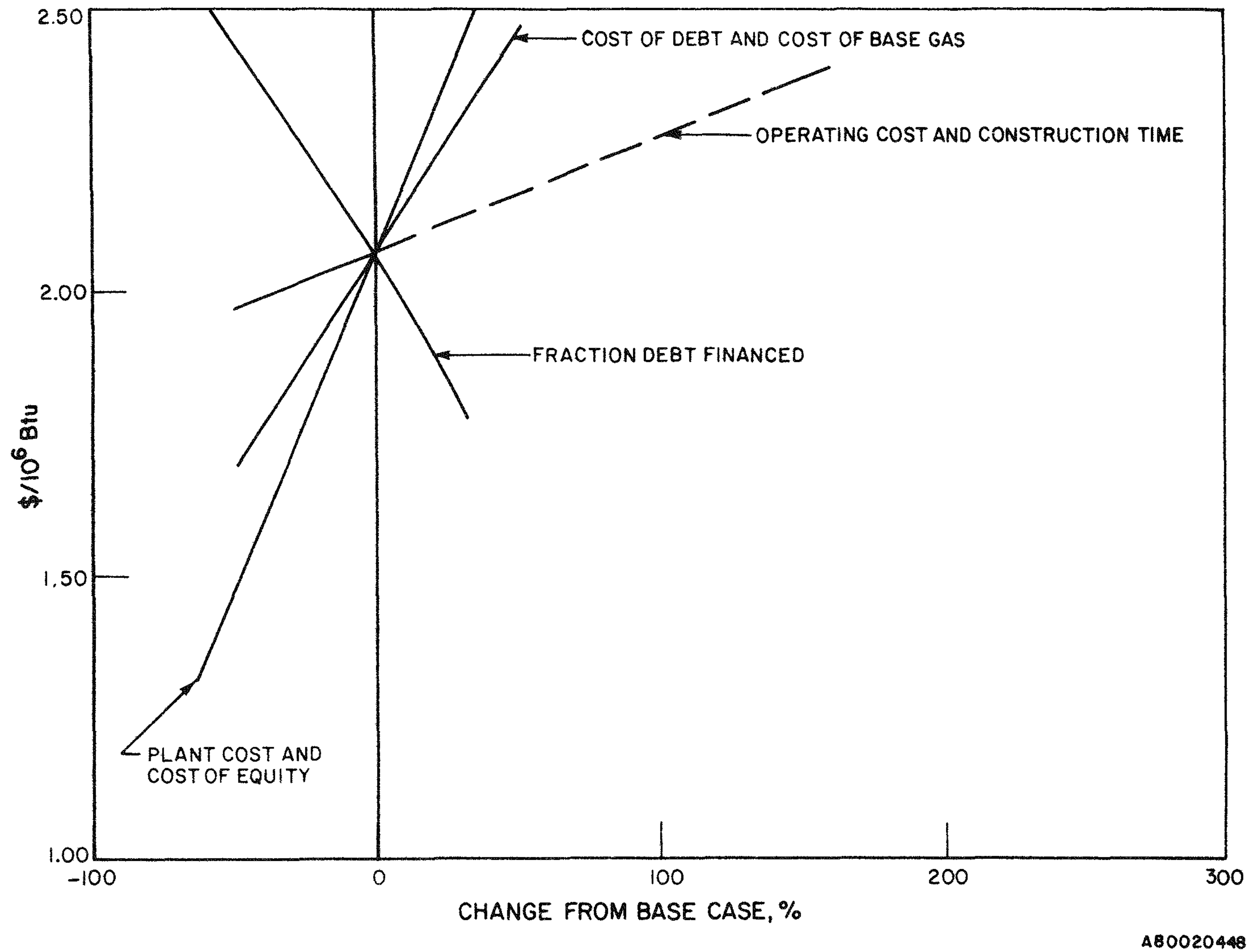

Figure 25. COST-OF-SERVICE SENSITIVITY PLOT FOR STORING NATURAL GAS IN AN AQUIFER RESERVOIR

Table 10. ECONOMICS OF STORING NATURAL GAS IN AN AQUIFER RESERVOIR

Item	Base Case	Percentage Variation
Erected Plant Cost, $\$10^3$	39,500	-15 to +30
Annual Throughput, 10^{12} Btu	6.6	--
Cost of Base Gas, $\$/10^6$ Btu	1.60	to 90
Annual Operating Cost, $\$10^3$	1,200	-50
Construction Time, yr	3	-60
Cost of Debt, %	10	-50 to +100
Cost of Equity, %	15	-60 to +30
Fraction Debt Financed	0.6	-60 to +30
Lifetime for Economics, yr	27	--
Cost of Service, $\$/10^6$ Btu	2.07	

c. Excavated Cavern

The levelized cost of service for the base case of the excavated cavern is given in Table 11. Because no excavated cavern exists that was designed primarily to store natural gas, there are no actual costs of service with which to compare the computed cost. However, for an annual throughput of 8.0×10^{12} Btu and a base-gas cost of $\$1.00/10^6$ Btu, the cost of service is $\$1.30/10^6$ Btu. This is a reasonable value, which is larger than that for the salt cavern, for example, because the base-gas cost is higher and the erected plant cost is very high.

The sensitivity analysis illustrated in Figure 26 again shows that the most sensitive parameters are the plant cost and the cost of equity. The least sensitive parameter is the cost of base gas. The above analysis considers an excavated cavern with a depth of 2500 feet. If deeper caverns are considered, i.e., to 3500 ft and to 4500 ft, the base-case cost of service drops to $\$1.18/10^6$ Btu and $\$1.11/10^6$ Btu, respectively, if the excavated rock is sold and miners are used instead of construction workers. The effect of increased compression costs (appearing as larger plant cost) is more than offset by the larger storage volume for the 4500-ft depth.

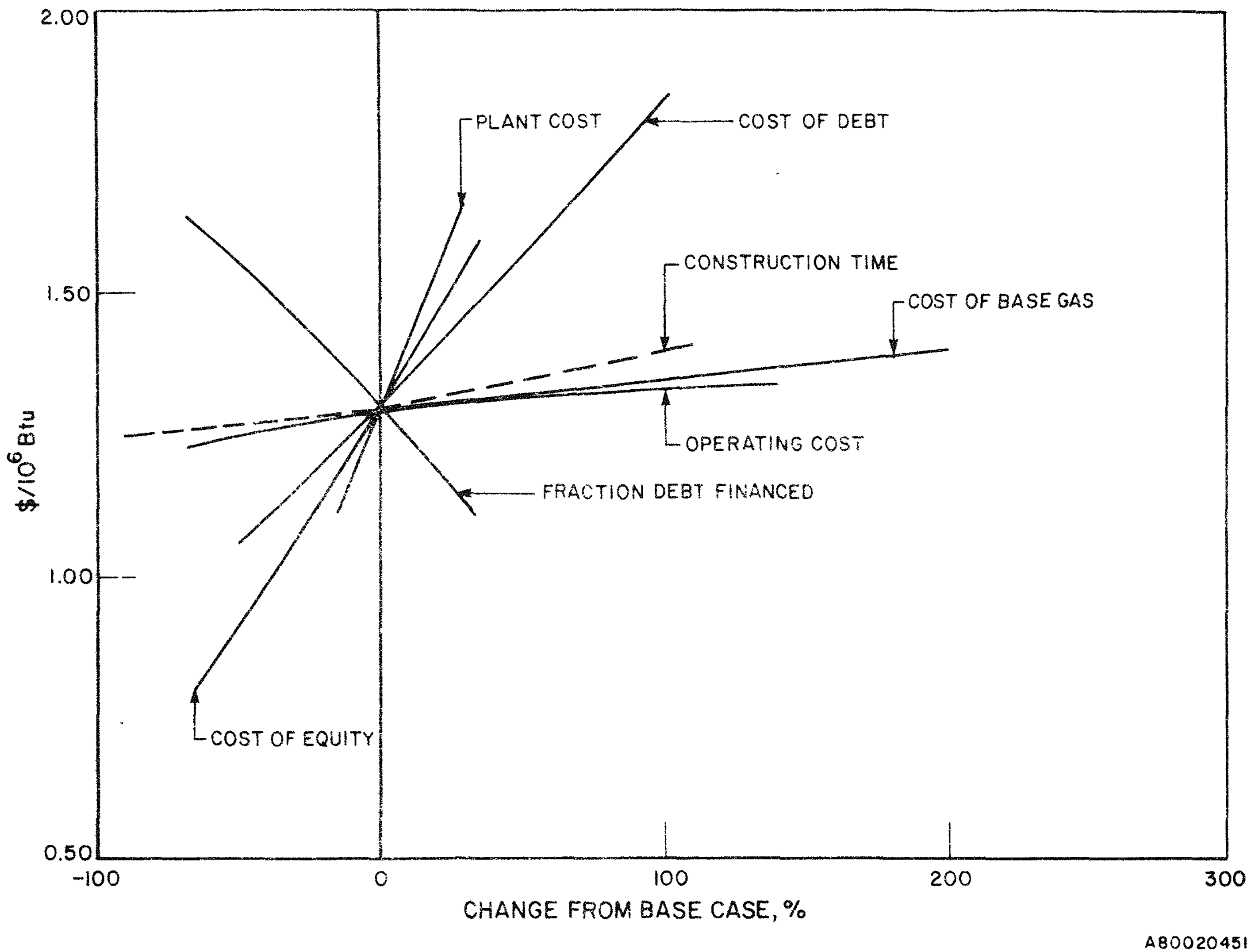

Figure 26. COST-OF-SERVICE SENSITIVITY PLOT FOR STORING NATURAL GAS IN AN EXCAVATED-CAVERN RESERVOIR

Table 11. ECONOMICS OF STORING NATURAL GAS IN AN EXCAVATED-CAVERN RESERVOIR

Item	Base Case	Percentage Variation
Erected Plant Cost, $\$10^3$	50,000	-3 to +30
Annual Throughput, 10^{12} Btu	8.0	--
Cost of Base Gas, $\$/10^6$ Btu	1.00	to +200
Annual Operating Cost, $\$10^3$	500	-50
Construction Time, yr	3	-60
Cost of Debt, %	10	-50 to +100
Cost of Equity, %	15	-60 to +30
Fraction Debt Financed	0.6	-60 to +30
Lifetime for Economics, yr	27	--
Cost of Service, $\$/10^6$ Btu	1.30	

d. Depleted Field

As shown in Table 12, the cost of service for the depleted-field base case is $\$0.88/10^6$ Btu for a base-gas cost of $\$1.00/10^6$ Btu and an annual throughput of 3.080×10^6 Btu. As was the case for all other reservoirs, the plant cost and cost of equity affect the cost of service more than the other parameters. (See Figure 27.)

e. Conclusions

The results of the test of the economic methodology on natural gas storage show that the method does accurately predict the levelized cost of service. This prediction, however, must be considered in the context of the assumptions made in the model. In particular, the model assumes a fixed amount of gas is injected and withdrawn in every year of the computational history, that the amount of gas considered to be the "base" gas remains fixed, and that the operating costs per year remain fixed. None of these assumptions are held exactly in the actual operation of a reservoir, nor should they be. For the most part, the model is insensitive to very small changes in most of the parameters and is even insensitive to large changes in others such as yearly operating costs.

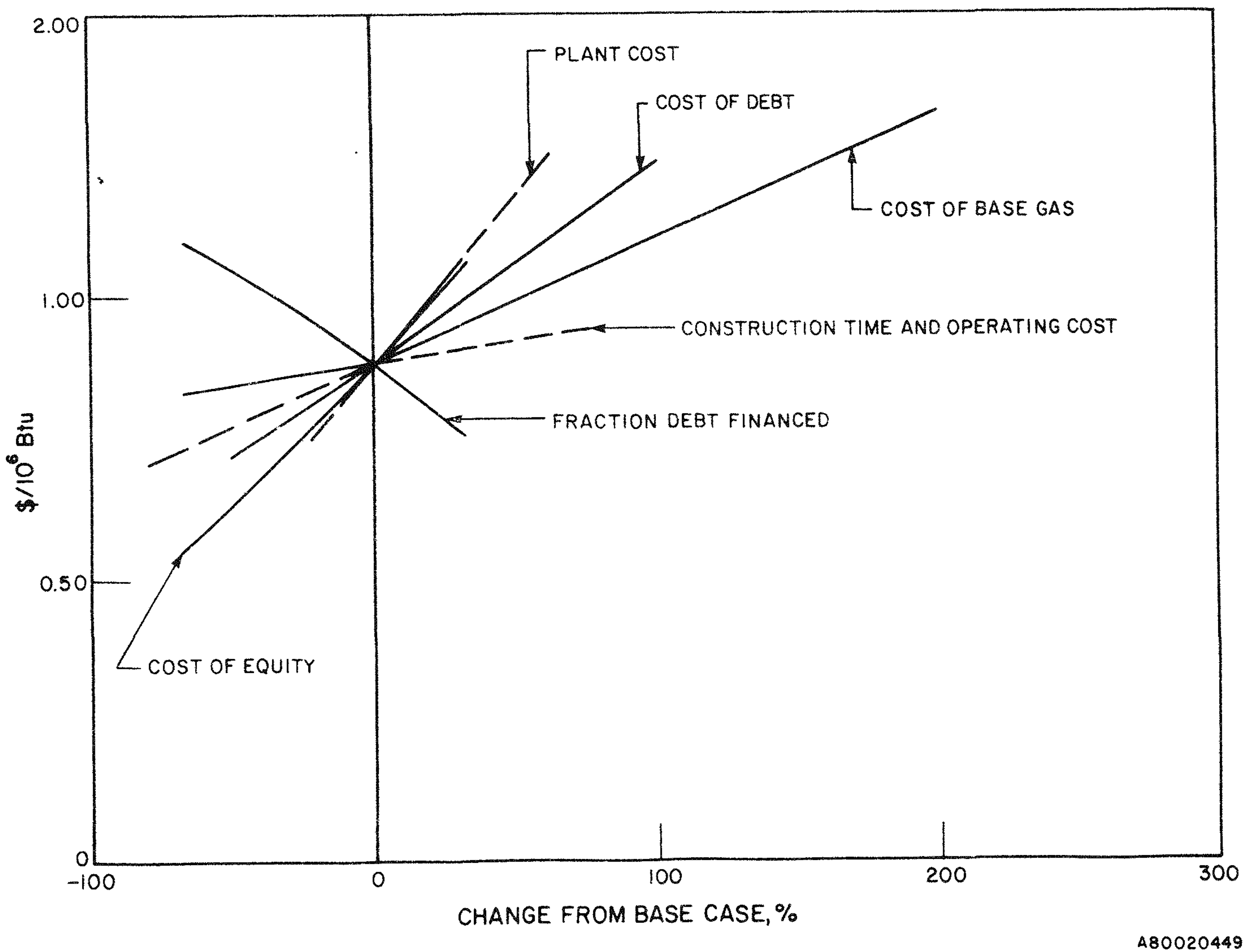

Figure 27. COST-OF-SERVICE SENSITIVITY PLOT FOR STORING NATURAL GAS IN AN A DEPLETED-FIELD RESERVOIR

Table 12. ECONOMICS OF STORING NATURAL GAS IN A DEPLETED-FIELD RESERVOIR

Item	Base Case	Percentage Variation
Erected Plant Cost, $\$10^3$	9,500	-3 to +30
Annual Throughput, 10^{12} Btu	3.08	--
Cost of Base Gas, $\$/10^6$ Btu	1.00	to +20
Annual Operating Cost, $\$10^3$	200	-50
Construction Time, yr	3	-60
Cost of Debt, %	10	-50 to +100
Cost of Equity, %	15	-60 to +30
Fraction Debt Financed	0.6	-60 to +30
Lifetime for Economics, yr	27	
Cost of Service, $\$/10^6$ Btu	0.88	

The absolute value of the levelized cost of service depends on the absolute value of the base-case parameters. The sensitivity of the cost of service to any of the parameters depends on their value relative to one another. So, for example, in the excavated-cavern case both the plant cost and cost of base gas are high and contribute to the high cost of service. The ratio of the base-gas cost to the plant cost is approximately the same for the excavated cavern as for the other reservoirs, so that the shape of the sensitivity plot is about the same as the others, merely shifted up in cost of service.

A caution to be observed in extrapolating the lines in the sensitivity figures is that only the solid lines represent computed data. The dashed lines are extrapolations for the sake of clarity. To determine the cost of service for values beyond the solid portion, the best procedure is to execute the program in Appendix D.

B. Economic Assessment of Hydrogen Storage

1. Equipment Changes for Hydrogen Storage Facilities

We have examined wells and aboveground equipment at underground gas storage facilities to determine 1) the changes or modifications to existing equipment that would be required in converting natural gas storage facilities to hydrogen service and 2) the design differences that would be required in developing new storage facilities dedicated to hydrogen service. The following analysis is based on four specific storage fields that are typical of four different types of storage applications: depleted fields, aquifers, washed salt caverns, and mined caverns. Changes in or modification of equipment for use at storage facilities designed for hydrogen (as opposed to natural gas) service are outlined generally for all four types of storage fields. The depleted natural gas storage facility examined in this study was chosen for detailed analysis in Task 4. Therefore, we provide additional details on the equipment changes required for the depleted-field case. We have estimated the cost for equipment changes only for those items identified in a preliminary economic analysis as having a significant impact on the cost of service; those items include wells, gas compression equipment, and pipefields. Changes in equipment that do not have a significant impact on the cost of service are simply identified; no detailed cost estimates have been prepared. Where appropriate, we have identified specific reasons (safety considerations, materials compatibility, changed physical properties) for the required changes in equipment at underground hydrogen storage locations.

a. Basis for Study

The design of underground gas storage facilities depends on both the total storage gas volume and on the injection-withdrawal cycle assumed for a particular field. The methods used to determine hydrogen storage volume and hydrogen deliverability (injection-withdrawal cycles) are outlined below.

b. Hydrogen Storage Volume

Most underground gas storage facilities, including the four studied here, are operated in a pressure swing mode, that is, between a maximum pressure (generally occurring at or near the end of an injection season) and a minimum pressure (generally occurring at or near the end of a withdrawal season). The amount of gas contained in any particular field is a function of the field's temperature, pressure, and void volume according to the relationship expressed by Equation 10.

$$PV = znRT \tag{10}$$

The total amount of gas in any field can be divided into two general categories. The difference in the amount of gas between the temperature, pressure, and volume existing at the end of the injection cycle and the temperature, pressure, and volume existing at the end of the withdrawal cycle is the total amount of gas (working gas) cycled through the storage field in a season. The gas contained in the field at the lowest pressure that is necessary to support the storage operation, but is not cycled, is termed base gas. In general, the highest pressure used in a given storage field corresponds closely with the hydrostatic pressure at the particular depth of the field. Hydrostatic pressure is about 0.43 psia/ft of depth.

The amount of hydrogen working and base gas was calculated for each of the four fields studied here by assuming the same maximum and minimum field pressures used in (or postulated for) natural gas operation. Because the temperature and underground void volume for three of the four fields (depleted gas field, washed salt cavern, mined cavern) remains relatively constant at all times, Equation 10 was used to calculate hydrogen, "working," and base gas volumes for those fields directly. In the aquifer, however, the movement of water into and out of the gas storage zone makes the total void volume available for gas a variable along with pressure. Therefore, a more detailed analysis was required to determine working and base gas requirements for the aquifer field.

Because aquifer storage requires movement of the water preexisting in the reservoir, the actual structure, or geometrical, configuration of the reservoir and surrounding region must be determined. The structure, or elevation contours, of the top of the Galesville formation are shown in Figure 28. On the assumption that the Galesville formation is approximately constant in thickness, profiles through the structure can be drawn as shown in Figure 28. The structure is thus seen to be elliptical and nicely arched for a storage reservoir.

The gas storage volume is determined by the amount of pore space exposed when the water is swept away by the advancing mobile gas unit. This is shown schematically in Figure 29, in which it is assumed that, as gas is injected into the high point of the dome, the pressure in the mobile gas unit is approximately constant and the gas-water contact is approximately horizontal. The amount of available pore volume per cubic foot of reservoir sandstone then is equal to the pore space in the rock reduced by the amount of residual, or irreducible, water that remains trapped in the surfaces and in the small recesses of the pores. By using the porosities and residual saturation data reported in the filing document along with the contour data, the available pore space can be determined. This is tabulated in Table 13 and shown graphically in Figure 30 for natural gas storage. The quantity of natural gas that can be stored over the possible ranges of operation is given in Table 14.

The initial pressure in the water at the reservoir depth of approximately 2000 feet below ground level is hydrostatic pressure of approximately 840 psi. From this it can be assumed that the aquifer is an open system, but with the external boundary at some far distance away from any significance or influence on the storage project.

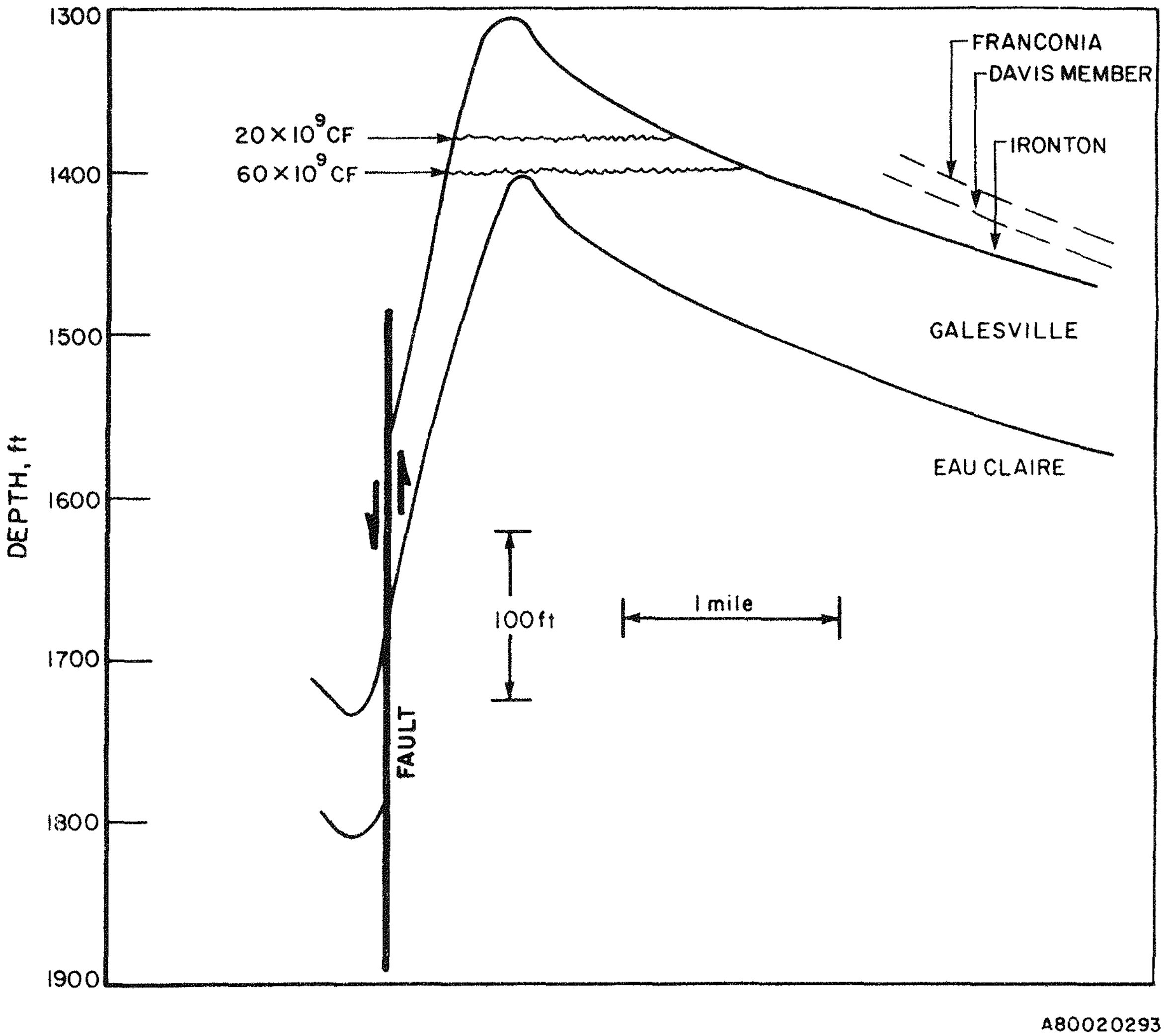

Figure 28. PROFILE THROUGH AQUIFER

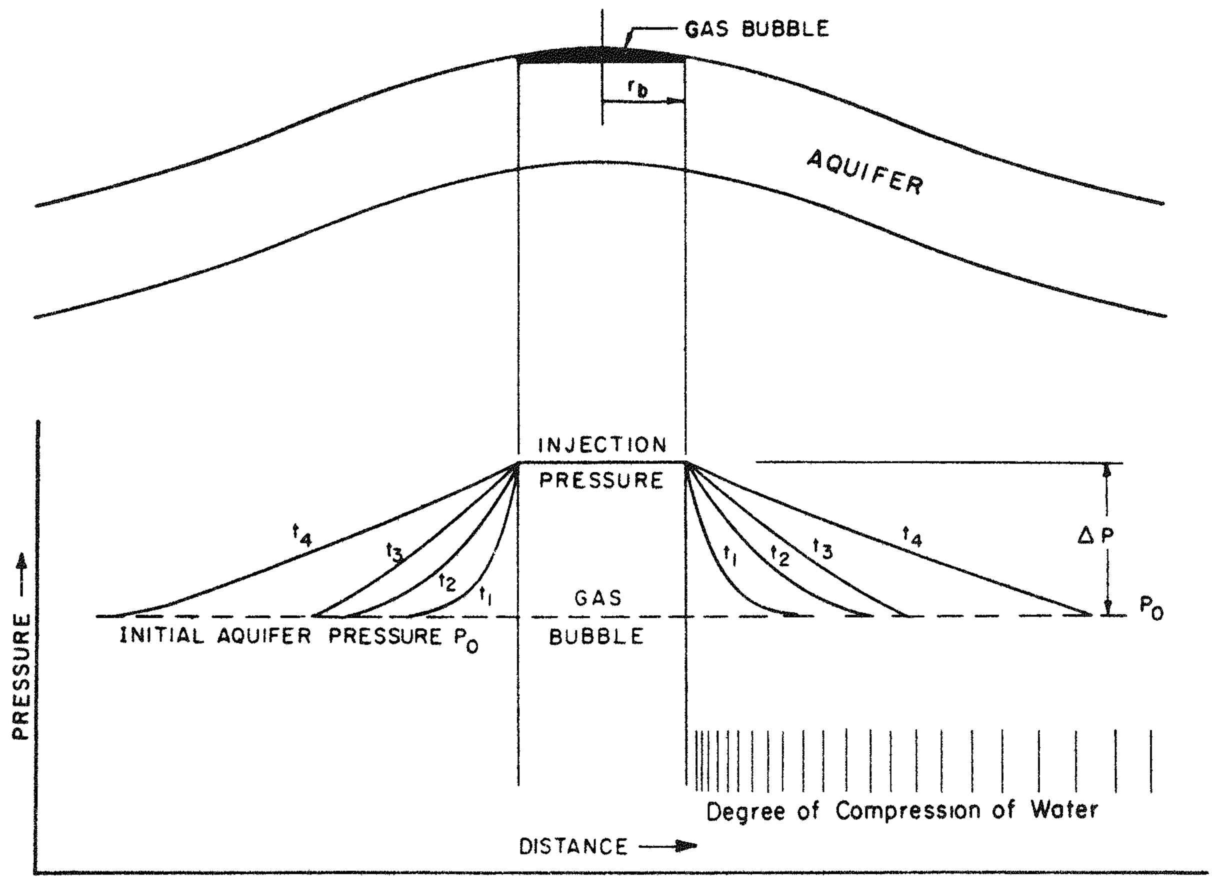

Figure 29. GAS MOVEMENT IN AN AQUIFER

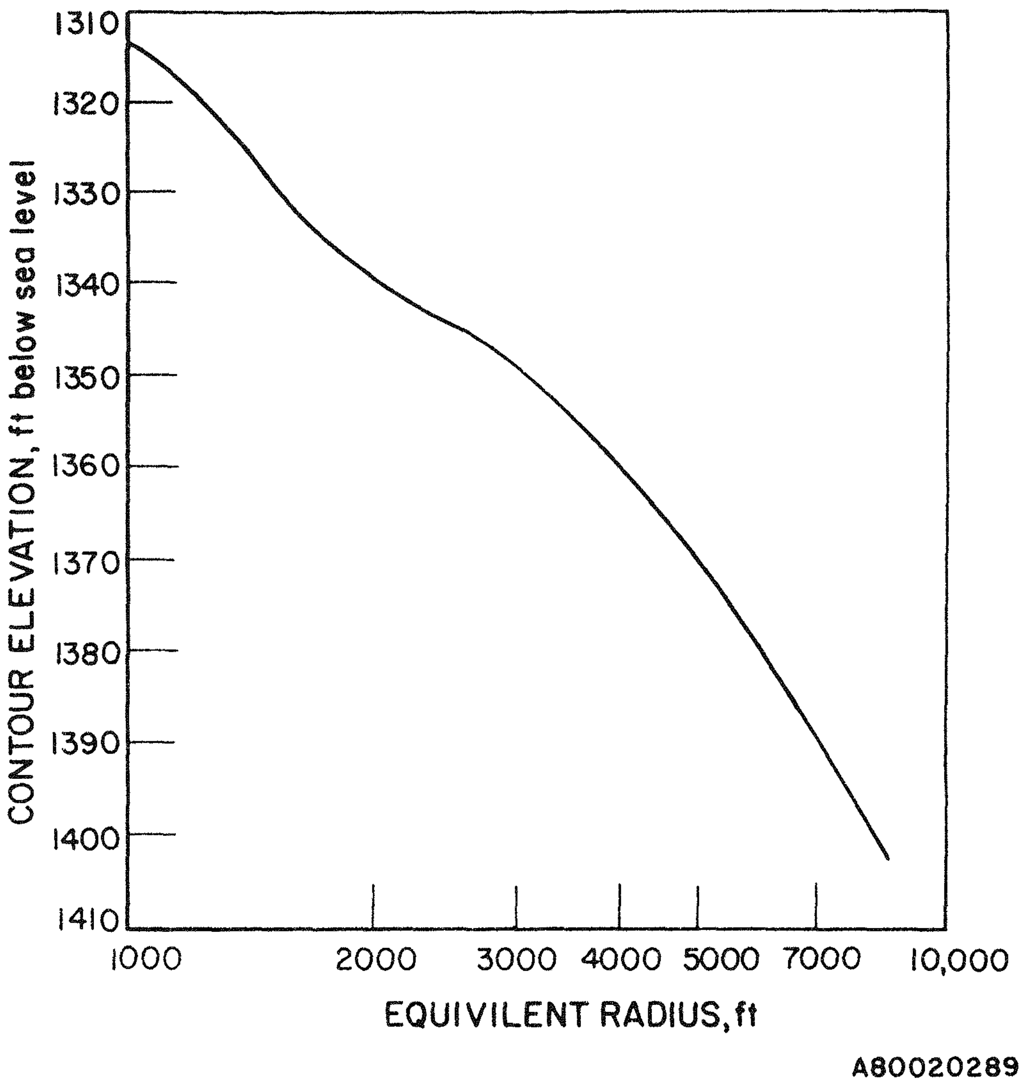

Figure 30. EQUIVALENT RADIUS FOR CONTOUR AREAS IN THE GALESVILLE FORMATION

Table 13. VOLUMETRIC CAPACITY OF AQUIFER STORAGE FIELD IN GALESVILLE FORMATION

Contour[a] Depth, ft-SLE[b]	Bubble[a] Thickness, ft	Contour[a] Area, acres	Equivalent[c] Radius, ft	Pore[d] Volume, 10^6 CF
-1300	7	63.7	117	1.4
-1320	17	113.5	1255	6.9
-1330	27	174.6	1556	15.9
-1340	37	295.0	2022	30.6
-1350	47	742.6	3209	63.0
-1360	57	1215.5	4105	124.1
-1370	67	1793.4	4987	218.2
-1380	77	2510.8	5900	352.7
-1390	87	3512.1	6978	540.8
-1400	97	4747.8	8114	798.9

[a] From Exhibit H-18 of FPC filing.

[b] SLE = sea-level elevation.

[c] Contour area assumed to be a circle.

[d] Using 17.2% pore volume and 16.6% connate water.

The size of the storage gas unit depends on the applied gas pressure and time. It does not matter whether the gas is hydrogen or natural gas. To create the mobile gas unit, gas must be injected at a pressure above hydrostatic, or above 840 psi. The strength and sealing characteristics of the caprock control the extent to which the injection pressure can exceed the hydrostatic pressure. The excess pressure must not fracture the caprock or drive out the sealing fluids that are held in place by capillary forces. Also, if the mobile gas unit is formed when the driving pressure is too high, there is fingering of the water and the pores can not drain adequately down to the irreducible or connate saturation. This excess water lowers the available pore space and also the permeability to the gas flowing through the pore network.

Table 14. VOLUMETRIC CAPACITY OF AQUIFER FORMATION FOR NATURAL GAS STORAGE

Mobile gas unit			Gas Content[c]				
Contour, ft SLE[a]	Thickness, ft	Area,[b] acres	640 psia	840 psia[d]	890 psia	940 psia	990 psia
			10^6 SCF				
-1310	7	63.7	66	89	95	101	108
-1320	17	113.5	328	445	473	503	536
-1330	27	174.6	753	1,023	1,088	1,156	1,232
-1340	37	295.0	1,447	1,964	2,089	2,221	2,367
-1350	47	742.6	2,980	4,045	4,302	4,574	4,874
-1360	57	1,215.5	5,873	7,972	8,478	9,013	9,606
-1370	67	1,793.4	10,317	14,006	14,895	15,836	16,877
-1380	77	2,510.8	16,676	22,637	24,074	25,594	27,277
-1390	87	3,512.1	25,573	34,715	36,919	39,250	41,830
-1400	97	4,747.8	37,775	51,279	54,535	57,978	61,789

[a] SLE = sea-level elevation.

[b] Aquifer structure map.

[c] $V = 43{,}560 \times \text{acre-ft} \times \quad \times (1 - Sw) \times 1/F$

where V = gas content, 10^6 CF

$\text{Acre-ft} = \frac{h}{2}(A_1 + A_2)$

h = contour interval, ft

$A_{1,2}$ = area within successive contours

= porosity = 17.2%

Sw = connate water = 16.0%

$F = 10^6 \times \frac{P_b}{P} \times \frac{T}{T_b} \times Z$

P_b = pressure base = 14.73 psia

P = reservoir pressure, psia, at a datum of −1320 SLE[a]

T = 532°R, 72°F reservoir temperature

T_b = 520°R, 60°F temperature base

Z = compressibility factor.

[d] Original pressure.

In an aquifer storage project, such as this one, the gas-water interface is moving continuously. When the pressure in the gas unit is above the initial in-situ pressure, the gas unit expands, and when the pressure is lowered below the initial pressure, the gas unit contracts. The dynamics of the motion of the gas-water contact are controlled by the geometry of the system and the physical properties of the gas, water, and rock. In theory, the motion can be calculated, but in practice, the mathematics are so complex and the parameters so uncertain that detailed calculations usually are not performed. Instead, simplifying assumptions are made and engineering approximations are made by using analytical equations that are adequate for design estimates.

The method used in Table 15 to calculate the rate of water movement is the method described by Katz,[32] in which the rate of water egress is calculated from the "influence function." In Table 15 the assumed bubble radius is approximately equal to the equivalent radius shown in Figure 30 that corresponds to 20 billion CF storage in Tables 13 and 14. The model assumes that the reservoir is circular and infinite in lateral extent. The assumed circular shape should be an adequate representation of the actual ellipsoidal shape seen in the structure map (Figure 31) for engineering design purposes. With this circular geometry assumption, the analytical method described by Katz can be used to approximate the water movement in the operating reservoir.

The above assumptions about the mobile gas unit formation assume that the reservoir gas pressure is constant. There is some pressure differential between the well bore and the outer edge of the gas unit that can be approximated by the steady-state flow equation. The steady-state equation can be used because the "readjustment time," or the time for a pressure transient to move from the well bore to the outer radius, is small compared to the flow times.

The readjustment time is calculated by the equation –

$$t_r = \frac{947 \mu \ \phi \ r_e^2}{k \ p} \tag{11}$$

where –

t_r = readjustment time, hr

μ = viscosity, cP

ϕ = porosity, dimensionless

r_e = effective reservoir radius, ft

k = permeability, md

p = average gas pressure, psi

Table 15. CALCULATION OF RATE OF DEVELOPMENT OF THE MOBILE GAS UNIT IN THE GALESVILLE FORMATION

Assumed Conditions

Radius of gas bubble = 6,000 ft (r_b)

Porosity of sand = 17.2% (ϕ)

Permeability of sand = 448 md (k)

Compressibility of rock and water = 7 x 10^{-6} (c)

Effective thickness of sand = 100 ft (h)

Pressure in gas bubble minus aquifer pressure = 1000 psi (ΔP)

Water viscosity = 1.0 cP (μ)

Formula

where –

$q = 0.00628\phi \ c \, r_b^2 \, h \, \Delta P \, Q_t$

q = cumulative water movement rate, 1000 CF

Q_t = dimensionless quantity, function of t_D

t_D = dimensionless time = $\frac{0.00633 \, kt}{\phi c \, r_b^2}$

t = time, days

$q = 0.00628 \times 0.172 \times (7 \times 10^{-6}) \times 100 \times 600^2 \times 100 \, Q_t = 2{,}722 \, Q_t$

$$t_D = \frac{0.00633 \times 448t}{0.172 \times 7 \times 10^{-6} \times 6000^2} = 0.06543 \, t$$

Time (t), days	t_D	Q_t	q, 1000 CF	q/t, 1000 CF/day	Injection, 1000 CF/day at 940 psia
50	3.271	3.389	9,225		
				$\frac{7,730}{70}$ = 110.4	8,029
120	7.851	6.229	16,955		
				$\frac{11,912}{130}$ = 91.6	6,662
250	16.357	10.605	28,867		
				$\frac{9,451}{115}$ = 82.2	5,978
365	23,880	14.077	38,318		

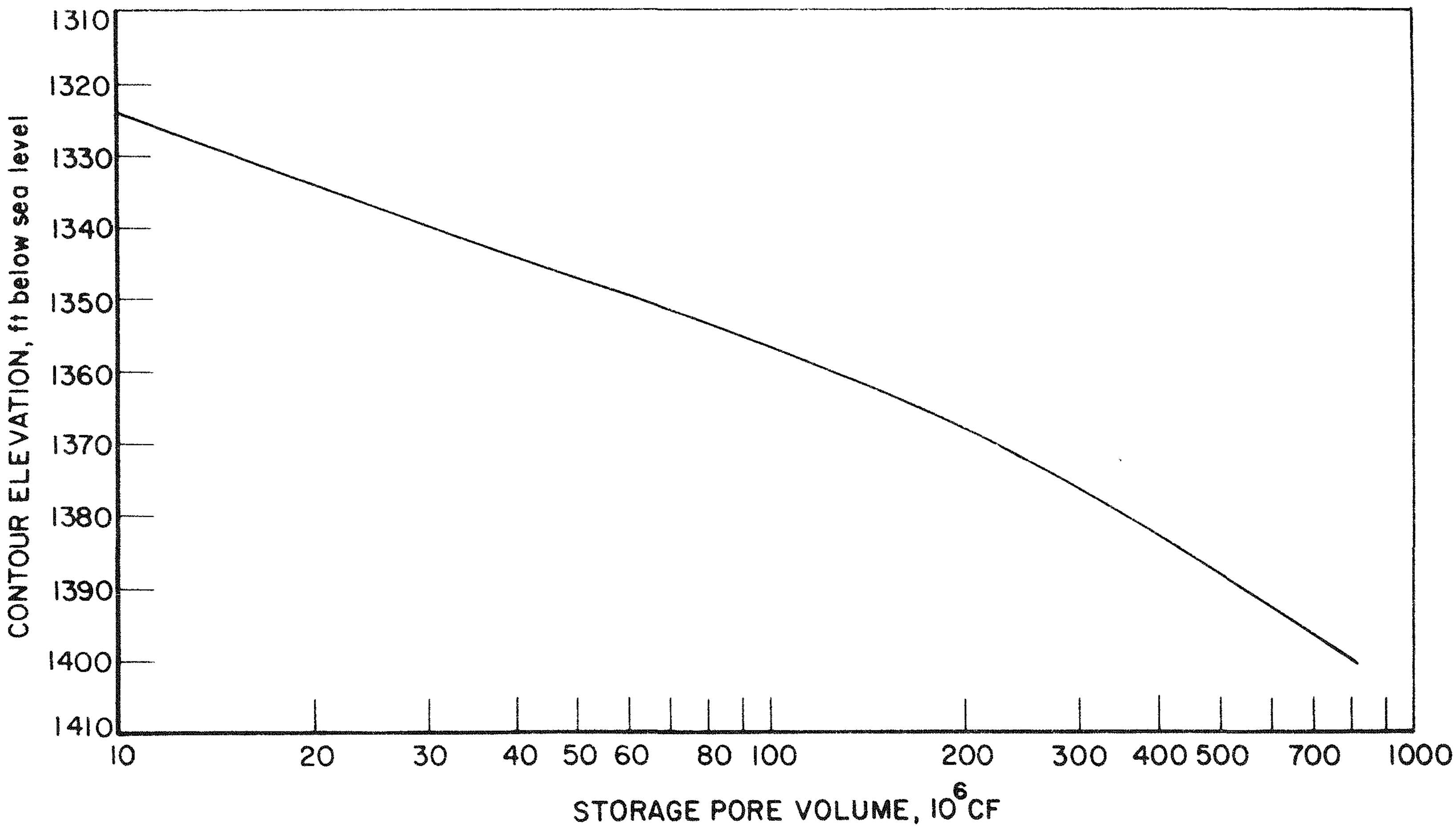

Figure 31. STORAGE VOLUME OF GALESVILLE FORMATION

For hydrogen of viscosity 0.009 cP and natural gas of viscosity 0.012 cP, the readjustment times for r_e = 6000 ft are as follows:

natural gas t_r = 135 hr

hydrogen t_r = 130 hr

These readjustment times of 5 to 6 days are short compared to the months of constant flow in and out in an assumed in-duty cycle. For the assumed schedule, the maximum flow rate is about 39.2 x 10^6 SCF/day. The maximum pressure difference between the mobile gas unit edge and the well bore is then calculated by the steady-state equation (turbulence is neglible):

$$P_1^2 - P_2^2 = \frac{1424\,\mu\ ZTQ}{k\ h} \ln \frac{(r_e)}{(r_w)} \qquad (12)$$

	Hydrogen	Natural Gas	
μ =	0.009	0.012	cP
Z =	1.04	0.95	
T =	532	532	^oR
Q =	39.2	36.1	10^6 CF/day
k =	448	448	ft
h =	65	65	ft'
r_e =	6000	6000	ft
r_w =	0.365	0.365	ft
Assumed P_1 =	900	900	psi
Calculated P_2 =	899	899	psi

The pressure differential is thus very small and neglible for the assured maximum flow rate. The storage reservoir will thus perform essentially the same whether the gas used is natural gas or hydrogen.

Assume the initial void volume in mobile gas unit is 220 x 10^6 CF at a pressure of 840 psi. From Figure 30, this corresponds to a contour elevation of 1370 ft. If the pressure is raised rapidly from 840 psi to 990 psi and held there for 120 days (injection cycle), the water efflux can be calculated, by using q and t_0 from Table 15, as 24.5 x 10^6 CF. The volumetric factor for hydrogen at 840 psi in (Table 15) –

$$F = \left(\frac{14.73}{830}\right)\left(\frac{532}{520}\right)(1.03) = 0.0185 \qquad (13,$$

$$\frac{1}{F} = 53.92\ SCF/ft^3 \qquad (14)$$

The factor for hydrogen at 990 psi is –

$$F = \left(\frac{14.73}{990}\right)\left(\frac{532}{520}\right)(1.24) = 0.0188 \quad (15)$$

$$\frac{1}{F} = 53.17 \text{ SCF/ft}^3 \quad (16)$$

Therefore, working gas above hydrostatic pressure is –

$$\text{Initial} = (220 \times 10^6)(53.9) = 17.86 \times 10^9 \text{ CF}$$

$$\underline{\text{Final} = (245 \times 10^6)(63.2) = 15.50 \times 10^9 \text{ CF}}$$

$$\text{Difference (working gas)} = 8.64 \times 10^9 \text{ CF}$$

In order to achieve a higher fraction of working gas, it may be assumed that during the production phase the gas will be rapidly removed to drop the pressure to about 150 psi below hydrostatic to allow water to flow back to the initial position. The volumetric factor at 690 psi is 45.69 SCF/ft^3, and the final volume is 10.05 billion CF. The difference (or working gas volume) is now 5.45 billion CF. The above procedure can be applied for differing initial void volumes in the mobile gas unit and pressure conditions. For the purposes of this study, we are assuming a total hydrogen (working plus base) volume of 15.5 billion CF and a working gas volume of 5.0 billion CF.

Table 16 summarizes working base-case volumes for hydrogen storage for the four types of storage fields. Also included in Table 16 are the maximum and minimum bottom-hole or field pressures. We have selected three working/base gas ratios for the depleted gas field case to examine the effect of increasing base gas by decreasing the minimum field pressure at the expense of extra horsepower for compression. The first case shown for the depleted gas field (762 psia minimum pressure and 2.87 billion CF working gas volume) represents the pressure range used currently for natural gas service to the field. Working gas volumes of 5.0 and 7.0 billion CF can be achieved by lowering minimum field pressure to 538 and 331 psia, respectively. Because the total field volume (10.25 billion CF) at the unchanged maximum pressure is not changed, increasing the working gas volume decreases the investment required for base gas. However, the lower pressures required to achieve increased working gas volume will mean increased gas compression costs to serve an assumed 750-psia hydrogen pipeline. In a later economic analysis, we examine the trade-off between the installation of extra gas compression equipment and a decrease in investment for base gas to determine the most economically favorable mode of operation of this field. The three cases shown for the mined cavern in Table 16 correspond to caverns cut at increasing depths. The mined cavern field does not exist; therefore, we had to rely on projections for this type of field.

Table 16. SUMMARY OF PRESSURES AND HYDROGEN VOLUMES FOR FOUR STORAGE FACILITIES

Field Type	Bottom-Hole Pressures, psia		Hydrogen Volumes, billion CF		
	Maximum	Minimium	Base	Working	Total
Aquifer	990	690	10.5	5.0	15.5
Depleted Gas Field	1070	762	7.38	2.87	10.25
	1070	538	5.25	5.0	10.25
	1070	331	3.25	7.0	10.25
Salt Cavern	3500	1000	2.28	4.23	6.51
Mined Cavern	1000	226	1.92	6.33	8.25
	1400	325	1.90	5.98	7.89
	1800	417	1.84	5.70	7.54

c. Injection-Withdrawal Cycles

Gas injection and withdrawal cycles vary considerably according to the type of field and the particular market demand of the field operator. A "typical" injection-withdrawal cycle simply does not exist. Injection of gas into a storage field generally corresponds with the summer months, when the demand for gaseous fuel for residential space and water heating is lower. A withdrawal typically corresponds to the winter months, when the demand for gas or space heating is highest. However, it is not uncommon for a gas to be withdrawn from a field to meet a small peak demand during summer months, nor is it unusual for gas to be injected into a particular storage field during winter months. Injection-withdrawal cycles vary considerably from field to field and company to company and also can vary considerably from year to year for a particular field. It is beyond the scope of this study to treat every possible set of injection and withdrawal cycles.

Instead, we chose a fairly simple injection-withdrawal cycle, which approximates a smoothed base-load demand case. In our reference injection-withdrawal case, we assumed 5 months of injection followed by 1 month of no net activity, and 5 months of withdrawal followed by 1 month of net inactivity. Figure 32 is a graphical representation of our standard cycle, shown as a plot of injection or withdrawal flow rate versus time for a 12-month period. The injection and withdrawal cycles are mirror images of one another in Figure 32. During the first month of injection or withdrawal, the hydrogen flow rate into or out of the field builds linearly to a maximum, represented by q_m on

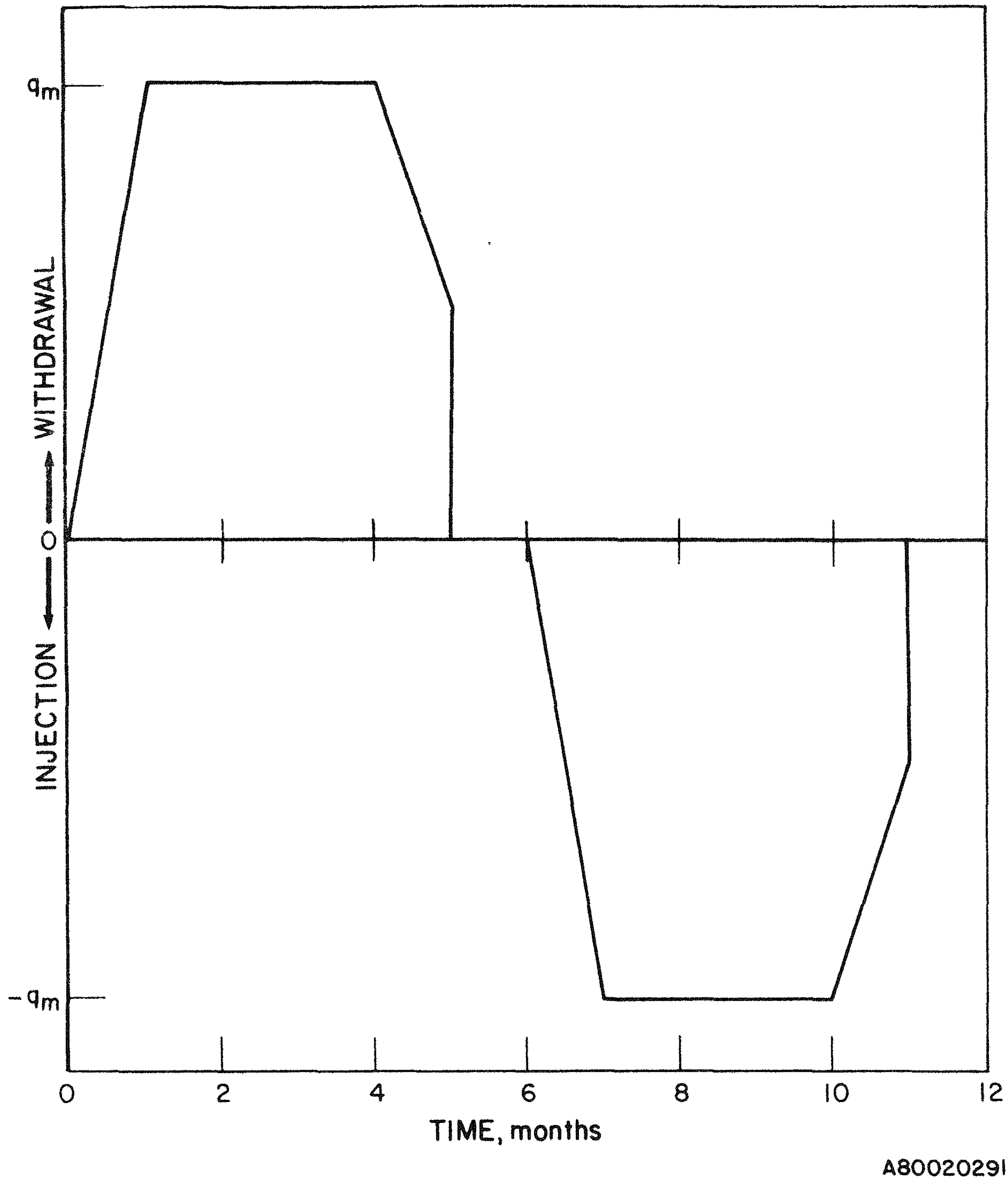

Figure 32. YEARLY INJECTION-WITHDRAWAL CYCLE

Figure 32. The maximum injection or withdrawal rate is maintained for a 3-month period, after which the rate is decreased to half of the maximum over the fifth month. The area under the injection or withdrawal cycle corresponds to one working gas volume for each field.

Note that the cost of service for an underground hydrogen storage facility will be extremely dependent on the assumed injection-withdrawal cycle for a particular application in the market. Wells, compressors, and other aboveground equipment will need to be sized for the maximum flow rates of a particular or injection or withdrawal cycle. Specifically, capability to provide peaking service will require much additional capacity — capacity that will be unused most of the time. It is also feasible to cycle the working gas more than once, as assumed in our standard cycle. Storage facilities designed for peaking service can cycle several working volumes for a 12-month period into and out of the underground reservoir. The cost of service would be decreased by cycling the working gas more than once per season. Therefore, our standard injection-withdrawal cycle and the economic analysis results from it are useful for comparison only. A field-specific economic analysis that takes into account the actual injection-withdrawal history would be required to calculate an accurate cost of service for a particular field designed for a particular hydrogen market.

d. Number of Wells for Hydrogen Service

In underground gas storage operations, fields are designed with a sufficient number of wells to provide the required flow of gas into or out of the field. Well bores in porous-media (depleted fields, aquifers) storage operations are generally large enough that diffusion through the underground porous structure is the limiting factor on the flow of gas into or out of the field. However, in porous media with permeabilities near 1 darcy, the well bore can limit flow. For cavern storage, flow through the well bore is obviously the limiting case. Whether flow through well bore or diffusion through the porous media is the limiting case for gas flow, the volumetric flow of hydrogen from a given well or number of wells should be larger than the corresponding volumetric flow rate of natural gas because of the lower viscosity of hydrogen. (The viscosity of hydrogen is approximately 20% lower than that of natural gas at 1000 psi.)

Given the lower viscosity of hydrogen gas, the number of wells of a given inside diameter designed for natural gas service should be more than sufficient to provide the deliverability specified by our standard injection-withdrawal cycle. For new storage fields designed for hydrogen service, it appears that fewer wells would be required for hydrogen than for natural gas service. Fields designed for natural gas storage that are converted to hydrogen service will have more than enough wells to provide the same volumetric deliverability. It is not safe, however, to assume that the same wells will be appropriate for hydrogen service. We noted in our earlier discussion of hydrogen embrittlement effects that, although well bore casing materials are generally appropriate for hydrogen service at pressures of 1000 to 1200 psi, the materials and welded zones would need to be thoroughly inspected to ensure compatibility with hydrogen service. In our economic analyses, we make the conservative assumption that new wells will need to be drilled. This assumption is conservative because –

a. Well casings, unlike gathering lines, are open for inspection of welds and of the material itself for flaws.

b. Even if the well casing materials are judged unsuitable for hydrogen service at the pressures specified, it is possible to insert tubing liners of appropriate materials without seriously affecting deliverability.

1) Depleted Fields. In order to calculate the number of wells required for a depleted gas field, we used the general "rule of thumb" that wells should be capable of sustaining 125% of the desired gas production rate when 90% of the working gas inventory has been depleted. At the point in the withdrawal season when 90% of the working gas inventory has been depleted, both flow and pressure regimes in the underground porous media should be very well stabilized. Therefore, we used the relationship shown below as Equation 17, proposed by Katz and Coats, for quasi-study-state (stabilized) flow.[32]

$$(P_o^2 - P_w^2) = \bar{Q}\left[\ln R - 0.75\right] + B\bar{Q}^2 \quad (17)$$

where –

$$\bar{Q} = \frac{1424\ T\ Z\ \mu\ Q}{kh}$$

$$B = \frac{1.56 \times 10^{-18}\ \beta\ G\ k^2}{\mu^2\ T\ Z}\left(\frac{1}{r_w}\right)$$

$T = 547^{o}R$ formation temperature

Z = gas compressibility factor

$\mu = 0.009$ cP (hydrogen viscosity)

Q = gas production rate, 1000 CF/day per well

$k = 50$ md (average formation permeability)

$h = 2000$ ft (average formation depth)

$G = 0.07$ (gas gravity)

$r_w = 0.2$ ft (well ID)

$\beta = 1.5 \times 10^8$ (empirically determined turbulence factor, ft^{-1})

$R = r_e/r_w$

r_e = effective drainage radius, ft

P_o = equilibrium field pressure, psia

P_w = flowing sand-face pressure, psia.

Equation 17 expresses the relationship between gas production rate (Q), a turbulence factor (β), and a differential pressure ($P_o^2 - P_w^2$). Equation 17 can be used to calculate the number of wells required directly by transforming gas production rate (Q) and the effective drainage radius (r_e) via Equations 18 and 19 to obtain these variables in terms of the number of wells (n).

$$Q = \frac{Q_T}{n} \tag{18}$$

where –

Q = gas production rate per well

Q_T = total field gas production rate from Figure 32 and Table 17

n = number of wells in the field.

$$r_e = \sqrt{A_T/n\pi} \tag{19}$$

where –

r_e = effective drainage radius

$A_T = 3.5 \times 10^7\ ft^2$ = total field area

$\pi = 3.14$.

Substitution of Equations 18 and 19 into Equation 17 yields an expression that relates $P_O^2 - P_W^2$ in terms of the physical properties of the gas in porous structure, total field

Table 17. MAXIMUM HYDROGEN FLOW RATES DURING INJECTION OR WITHDRAWL

Field	Working Gas Volume, billion CF	Hydrogen Flow Rate (q_m), 10^6/SCF/day
Aquifer	5.0	39.2
Depleted Gas Field	2.87	22.5
	5.0	39.2
	7.0	54.9
Salt Cavern	4.23	33.2
Mined Cavern	6.32	49.6
	5.98	46.9
	5.70	44.7

flow rate, and the number of wells in the field. By making these substitutions and inserting some of the physical constants into Equation 17, Equation 20 is obtained.

$$(P_o{}^2 - P_w{}^2) = \left(3.505\, Z\, \frac{Q_T}{n}\right) \ln \frac{A_r/n}{r_w} - 0.75 + 4.49 \times 10^{-6} \left(3.505\, Z\, \frac{Q_T}{n}\right)^2 \qquad (20)$$

Equation 20 was solved to yield the number of wells required for the depleted gas field by the procedure described below.

1. The hydrogen flow rate required at 90% of depletion of working gas is calculated from the point on Figure 32 where 90% of the area is enclosed. (The vertical scale in Figure 32 is set by the value of q_m taken from Table 17.) 125% of the calculated hydrogen flow rate is substituted into Q_T in Equation 20.

2. The equilibrium field pressure (P_o) and compressibility (Z) are determined from a plot of P_o/Z versus gas inventory prepared for the depleted field in hydrogen service. The equilibrium field pressure and compressibility factor are substituted into Equation 20.

3. Based on the operating experience of our participating industrial company, a pressure drop ($P_o - P_w$) of 100 psi is assumed, and a value for P_w is substituted into Equation 20.

4. The number of wells required for the field (n) is calculated by trial and error for each case for the depleted field.

To the number of production wells calculated by our procedure, we add a total of three observation wells for each case to determine a total number of wells. The results of these calculations for each assumed hydrogen working gas inventory are presented in Table 18.

Table 18. NUMBER OF WELLS REQUIRED FOR THE DEPLETED GAS FIELD

Case	Working Gas Inventory, billion CF	Production Wells	Observation Wells	Total Wells
I	2.87	5	3	8
II	5.0	11	3	14
III	7.0	22	3	25

2) Aquifers. The aquifer was not chosen for the detailed analysis in Task 4. Therefore, our estimation of the number of wells for this storage facility was not as detailed as the estimation procedure used for the depleted gas field. The single-well performance equation used in the FPC filing for the aquifer storage field, shown as Equation 21, was modified to take into the account the physical properties of hydrogen.

$$P_1^2 - P_2^2 = \frac{142\mu\, zTQ\ln(r_1/r_2)}{hk} + \frac{\left(3.161 \times 10^{12}\right) BQ^2 zTG\left(\frac{1}{r_2} - \frac{1}{r_1}\right)}{h^2} \qquad (21)$$

where –

P_1 = pressure in reservoir, psia

P_2 = flowing well pressure, psia

μ = gas viscosity, cP = 0.009

z = gas compressibility factor = 1.034

T = temperature, $^{\circ}$R = 532

Q = gas well flow rate

h = effective well penetration, ft = 40

k = sand permeability, md = 448

r_1 = radius of reservoir to P_1, ft = 330

r_2 = radius of well to P_2, ft = 0.328

G = gas gravity, 0.0676

B = turbulence factor = 1.0×10^7.

Equation 21 is similar to Equation 17, used for the depleted gas field case, but steady-state operation is assumed.

The results of the calculations using Equation 21 are presented in Table 19. The results indicate the expected hydrogen flow rate from a single well for various pressure levels in the aquifer. We used the minimum flow calculated (at the pressure corresponding to hydrostatic) to yield a minimum hydrogen flow of 6.125 X 10^6 SCF/day per well. We then simply divided the maximum hydrogen flow required from the aquifer field (q_m) from Table 17, which is 39.2 X 10^6 SCF/day, by the calculated hydrogen flow per well to yield just less than eight wells for our assumed deliverability profile from the aquifer. Because the wells calculated for hydrogen service are fewer than those required for natural gas service, the well spacing (r_1 in Equation 21) would be increased. But this effect would be relatively minor, and eight is a conservative number of wells for the aquifer converted to hydrogen service. Nine observations wells, which are required for natural gas service, also would be appropriate for hydrogen service, yielding a total of 17 wells for the aquifer storage facility.

Table 19. HYDROGEN FLOW RATES CALCULATED FROM EQUATION 21

P_1, psia	P_2, psia	Q (methane), 1000 CF/day	Q (hydrogen), 1000 CF/day
940	930	5725	6900
900	890	5485	6600
870	860	5300	6385
840	830	5125	6165

3) Cavern Storage. Because a single well is required for both the washed-salt-cavern and the mined-cavern storage fields, this case is trivial. A single well also would be required for hydrogen service.

e. Hydrogen Compression Equipment

A detailed analysis of the hydrogen compression equipment required for the three working gas inventory cases for the depleted field was performed. As a basis for this analysis, we assumed that the storage field serviced a 750-psig hydrogen transmission pipeline. In order to attain the most reliable equipment specifications and cost estimates for hydrogen compression equipment, we enlisted the aid of a manufacturer (Ingersoll-Rand Co.).

The manufacturer had to be supplied with compressor suction pressures and gas flow rates as functions of time for the three cases to be investigated for the depleted gas field. Starting with the flowing sand-face pressure, we calculated the pressure drop due to friction in the well bore and assumed a 5-psi pressure drop in the gathering system to yield the suction pressure for the compressor. The results of this analysis are presented in Figure 33, which is a plot of total field flow rate and compressor suction pressure versus time for the withdrawal cycle for the depleted gas field. All three cases are indicated in Figure 33. Based on the results of a recent Exxon study,[16] we also specified electric motors as the prime movers for the compression equipment.

The equipment specifications and machine costs supplied by the manufacturer for the three cases in question are listed below.[13]

- Case I

  Q = 23 x 10^6 SCF/day
  Governing Case: injection
  Machines and Cost: two (2) 5.5 and 5.5 x 9-2HSE-1 at $264,413
  BHP Required: 560
  Motor: (2) 350-hp, 514 rpm induction, 460 V, 60 cycle, 3 phase
  Motor Efficiency at Full Load = 91%

- Case II

  Q = 40 x 10^6 SCF/day
  Governing Case: withdrawal
  Machines and Cost: three (3) 6.5 and 6.5 x 0-2HSE-1 at $365,933
  BHP Required: 910
  Motor: (3) 350 hp, 514 rpm induction, 460 V, 60 cycle, 3 phase
  Motor Efficiency at Full Load = 91%

- Case III

  Q = 55 x 10^6 SCF/day
  Governing Case: withdrawal
  Machines and Cost: one (1) 4-11.4 x 11-4HHE-VC-1 at $724,660
  BHP Required: 3036
  Motor: (1) 3500 hp, 2300 V, 514 rpm sync.
  Motor Efficiency at Full Load = 97%.

Total capital costs for compression equipment for the depleted field (all three cases) are summarized in Table 20. The machine cost listed includes the cost of the Ingersoll-Rand balanced-opposed reciprocating compressors, induction driving motors, standard lubricated cylinders, special high-velocity valves (to match the low viscosity of hydrogen), valve unloaders and pulsation bottles for each cylinder, explosion-proof electrical system, and all electrical couplings. The installation costs listed in Table 20 are for additional costs (to turnkey status) based on an estimated $500/horsepower installed. Controls costs listed in Table 20 are for instrumentation and control panels, one $10,000 package assumed per machine.

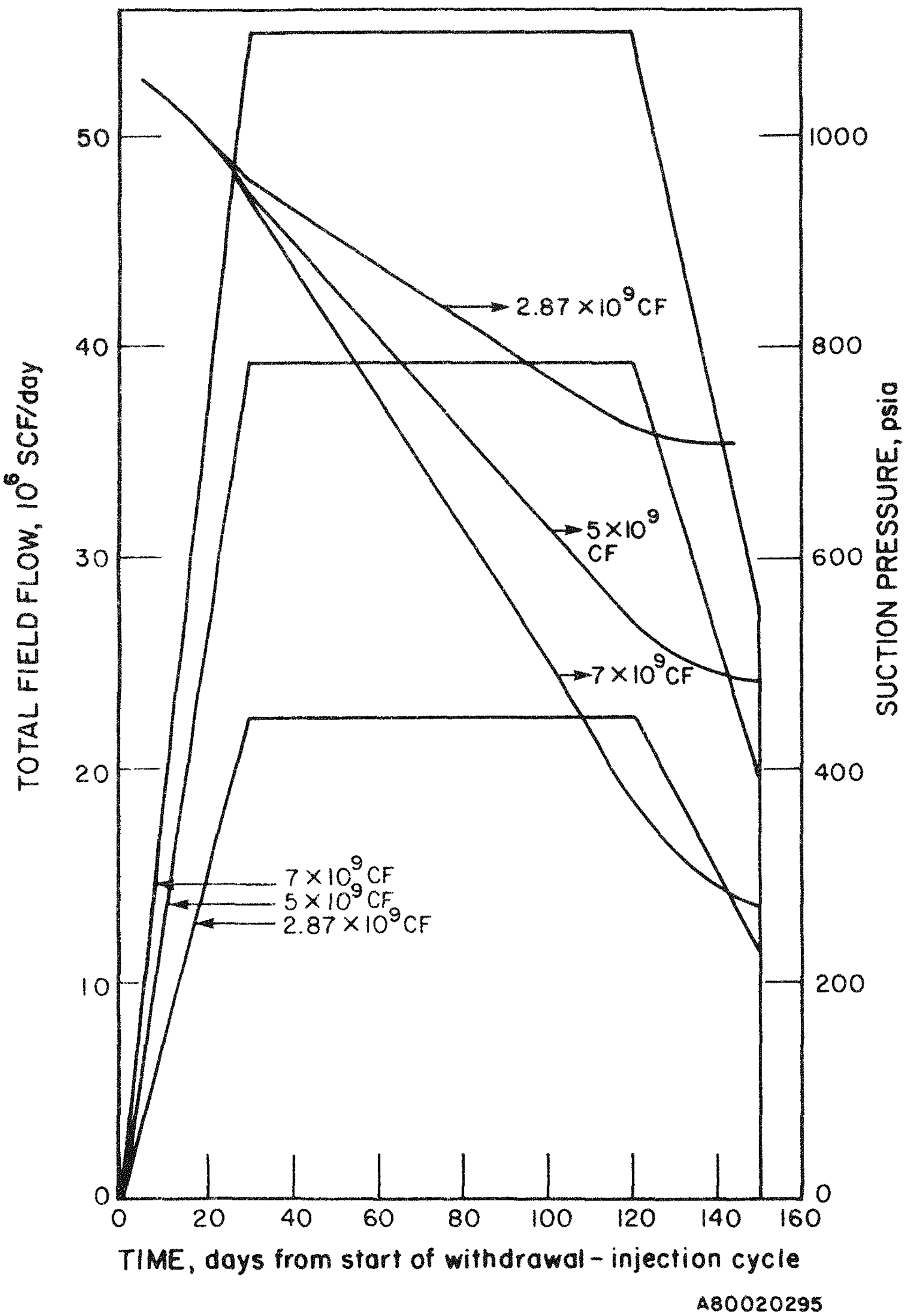

Figure 33. COMPRESSOR SUCTION PRESSURE AND TOTAL FIELD FLOW VS. TIME FOR THE WITHDRAWAL CYCLE FOR THE DEPLETED GAS FIELD

Table 20. COMPRESSOR COSTS FOR THE DEPLETED FIELD

Case	Machine Cost	Installation Cost	Controls Cost	Total
	$1000			
I	264	350	20	634
II	336	525	30	921
III	725	1750	10	2485

Table 21 summarizes the annual operating cost for hydrogen compression for the depleted field, all three cases, for power costs from 2¢ to 5¢ per kilowatt-hour. The annual power consumption listed in Table 21 was calculated based on the suction/pipeline pressure ratio and gas flow rate indicated in Figure 33. Additional annual costs for maintenance were not supplied by the manufacturer and were estimated from existing data on natural gas compression units.

Table 21. ANNUAL OPERATING COSTS FOR HYDROGEN COMPRESSION FOR THE DEPLETED FIELD

Case	10^6 kWhr/yr	Annual Operating Cost for Power Costs of 2¢/kWhr	3¢/kWhr	4¢/kWhr	5¢/kWhr
		$1000			
I	0.909	18.2	27.3	36.4	45.5
II	1.65	33.0	49.5	66.0	82.6
III	4.91	98.2	147.4	196.5	245.6

The costs for hydrogen compression for the three cases (different working gas inventories) provide the basis for an economic analysis of the trade-off between smaller based gas inventory and increased compression costs. A detailed analysis was performed only for the depleted-field case. Hydrogen compression costs for the other three storage field types were estimated based on the figures calculated for the depleted-field cases.

f. Gathering Systems

The design of the gathering system for an underground gas storage field is strongly dependent on the field size and shape, the number of wells required, and the desired capacity for deliverability of that field. Cavern storage fields (washed salt or mined) generally have small areas and a small number of wells. The gathering systems, therefore, are not extensive, and few differences in design are expected for hydrogen storage operations as opposed to natural gas operations. Porous-media storage fields (depleted field or aquifer), on the other hand, generally encompass large areas, have multiple wells, and require extensive gathering systems. As noted earlier, the number of wells required for a given field for hydrogen storage will be lower than the number of wells for an equivalent volumetric output of natural gas. However, the fewer wells will occupy the same total field area for both hydrogen and natural gas operations. We do not expect the total length of the gathering system for hydrogen service to be significantly less than that for natural gas service, even though the number of wells is smaller. The only portions of the gathering system that could be deleted for hydrogen service would be some of the small lateral lines running to individual wells. It is beyond the scope of this program to completely redesign the gathering system for any field. We did perform, however, a qualitative analysis for the field (depleted gas field) selected in Task 4 for a detailed analysis. Although the pipe materials used in present natural gas gathering lines probably are compatible with hydrogen from the standpoint of hydrogen embrittlement, we noted earlier in the embrittlement section that the inspection of welds and section size changes would be required before any existing gathering system could be converted to hydrogen. Because a thorough inspection of an existing (in-ground) gathering system probably would be very expensive, we will assume that a new gathering system would be laid for converted fields as well as well for newly designed fields for hydrogen service.

The gathering system currently used in the depleted gas field for natural gas storage consists of 4-in. gathering lines running to individual wells, 8-in. and 16-in. intermediate gathering lines, and 20-in. mains. This system is designed for a maximum pressure drop across the gathering system of 5 psi for the maximum gas flow rate. For our hydrogen storage option with the greatest hydrogen deliverability (Case III, with 7 billion CF working gas inventory and a maximum hydrogen flow rate of 54.9 million SCF/day), we calculate that 4-in., Schedule-80 pipe would have less than a 2-psi pressure drop for a 600-ft gathering line to an individual well for the maximum flow. Gathering mains could be constructed of 8-in., Schedule-80 pipe up to 2000 ft long for the maximum flow rate with less than a 5-psi pressure drop to the compressor. Therefore, the gathering field design for a hydrogen storage system should be slightly shorter and constructed of smaller diameter pipe. However, the probability that a slightly more expensive pipe material would be required and that more expensive construction and testing procedures would be required are compensating factors that would tend to offset any cost decrease due to shorter and smaller diameter lines. We therefore use the same cost for pipe that was quoted to us for the original natural gas storage field. This should be a slightly conservative, but safe, estimate.

g. Other Equipment

The following pieces of aboveground equipment will need to be changed when a natural gas storage facility is converted to hydrogen service. These changes are dictated by technical considerations, but are not expected to signifcantly affect the cost of service for hydrogen service. As noted in the section on hydrogen safety considerations, several equipment items will have to be changed or modified. All wiring (including the cathodic protection system) will have to be revamped to make it explosion-proof to fit safety codes. Leak detectors will have to be recalibrated and their flame arrestors changed to account for the different properties of hydrogen gas. Flow-metering equipment will need to be either changed or recalibrated to allow hydrogen service. All materials of construction (including sealing and lubricating materials) will have to be thoroughly checked for their compatibility with hydrogen gas. In addition, the dehydration equipment common in natural gas service may require modification. The reduction in water content of withdrawal gas to 7 pounds of water vapor per million SCF of withdrawal gas to prevent condensation in transmission and/or distribution lines will remain the same. However, the methanol injection system commonly used in natural gas facilities to prevent hydrate formation at or just beyond the wellhead will not be required for hydrogen service, because hydrogen will not form stable hydrates. Note, however, that fields that have been converted from natural gas service or depleted gas fields may require some methanol injection due to residual natural gas contents in the early years of operation.

h. Conclusions

From an economic viewpoint, it appears that there will be little difference between the conversion of an existing natural gas storage facility and the development of a new field specifically for hydrogen service. The major capital cost items (wells, gas compression systems, and gathering systems) probably will have to be replaced in the conversion of an existing natural gas facility to hydrogen service. From a technical viewpoint, the same general type of system and many of the minor parts of the system will be applicable to both natural gas and hydrogen service. There appear to be no major gaps in either technology or operational procedure for underground hydrogen storage (except, perhaps, for unspecified materials for very-high-pressure storage fields).

2. Economics of Hydrogen Storage Field

The hydrogen storage economic analysis was carried out by using the methodology developed for natural gas storage in Section III-A. Each type of field was analyzed again with base-case values that reflect reasonable assumptions for hydrogen storage. These base-case values then were parametrically varied as they were for natural gas storage. The depleted field was singled out for further detailed study. This involved examining the trade-off between obtaining more throughput for the field at the expense of more compression and wells. By keeping the field volume constant but increasing the amount of gas withdrawn per cycle, the amount of base gas decreases. In addition, we examined the possible economic effects of retrofitting this reservoir for hydrogen service instead of developing a totally new reservoir. The following sections describe the assumptions made to model each type of reservoir, the base-case cost of service, and how the cost-of-service sensitivity for each parameter for hydrogen storage compares with that for natural gas storage. The base-case assumptions for hydrogen service for the four types of reservoirs are listed in Table 22.

Table 22. BASE-CASE ECONOMICS OF STORING HYDROGEN IN FOUR TYPES OF RESERVOIRS

Item	Salt Cavern	Excavated Cavern	Aquifer	Depleted Field
Erected Plant Cost, $\$10^3$	16,400	50,000	31,900	6,660
Annual Throughput, 10^{12} Btu	1.44	2.03	1.7	0.976
Cost of Base Gas $\$/10^6$ Btu	6.00	6.00	6.00	6.00
Annual Operating Cost, $\$10^3$	350	425	1025	230
Construction Time, yr	3	3	3	3
Cost of Debt, %	10	10	10	10
Cost of Equity, %	15	15	15	15
Fraction Debt Financed	0.6	0.6	0.6	0.6
Lifetime for Economics, yr	27	27	27	27
Cost of Service, $\$/10^6$ Btu	3.03	5.27	6.59	4.47
Variation in Cost of Service, $\$/10^6$ Btu	(2.44-4.27)	(3.23-7.51)	(4.18-10.03)	(2.76-8.89)

a. Salt Cavern

The base-case plant costs and operating costs for hydrogen storage were assumed to be the same as those for natural gas storage. This assumption is based on having the same number of wells for hydrogen storage as for natural gas storage. The salt cavern was assumed to be operating within a 1000 to 3500-psi pressure range per annual cycle. Based on this assumption, the amount of throughput is 4.42 billion CF, or 1.438 X 10^{12} Btu. By using the same financial values as for the natural gas base case and choosing to store \$6.00/10^6 Btu gas, the base-case cost of service is \$3.03/10^6 Btu (1978 dollars).

Figure 34 illustrates the sensitivity of this base-case cost of service to parametric variation. The different parameters have the same relative degree of sensitivity as they did for natural gas storage in salt caverns; that is, the cost of service is relatively insensitive to the base gas cost. The major contribution to the high cost of service for hydrogen storage is the smaller amount (by volume) of gas that can be stored for the operating pressure range allowed in the reservoir coupled with the smaller throughput per cycle of the reservoir. The base-gas cost for hydrogen storage is \$4.65/10^6 Btu, or 28% of the plant cost. The base-gas cost for natural gas is \$0.68/10^6 Btu, or only 4% of the plant cost. (The base-gas cost and plant cost are treated similarly but separately in the analysis.) The throughput of gas is only 1.44 X 10^{12} Btu/yr for hydrogen, compared with 6.2 X 10^{12} Btu/yr for natural gas. This large ratio almost completely accounts for the \$3.00/10^6 Btu cost of service for the \$6.00/10^6 Btu gas.

This analysis implies therefore that, for salt cavern, the high plant cost combined with the smaller amount of energy that can be stored makes the actual price of the gas to be stored a small influence on cost of service. To visualize the effect of zero base-gas cost (by using an inert gas that does not mix or by operating the reservoir in a water-compensated mode), just extend the base-gas cost line to −100%. The cost of service is still quite high. (This negative extrapolation works only for plant costs and base-gas costs.)

b. Aquifer Storage

Unlike the salt-cavern storage case, the porous-field storage does require some changes in the physical plant. The primary change is in the fewer number of wells required for hydrogen service, as discussed in Section III-B-1-d). Adjustments therefore were made for different compressor costs and operating costs. The base-gas cost to plant cost ratio is 65% for natural gas and 67% for hydrogen gas, so that the cost-of-service sensitivity plot, Figure 35, is almost the same as that for natural gas (Figure 25). The base cost of service is higher for hydrogen storage because of the smaller Btu

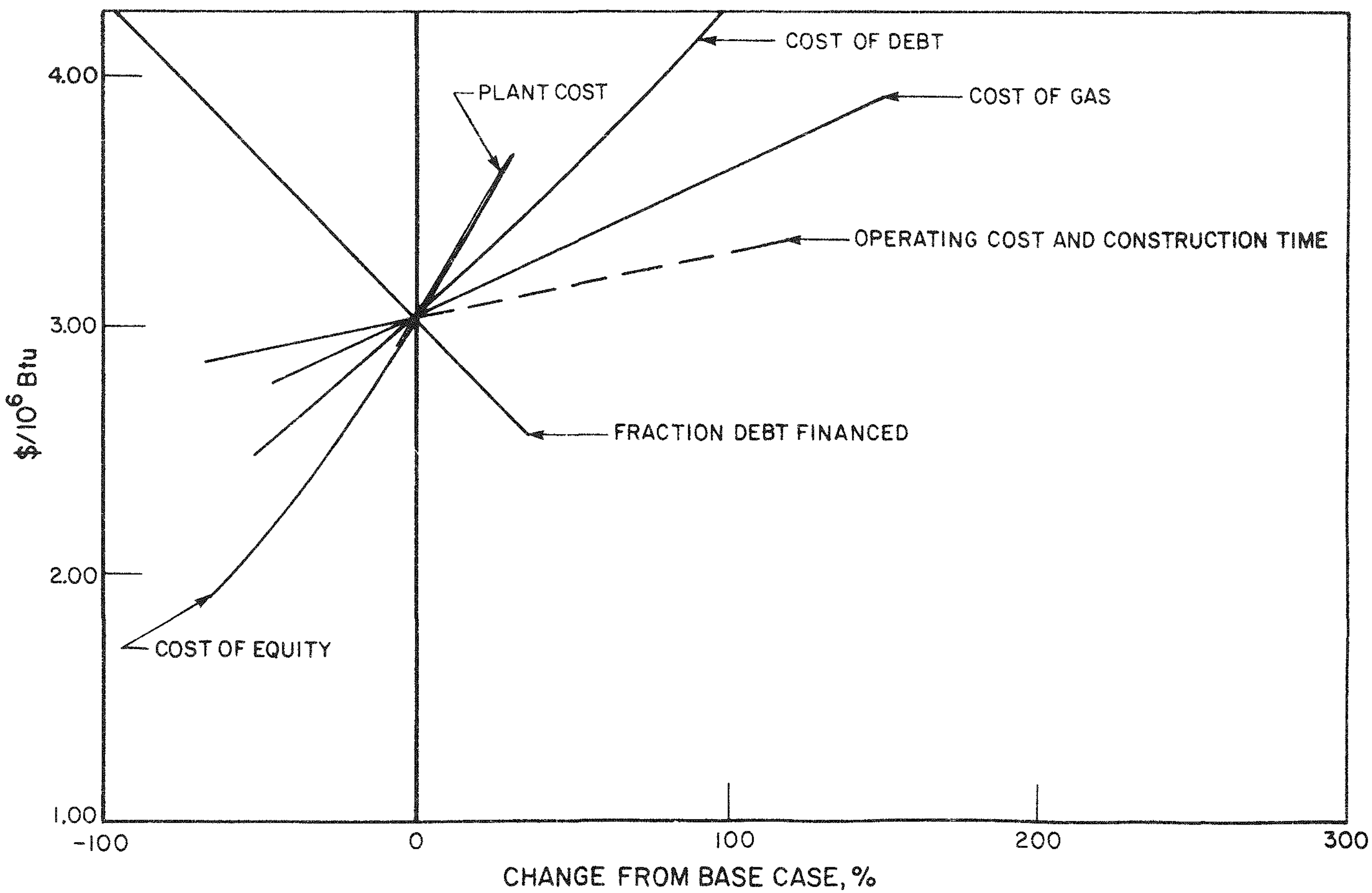

Figure 34. COST-OF-SERVICE SENSITIVITY PLOT FOR STORING HYDROGEN IN A SALT-CAVERN RESERVOIR

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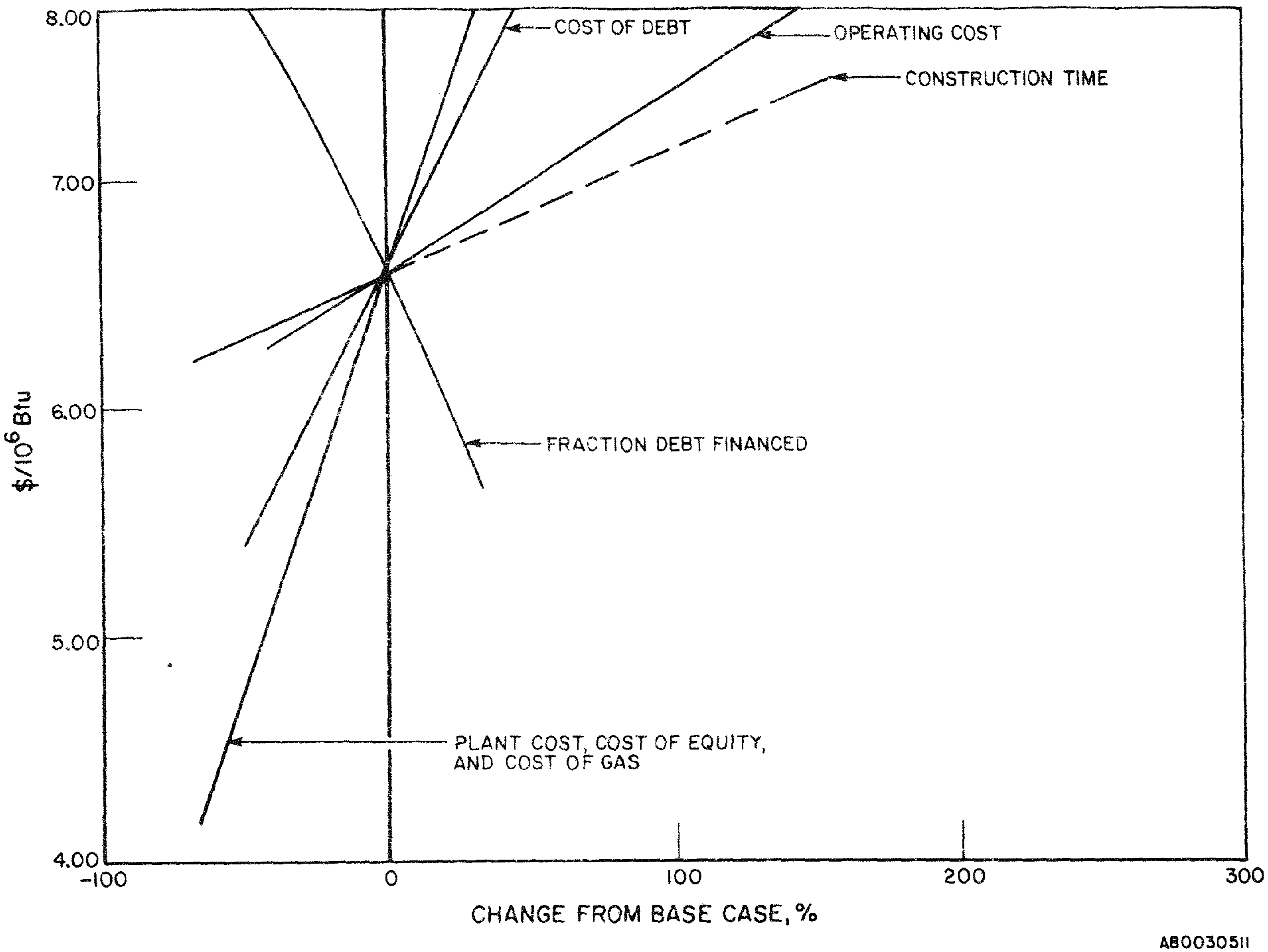

Figure 35. COST-OF-SERVICE SENSITIVITY PLOT FOR STORING HYDROGEN IN AN AQUIFER RESERVOIR

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throughput per year. Unlike the excavated cavern costs, the cost of service is sensitive to the cost of the base gas. Eliminating the base-gas cost reduces the cost of service to 60% of the base-case costs.

c. Excavated Cavern

The excavated cavern illustrates in an even more severe manner the effect of large development costs and lower throughput per cycle. Assuming that the plant costs, operating costs, and methods of financing are essentially the same for hydrogen service as for natural gas service, Figure 36 illustrates the sensitivity of cost of service. The base-case cost of service is $5.27/10^6 Btu for gas that costs $6.00/10^6 Btu. Again, the cost of service is practically insensitive to the cost of the base case.

d. Depleted Field

The depleted field was analyzed in somewhat more detail than the other three types of reservoirs. In particular, three different cases were investigated. The parameters for these cases are listed in Table 23. The distinction made in Table 23 is that from Case I through Case III the throughput per year increases, the base gas volume decreases, and the plant cost increases. By examining the cost of service, we observe that the increased well and compression costs (showing up as increased plant cost) are more than compensated for by the increased throughput and decreased base gas. Case III was singled out for the sensitivity plot, as shown in Figure 37.

Table 23. EFFECT OF INCREASING THROUGHPUT ON COST OF STORING HYDROGEN IN A DEPLETED-FIELD RESERVOIR

Item	Case I	Case II	Case III
Plant Cost, $\$10^3$	6660	7600	10,700
Throughput, 10^{12} Btu	0.976	1.700	2.380
Base Gas Cost, $\$10^3$	15,050	10,700	6630
Cost of Service, $\$/10^6$ Btu	4.47	2.21	1.51

As noted in the methodology, base gas was assumed to be financed along with the plant. The base-gas cost should be of growing concern to potential field builders; as its cost or value increases for any type of gas, the ability to pay for it in the first year of operation without financing becomes more difficult. With base-gas costs of about $5 million to $15 million, financing its purchase becomes a good assumption. Table 23 represents two cases (I and III depleted field) in which base gas is paid for only in the first year the plant is financed. As expected, the cost of service is reduced.

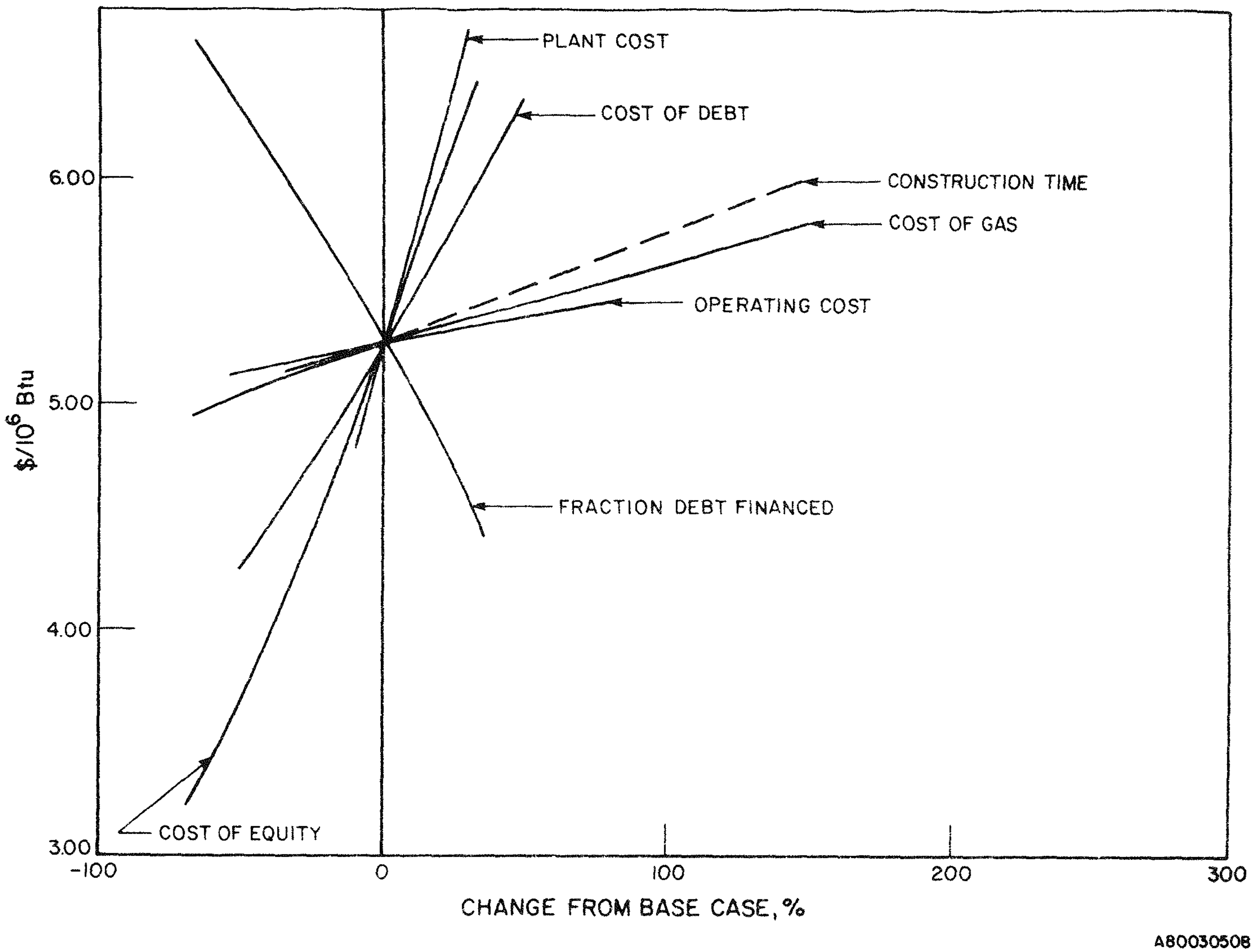

Figure 36. COST-OF-SERVICE SENSITIVITY PLOT FOR STORING HYDROGEN IN AN EXCAVATED-CAVERN RESERVOIR

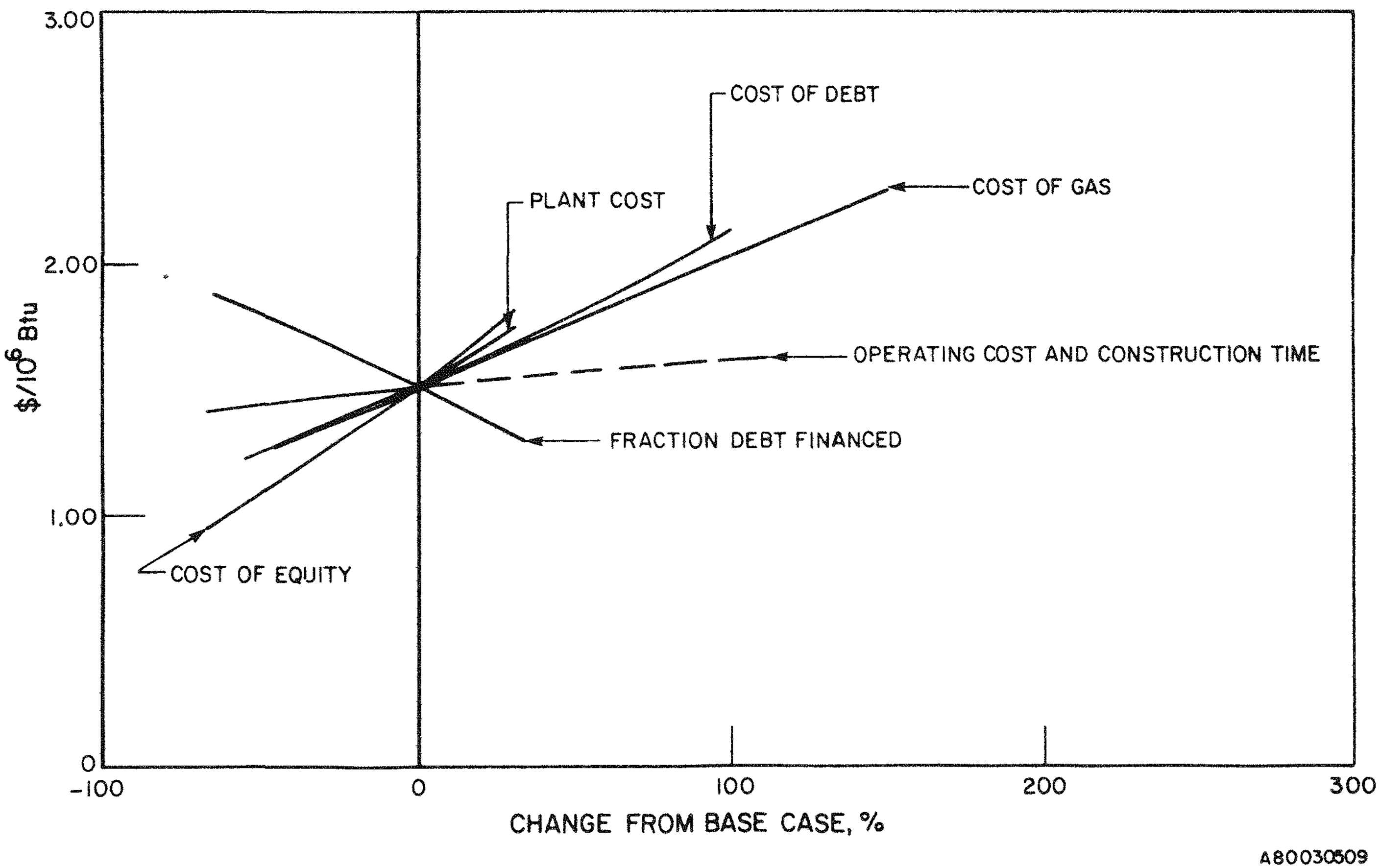

Figure 37. COST-OF-SERVICE SENSITIVITY PLOT FOR STORING HYDROGEN IN A DEPLETED-FIELD RESERVOIR – CASE III

e. Retrofit of Depleted Field

Test cases were run for retrofitting the depleted field for hydrogen service rather than constructing a new field. Retrofitting, in terms of plant economics, changes the required plant capital cost for construction. The sensitivity of service cost to plant construction cost was analyzed for changes in several costs in the parametric analysis. They need only be treated here as special cases. The retrofit test cases provided for eliminating the land cost, well cost, line cost, or combinations of these parameters. For the Case I depleted field, the resulting costs of service ranged from $\$4.47/10^6$ Btu for the original base case down to $\$3.35/10^6$ Btu stored for the case less land, wells, and line cost. The latter case, though of questionable possibility, only includes $\$1.85/10^6$ Btu for the plant and \$15 million for the base gas, the major financed item.

For the Case II field retrofit, the range of cost of service for the tested cases was $\$2.22/10^6$ Btu stored through $\$1.72/10^6$ Btu for the case less land and wells. For the Case III field retrofit, the range was $\$0.95/10^6$ Btu for the case less land, wells, and lines through $\$1.51/10^6$ Btu for the original base case.

All of the above is shown in Table 24.

Table 24. RETROFIT OF DEPLETED FIELD FOR HYDROGEN STORAGE

BASE CASE	CASE I	CASE II	CASE III
Operating Cost, $\$10^3$	230	265	285
Base Gas Cost, $\$10^3$	15,050	10,070	6630
Throughput 10^{12} Btu	0.976	1.7	2.38
Plant Cost, $\$/10^3$	6600	7600	10,700
Gas Cost, $\$/10^6$ Btu	6.00	6.00	6.00
Cost of Service, $\$/10^6$ Btu	4.47	2.21	1.51
RETROFIT CASE			
Plan Cost	1850	3200	3650
(Assuming Land, Wells, Lines Costs = 0)			
Cost of Service, $\$/10^6$ Btu	3.35	1.72	0.95

IV. CONCLUSIONS AND DISCUSSION

This study was designed to determine which of the following conclusions about underground hydrogen storage is most accurate based on technical and economic findings:

1. "Current underground gas storage practice can be used to economically and safely store hydrogen in widely available reservoirs."
2. "Further research is needed to determine whether hydrogen can be stored underground safely and economically."
3. "Underground storage of hydrogen is unsafe or not economic at this time."

We consider the first conclusion to be the most appropriate. "Current underground gas storage practice can be used to economically and safely store hydrogen in widely available reservoirs."

We found no technical constraints that prohibit the storage of hydrogen in underground reservoirs. There are, however, technical questions that must be addressed by appropriate R&D programs for some underground storage applications. Economic feasibility is a more complex issue. Under the best of circumstances, the development of an underground reservoir for natural gas storage requires many years for a utility. Site selection is only one of a number of decisions in a complicated process that must consider ultimate volume and throughput, pricing, FERC filings, and corporate decisions dealing with the entire company, not just the storage operation. There is no reason to believe that this process will be less involved for hydrogen storage than for natural gas storage. In particular, the most favorable storage location may not be near the source of hydrogen or near the end user. Some compromises must be made – trade-offs between convenience, cost of service, and time. Certainly underground storage of hydrogen on a large scale is more economical than aboveground alternatives, for which storage costs of about $50/10^6 Btu have been estimated (1972 $).[28] It should be clearly understood that the cost of storing gas (either hydrogen or natural gas) is very site-specific and that a range of costs is possible for each type of storage. Our economic analyses indicate that, for a given type of reservoir in a given location, the ratio of the cost of storage to the cost of the gas itself is very nearly the same whether the gas is hydrogen or natural gas. In effect, we expect the cost of storing hydrogen to be approximately equal to the cost of storing equally expensive natural gas. The following sections summarize technical and economic conclusions and list future R&D needs.

A. Technical Results

We conclude that although all types of reservoirs cannot be used at all times for any type of service, there are no technical constraints that prohibit the storage of hydrogen in underground reservoirs. Some pressure limitations and constraints on how the fields are cycled make some fields more attractive than others for storage. However, as we have discussed previously, no mode of operation is prohibited for safety or environmental reasons. Table 25 summarizes the various technical conclusions of this project and gives a relative evaluation of their economic impact. The strongest technical constraint is hydrogen embrittlement, which limits the reservoir pressures to 1200 psi or less with commonly used materials of construction. Deep caverns cannot be operated economically with this pressure constraint. However, shallow salt formations can be operated in a water-compensated mode, and this type of operation may be the most attractive alternative, as discussed in the next section.

B. Results of Economic Analysis

Costs of service ($\$/10^6$ Btu) for the storage of both hydrogen and natural gas were calculated for four specific reservoirs that are examples of four different types of storage (depleted field, aquifer, washed salt cavern, and excavated cavern). For each type of storage, a base case was developed, and the sensitivity of cost of service to various technical and economic parameters was examined. Figure 38 is a graphical summary of the base-case costs of service calculated for both hydrogen and natural gas storage. Our objective in preparing base cases for natural gas service was to test our model against actual practice, and somewhat different base-gas costs were assumed for each case. Therefore, the four natural gas base cases shown in Figure 38 are not directly comparable. The hydrogen base cases can be compared, either with one another or with their respective natural gas base cases.

The contribution of operation cost, cost of base gas, and installed physical plant cost to the overall cost of service also is indicated in Figure 38. In all four types of fields, the plant and annual operating costs are very similar for either natural gas or hydrogen storage. However, because of the different volumetric heating values and compressibilities of natural gas and hydrogen, the total Btu throughput for hydrogen service is a factor of two to four lower than that for natural gas service. An implicit assumption in this study is that the cost of service for hydrogen is calculated for a given reservoir with a given pore space volume. No attempt was made to compare the cost of hydrogen service based on an equivalent BTU basis to natural gas service. Therefore, the

Table 25. SUMMARY OF PROJECT FINDINGS

Conclusion	Technical Effect	Economic Effect
Safety —		
No change in compressor station design.	None.	None.
Compliance with Class 1, Group B Standards of National Electrical Code[42]	More stringent for natural gas; applicability must be determined.	Slight to none.
Hydrogen-type leak detectors.	Different than those for natural gas, but already exist.	Slight to none.
No change in safety relief devices.	None.	None.
Gasket and seal materials for hydrogen.	Already exist.	None.
Environmental Effects —		
Free hydrogen not toxic.	None.	None.
Combustion product is water.	None.	None.
Noise from damaged wellhead could be greater than for natural gas.	More remote location may be required.	None.
Embrittlement —		
Use of existing materials precludes pressures in excess of 1200 psi.	High-pressure reservoirs are restricted.	Maximum use sometimes restricted.
Weldments and flaws most sensitive even below 1200 psi.	Complete inspection or replacement of surface equipment.	Adds significantly to cost of retrofitting field.
Special compressor design and materials.	Design exists, must be replaced.	Hydrogen compressors cost only slightly more than methane compressor, but must be used.
Chemical Reactions —		
No reactions have been identified that will consume substantial hydrogen or produce unwanted by-products.	The possible reactions for each field must be determined in detail.	Unknown.
Purity Requirements —		
For supplement to natural gas, none.	May use natural gas base gas.	Reduces cost of service to use natural gas base gas significantly.
For chemical feedstock, variable.	Must use new reservoir or clean up the delivered gas.	Variable.
Mixing —		
Difficult to control in low-porosity, low-permeability reservoirs.	More sophisticated reservoir model required.	
Easy to control in high-permeability, high-porosity reservoirs.	Moderately careful injection and withdrawal schemes; some cleanup may be required.	Most economic mode; allows use of inert base.
Mixing may be desirable.	Deliverable monitoring to determine pricing.	Requires complicated pricing scheme.
Leakage —		
Frequency and magnitude of loss and/or leakage rates will not exceed those for natural gas storage.	None.	None.

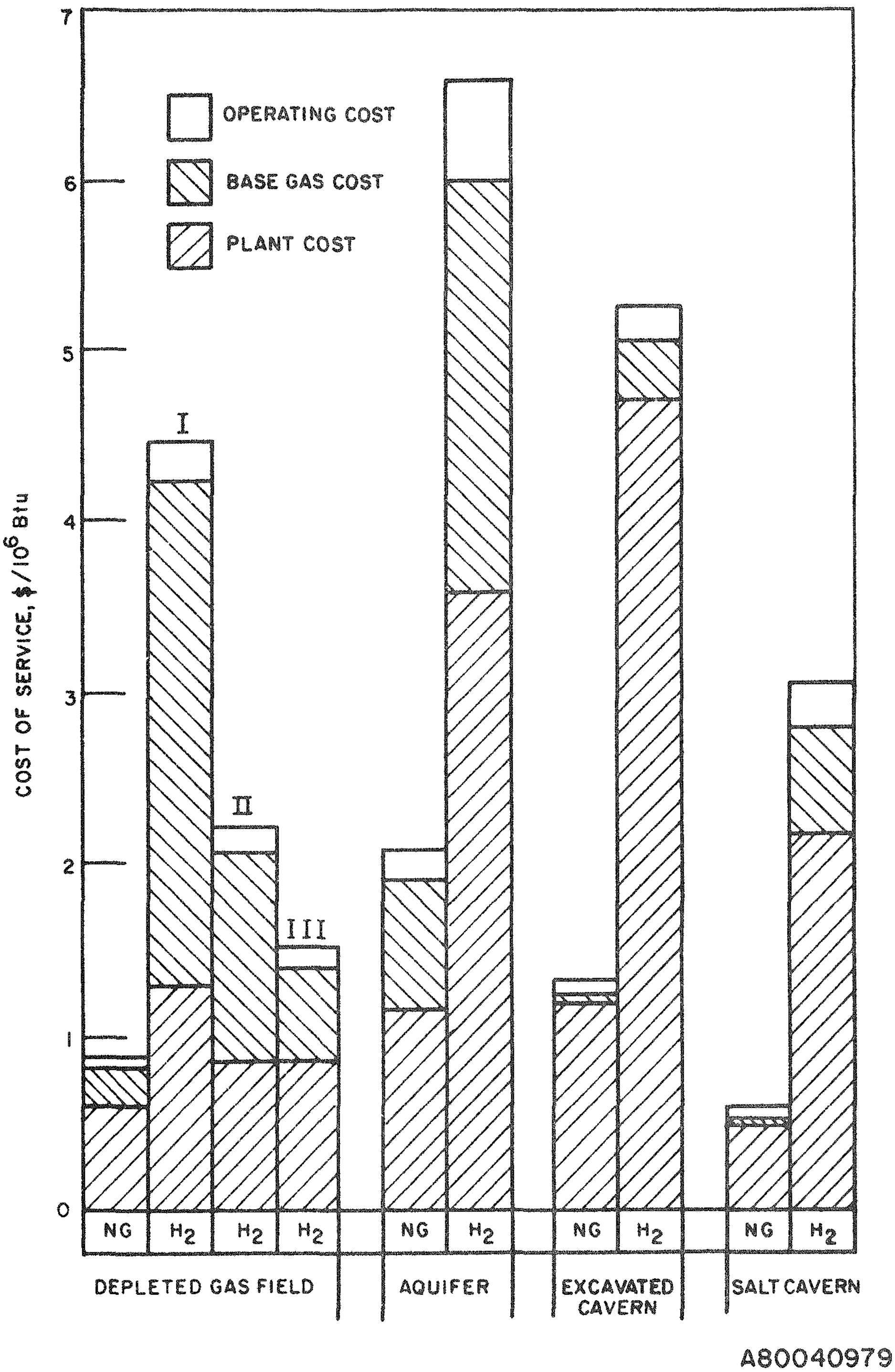

Figure 38. BASE-CASE COSTS OF SERVICE FOR STORING NATURAL GAS AND HYDROGEN IN FOUR TYPES OF RESERVOIRS

plant and operating cost contributions to the cost of hydrogen service ($\$/10^6$ Btu throughput) are from two to four times greater than the corresponding contributions to the cost of natural gas service.

The base-gas cost contributions for hydrogen service also are higher than those for natural gas service. This is primarily a result of the large difference in the assumed costs of hydrogen ($\$6/10^6$ Btu) and natural gas (between \$0.30 and $\$1.60/10^6$ Btu). Base-gas costs constitute a smaller fraction of the total cost of service for the two cavern cases than for the two porous-media cases because the economics of cavern storage are dominated by the (plant) cost of creating the caverns themselves. The cost of service for hydrogen (or any expensive fuel) storage is extremely sensitive to the capital investment required for base gas relative to the amount of working gas, as shown by case III in Figure 37 for depleted-field storage. In those three cases, the minimum field pressure was varied. The lower the minimmum field pressure (III II I), the less base gas required and the higher the working gas portion of total field capacity. The absolute installed plant cost rises because of the need for more compression equipment and wells to provide deliverability at lower pressures. However, the overall cost of service decreases because a higher throughput of working gas from which to recover investment and a reduced base-gas requirement more than compensate for the extra plant cost.

Note that this method of reducing base-gas requirements cannot be applied to all storage operations. In aquifers, or other porous media with an active water drive, a large reduction of field pressure in one season would result in water invasion, which would reduce field capacity in subsequent seasons or cycles. Also, reducing the minimum pressure in a washed salt cavern can result in salt creep and reduced cavern volume. Although lowering the minimum field pressure is not applicable to all storage options, the potential for lowering the cost of service is great enough that other methods of increasing the working/base gas ratio (raising the maximum field pressure slightly or operating caverns in a liquid-displacement mode, for example) should be investigated thoroughly.

C. Future R&D Recommendations

This project identified several areas that are worth further study, but are beyond the scope of this project. These areas are discussed below, and specific recommendations for further research are made.

1. Embrittlement

This study concludes that it would not be safe to operate existing gas storage reservoirs at pressures in excess of 1000 psi because of hydrogen embrittlement in commonly used materials of construction. In addition, ongoing research in the metallurgy of hydrogen embrittlement has not conclusively pinpointed those materials that can be used in a hydrogen distribution network. Basic study must continue in this area. The upper pressure limit for a natural gas storage reservoir at this time is 5000 psi; this value is determined primarily by the geology of the reservoir formation and to a lesser degree by the costs of compression. Therefore, we encourage research in the area of hydrogen environment embrittlement in the range of 1000 to 5000 psi.

2. Use of Existing Hydrogen Safety Codes

The legal implications of assuming the present voluntary hydrogen safety code must be determined. If, for some reason, the present code is not applicable to underground storage, alternatives should be suggested and approved.

3. Effects of Supply-Market Options on Underground Storage

One assumption made in this study was that the hydrogen from storage would be used for fuel in a hydrogen-natural gas pipeline distribution system. An annual load cycle of 5 months injection-5 months withdrawal was assumed. The type of load cycle the reservoir might experience was not one of the parameters varied in this study. Each reservoir type investigated here was originally designed for a particular type of service. The integrated study of the source of hydrogen, storage reservoir, distribution system, and end use was beyond the scope of this project. Therefore, we recommend an investigation of the various possible hydrogen distribution schemes.

4. Economics of Supplying a Variable Hydrogen Natural Gas Mix from Storage

One of the economic difficulties immediately recognized was the problem of computing the cost of service when hydrogen might be stored in a reservoir that had previously been used for natural gas and some of the natural gas was left in the reservoir as the base gas. If the hydrogen were to be delivered to a natural gas-hydrogen distribution system, mixing would be allowed in the reservoir. (This study considered only the effect of delivering pure hydrogen; mixing was assumed not to occur.) Although analytical techniques are available to determine the composition of the gas delivered from the reservoir; the cost of service becomes exceedingly difficult to determine if cheaper natural gas is delivered with the hydrogen, and the base gas eventually becomes 100% hydrogen. In addition, the time may come in the history of the field when natural gas is reinjected. These complications were beyond the scope of this project and might be worth further investigation.

5. Economics of a Shallow Salt Cavern Operated in a Water-Compensated Mode

No cavern in the United States stores natural gas in a brine-compensated mode. The operation at Teeside in the United Kingdom does store hydrogen in a salt cavern by using a water-compensated mode, but detailed information about that operation is not available. There are several apparent advantages to this type of operation: 1) The necessity of a base gas to provide the reservoir pressure is eliminated; 2) the reservoir can be operated at a constant pressure, which simplifies the aboveground facilities; and 3) the problems of mixing with another gas in the reservoir are eliminated. The additional costs of removing and injecting water into the cavern must be incorporated into the costs of service, however. The details of operating in this manner were not investigated, although it appeared, late in this study, as though this method might be the most cost-effective, especially if shallow salt formations are used. This particular mode of operation is especially worth further investigation.

6. Effect of Potential Odorants and Colorants on Hydrogen Chemical Reactions

At this time, we are unaware of particular odorants or colorants that might be added to hydrogen to make it more detectable in the same way as sulfides and sulfites are added to natural gas. The possible effects of these additives on embrittlement or reactions with reservoir minerology therefore are unknown. Future examinations into possible additives must include a consideration of their effect in underground storage operations.

7. Allowable Methane Content in Hydrogen in the Design of Hydrogen Burners

Although it has been established that existing methane burners can function safely and efficiently with up to 20% hydrogen in the natural gas, it has not been established how much natural gas can exist in a predominantly hydrogen system for hydrogen burners to function safely and efficiently. This is another area that requires engineering research.

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APPENDIX A.

(Contractual Statement)

APPENDIX A. Program Plan

INTRODUCTION

Contract No. 453439-S has been awarded to the Institute of Gas Technology (IGT) following a competitive evaluation of responses to Brookhaven's RFP No. HYD 77-1. The research is to be performed by a team consisting of –

- IGT (prime contractor)
- Dames and Moore (subcontractor)
- Texas Gas Transmission Corp. (participant donating services and information)
- Northern Illinois Gas (participant donating services and information)
- Transco Energy Company (participant donating information)
- Southern California Gas (participant donating information).

Start date for the work is August 14, 1978, and the contracted duration is 13 months.

This plan is submitted as required under Task 1 – Program Plan. This plan outlines details of work to be performed in the remaining four tasks under the contract. These tasks are as follows:

- Task 2 – Feasibility Based on Current Practice
- Task 3 – Current Cost of Underground Gas Storage
- Task 4 – Estimated Cost for Underground Storage
- Task 5 – Research and Development Requirements.

Development of the plan has involved a series of three meetings. The first was an in-house IGT meeting in which the availability of relevant data and the means for accomplishing the work were examined in detail. The second meeting involved IGT and Dames and Moore personnel. This meeting carefully reviewed phasing of detailed portions of the research to ensure orderly progression to substantive conclusions. The third meeting involved IGT, Dames and Moore, Northern Illinois Gas, and Texas Gas Transmission Corp. Emphasis was upon developing a common understanding of current natural gas industry storage practice and defining the means for maximizing the relevance of the research to the natural gas industry.

This series of meetings resulted in substantial changes to the time phasing, but not the content, of the research described in the statement of work for Contract No. 453439-S.

The task schedule in IGT's Proposal No. E2G1/78A, which constitutes the statement of work under Contract No. 435439-S, places primary emphasis upon engineering and scientific issues during the first half of the research and upon economic analysis during the second half of the work. The three meetings described above achieved consensus that this approach contained the risk of expending excessive effort on engineering and scientific issues with minimal economic significance. Conversely, there was a risk that the level of effort prescribed in the contract would be expended before economic analysis revealed technical issues warranting heavy concentration of effort.

The plan presented herein removes that risk by providing a preliminary assessment of the economics for each type of underground storage at the midpoint of the program. Parameter variations in this economic assessment will identify the technical issues that warrant emphasis during the second half of the program.

The details of conduct of each of the remaining tasks, a revised manpower/resources allocation chart, and project milestones are discussed below.

TASK 2. FEASIBILITY BASED ON CURRENT PRACTICE

The objectives, scope, and technical aspects of the investigative approach for this task and its six subtasks as described on pages 22 through 29 of IGT's Proposal E2G1/78A remain unchanged and are incorporated herein by reference. However, the scheduling of the work has been revised such that the specific subtasks descriptions are no longer an appropriate breakdown for manpower/resource allocation. The planned conduct of Task 2 work consists of first establishing the basis for preliminary economic assessment and then concentrating effort upon those technical issues revealed to be most significant in parametric economic analyses. The manpower/resources allocation reflects this division as substasks 2a and 2b.

Subtasks 2a. Preliminary Assessment

Work under this subtask will involve both generic studies and preliminary evaluations of the conversion of specific underground storage facilities to hydrogen service.

The generic studies will consist of –

- Describing existing underground natural gas storage facilities so that the range of operating conditions can be considered in addressing economics of locations other than those specifically evaluated in detail
- Summarizing existing data on leakage from natural gas storage facilities and estimating the relevance of leakage to underground storage of hydrogen

- Determining the limitations on operating pressures due to hydrogen embrittlement of metals.

Preliminary site-specific evaluations will be performed for conversion of a representative aquifer, a depleted field and a salt cavern storage facility to hydrogen service. The specific facilities selected are –

- Aquifer storage: The Northern Illinois Gas Media Field has been selected for evaluation. Although this field has not yet been placed into natural gas storage service, the availability of current and detailed geological data, engineering design, and cost estimates make this a desirable candidate
- Depleted field: The Texas Gas Transmission Hanson Field has been tentatively selected for the preliminary study. This field has been in storage operation for 14 years
- Salt cavern: The Transco Energy Co. Eminence Dome storage facility will be used.

A summary description of these facilities is presented in Table A-1.

Table A-1. DESCRIPTION OF PRESENT UNDERGROUND STORAGE FACILITIES

Item	Galesville Formation	Hanson Storage Field	Eminence Salt Dome
Storage Formation	Media (Galesville)	Tar Springs	Eminence
Year Activated	--	1965	1968
Average Depth to Reservoir, ft	2,000	2,250	6,200
Capacity Volume, 10^3 CF	20,600,000	12,087,322	2,920,000
Pressure at Capacity, psig WH	925	1,003	3,950
Base Volume, 10^3 CF	16,000,000	8,160,217	920,000
Pressure at Base, psig MH	925	677	1,275
Deliverability, 10^3 CF/day	100,000	71,402	375,000
Number of Wells			
Injection and Withdrawl	5	30	2
Observation	8	2	--
Installed Horsepower	2,500	660	2,000
Acres in Storage Area	2,510	3,021	--

The preliminary evaluation of the conversion of each facility to hydrogen service will consider all factors discussed in Task 2 of IGT's Proposal E2G1/78A. However, simplifying assumptions will be used to avoid excessive expenditure of effort on any of the numerous detailed technical considerations. To the extent that simplifying assumptions require bias, bias will be in the direction of higher cost for operation, environmental protection, or safety of operation.

Results of these generic and site-specific studies will provide the basis for preliminary economic assessment and parametric studies in Task 3.

Subtask 2b. Detailed Technical Evaluations

Work performed under this subtask will concentrate upon the technical issues with the greatest economic and safety significance for underground storage of hydrogen. Possible candidates for such emphasis are –

- Impermeation techniques for mine storage
- Refinement of hydrogen embrittlement considerations to take into account the metallurgy of specific components of a storage facility
- Means for minimizing the costs of "cushion gas."

TASK 3. CURRENT COST OF UNDERGROUND GAS STORAGE

The objective, scope, and investigative approach for this task remain consistent with those described on the appended pages 30-32 of IGT's Proposal E2G1/78A. However, interaction with participating companies during the Task 1 led to appropriate refinement of the investigative approach and timing of manpower/resources allocation. These changes are dictated by the necessity to develop and test the detailed methodology for economic analysis as well as to provide the preliminary economic analyses which will be used to define detailed technical work in Subtask 2b.

Currently, there are wide variations in the formats used for identifying the cost components in gas storage operations. Similarly, there are wide ranges in the formats used to describe and to analyze the system economics of storage operations. The reasons for these ranges are one or more of the following –

- Differing objectives in the storage operations (short-term peakshaving, annual load balancing, or emergency service during major short-term losses of supply)
- Differing internal organization and reporting requirements of different companies because of differences in the relationships of gas storage operations to other corporate activities

- Varying ground rules by the various Government agencies involved in regulating natural gas company operations (the Internal Revenue Service for tax considerations, state or local regulatory agencies for distribution companies, and the Federal Energy Regulatory Commission for interstate transmission companies).

For work under this contract, IGT will adopt a format and methodology for economic analysis that provides results reasonably consistent with the various formats of participating and cooperating companies. IGT's current proposed format for identifying and measuring the cost components for each of the storage options is shown on Table A-4. This format will be revised as the methodology for system economics is developed and tested against methane storage operations by participating companies.

This necessity for developing the format and methodology to be used in consistent economic analyses makes it appropriate to divide Task 3 into two subtasks as described below.

Subtask 3a. Develop and Test the Economics Format and Methodology

The IGT format and methodology for system economics will seek an acceptable compromise of those reflected in applications to regulatory agencies by participating companies. The adequacy of IGT's methodology and format will be established by analyzing methane storage data provided by participating companies and by soliciting company reviews of IGT's results.

Table A-4. STORAGE COST FORMAT

Cost Sector	Cost Component	Cost Subcomponent
I. Site Acquisition	A. Locating Storage Field	
	B. Preliminary Field Testing	
		1. Size of Field
		2. Permeability
		3. Old Well Locations
		4. Old Well Usability
	C. Permits and Approvals	
		1. Federal
		2. State
		3. Local
		4. Local Public Relations
		5. Time To Accomplish
	D. Site Acquisition	
		1. Options
		2. Purchase
		3. Leases
	E. Right-Of-Way Acquisition (to pipeline & customers)	
		1. Options
		2. Purchase
		3. Leases

Table A-4, Cont., STORAGE COST FORMAT

Cost Sector	Cost Component	Cost Subcomponent
II. Field Preparation		
	A. Field Testing	
		1. Size
		2. Permeability
		3. Old Well Locations
		4. New Well Locations
		5. Old Well Usability
	B. Reservoir Engineering	
	C. Facility Design	
	D. Old Well Rehabilitation/Closing	
	E. New Well Construction & Drilling	
	F. Building Design & Construction	
	G. Equipment Purchasing & Installation	
		1. Well
		2. Pipefields
		3. Compressors & Pumps
		4. Gas Preparation Cleaning, etc.
		5. Control & Connectors
		6. Communications
	H. Landscaping	
	I. Base Gas Injection & Field Testing	
	J. Personnel	
		1. Administration
		2. Engineering
		3. Financial
		4. Miscellaneous
	K. Financial Factors	
		1. Financing Costs
		2. Insurance
		3. Miscellaneous Fees & Costs
III. Operations		
	A. Start-Up	
	B. Performance	
		1. Capacity Base, Working, Reserve
		2. Annual Flow Through
		3. Losses, Unaccounted for Gas Leakage
		4. Years of Operation: 10, 20, 30, etc.
	C. Maintenance, Repair & Replacement	
		1. Spares
		2. Service
		3. Materials
		4. Replacement Equipment
	D. Utilities	
		1. Fuel
		2. Electricity
		3. Water

Table A-4, Cont., STORAGE COST FORMAT

Cost Sector	Cost Component	Cost Subcomponent
	E. Personnel	
		1. Management
		2. Landscaping
		3. Wells
		4. Gas-Handling Compressors, Injectors, Pipefields, Valves, etc.
		5. Gas-Cleaning Cleaning, Dehydration, Desulfurization
	F. Financial Factors, Other	
		1. Working Capital
		2. Depreciation
		3. Lease/Mortgage, etc. Costs
		4. Taxes, etc.
		5. Insurance
IV. Close Down		
	A. Base Gas Recovery	
	B. Well Hole Cleaning (inert gas injection, etc.)	
	C. Well Hole Closing	
	D. Landscaping	
	E. Equipment Sale	
	F. Leasehold & Property Sale	
V. Ownership/Financing		
	A. Owner	
	B. Capitalization Structure	
		1. % Equity
		2. % Debt, etc.
		3. % Leasing
	C. Equity Cost	
		1. Internal Rate of Return Requirement
	D. Debt Cost	
		1. Interest
		2. Life of Debt

Subtask 3b. Perform Hydrogen Storage Economic Assessments

The format and methodology for economic analyses developed in Subtask 3a will be used for preliminary economic assessment for the four potential types of underground hydrogen storage (aquifer, depleted field, salt cavern, and mined cavern). These assessments will be for the three locations subjected to site-specific technical examination in Subtask 2a plus a hypothetical mined storage facility. The economic analyses for aquifer, depleted field, and salt cavern storage will cover both 1) the conversion from methane storage and 2) the hypothetical development of new hydrogen storage facilities at the locations of the site-specific evaluations.

These preliminary economic assessments, plus parametric variations on each, will provide definitions of technical issues whose economic significance warrants more detailed examination in Subtask 2b. For example, if the economics of mined storage appear reasonably attractive, then it may be appropriate to examine impermeation techniques in greater detail.

As the detailed technical investigations provide refinement of hydrogen storage system design, the economic analyses will be redone. Subtasks 2b and 3b will conclude with substantive, technical, safety, and economic assessments for all four potential types of underground hydrogen storage.

Achieving this end result requires resolution of a problem in addition to the "anticipated problem areas" identified on pages 31 and 32 of IGT's Proposal E2G1/78A. The additional problem is that the economics of underground storage are strongly dependent upon the relationship between the storage facility and the supply-market system served by the storage facility. The wide range of variation is apparent when one recognizes the substantial differences between the three facilities described on pages 4 to 6 and the extreme of the Helium storage facility near Amarillo, Texas. The three storage facilities described on pages 4 to 6 are each operated in different market environments as discussed below.

- Hanson Field (Depleted Gas Reservoir): This is one of several storage facilities providing annual load balancing for an interstate pipeline system. Many of the customers are distribution companies which have their own storage for peaking and a portion of annual load balancing. In this market environment, single day deliverability of only 1.8 percent of working gas volume is adequate.
- Media Field (Aquifer Storage): This will be one of several fields operating to meet both peaking and annual load balancing requirements of a large distribution company. We already know single day deliverability would be about 2.2 percent of working gas capacity. This is a percentage somewhat higher than the Hanson Field, but still less than may be required to meet peaking demands for a smaller distribution company serving predominantly residential comsumers.
- Eminence Facility (Washed Cavern Storage): When Transco placed this facility in operation in 1968, the primary objective was gas supply to a large interstate pipeline during times when Gulf of Mexico production was curtailed by hurricanes. As such, daily deliverability is 38 percent of working gas capacity.

Because increasing deliverability requires increased cost for drilling, it is apparent that economic analyses based upon the market conditions unique to each of the above storage facilities will not be compatible with comparing economics for the different types of storage. Further, such a comparison may well not be meaningful because geological conditions appropriate to each storage type are generally in mutually exclusive geographical areas. It is recommended that a concensus on supply and market assumptions for economic analysis of storage be achieved during the quarterly meeting with BNL at the end of Subtasks 2a and 3a.

TASK 4. ESTIMATED COSTS FOR UNDERGROUND HYDROGEN STORAGE

The objectives, scope, and technical aspects of the investigative approach for this task as described in pages 32 through 35 of IGT's Proposal E2G1/78A remain unchanged and are appended for reference. The scheduling of the work has been revised so that it begins when Tasks 2 and 3 end. The economic format and methodology developed in Task 3 will be used in the economic analysis for conversion of one specific gas reservoir to storage of hydrogen.

It is anticipated that the primary criterion for selection of a specific type of storage and location will be maximum confidence that successful, safe operation can be achieved. Minimum uncertainty in economics will be a part of the primary criterion but, to the extent costs are judged reasonable, minimal emphasis will be placed upon relative economics for the different types of storage.

TASK 5. RESEARCH AND DEVELOPMENT REQUIREMENTS

The objective, scope, and investigative approach for this task will be consistent with pages 35 through 37 of IGT's Proposal E2G1/78A, which are appended for reference. However, additional information that IGT has obtained regarding underground storage of hydrogen in Europe makes it highly probable that IGT will not reach conclusion 3 "underground storage of hydrogen is unsafe or not economic at this time". In Britain, pure hydrogen has been stored for several years in a washed salt cavern. In this operation, the hydrogen storage is an economically viable buffer between facilities that create hydrogen and facilities that use hydrogen to produce petrochemicals. In France, the Beynes aquifer storage facility was used for 6 years to store a manufactured gas that consisted of 50% to 60% hydrogen. No safety problems were encountered and the losses, if any, were well within acceptable bounds for underground storage operation. In 1973, the Beynes field was converted to natural gas, leaving a portion of the manufactured gas as "cushion". Minimal mixing of gases occurred during conversion, and operation has, since 1973, been encouraging in relation to use of a below cost base gas for aquifer storage of hydrogen.

The European experience will be examined in detail during conduct of this research program. However, present knowledge is sufficient to anticipate that Task 5 work will choose locations for possible use in a future underground hydrogen-storage demonstration project. In addition, IGT may recommend specific future R&D objectives to improve or reduce uncertainty in the economics of hydrogen storage.

CONTRACT MANAGEMENT SUMMARY REPORT

The attached Contract Management Summary Report (Form ERDA 536) indicates the project cost, manpower, and schedule of performance. Under the contract, the milestone status indicates the completion date for each task and subtask.

It is recommended that the groupings of task completion dates be regarded as major milestones to coincide with quarterly meetings with BNL. The timing and major issues to be covered at each of these major milestones (quarterly meetings) would be as follows –

- Early January 1979: Subtasks 2a and 3a will be complete. Major decisions to be made at the meeting would concern details of the technical investigations to be performed in Subtask 2b plus market assumptions for economic analyses to be performed in Subtask 3b.
- Early April 1979: At this time Task 2 will be complete and the economic assessments for both conversions and construction of new hydrogen storage facilities (Task 3b) will be nearing completion. This will be the appropriate time for BNL participation in a decision as to which storage facility should be examined in detail in Task 4. At the same time, sufficient progress will have been made in Task 5 for joint deliberations with BNL to result in an agreement upon the general nature and format for presenting the final conclusions on future R&D and sites for future demonstration experiments.
- Early August 1979: This third quarterly meeting will constitute the oral presentation of final results as specified in Contract No. 453439-S.

FORM ERDA 536
(10 – 76)

U S ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

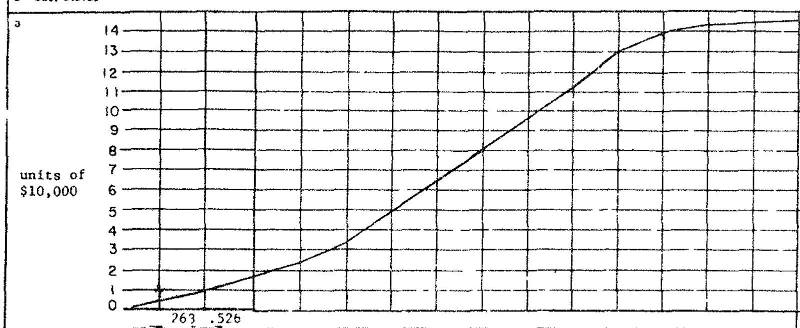
CONTRACT MANAGEMENT SUMMARY REPORT

FORM APPROVED
OMB NO 38R

1 Contract Identification Underground Storage of Hydrogen Gas	2 Reporting Period 14 Aug. through 8 Sept.	3 Contract Number 453439-S
4 Contractor (name and address) Institute of Gas Technology 3424 South State Street Chicago, Illinois 60616		5 Contract Start Date 14 August 1978 6 Contract Completion Date 14 September 1979

7 Months	A	S	O	N	D	J	F	M	F	M	J	J	A	S	8 FY 78-79

9 Cost Status



Accrued Costs			O	N	D	J	F	M	F	M	J	J	A	S
	b Planned		1 336	1 454	1 461	1 454	1 678	1 421	1 838	1 717	0 790	0 303	0 184	0 105
	c Actual													
	d Variance													

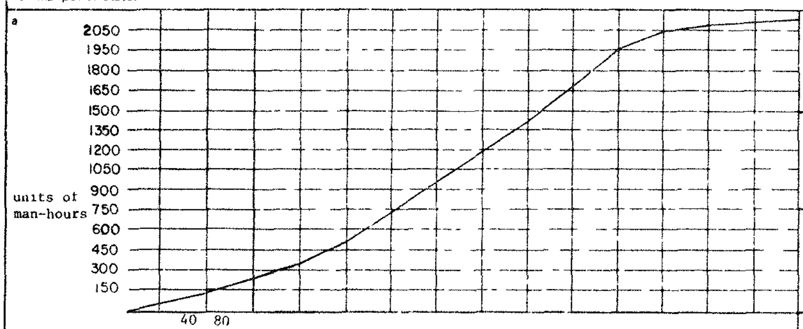
e Actual Costs Prior FYs

f Planned Costs Prior FYs

g Total Projected Accrued Costs for Contract
$144,100

h Total Contract Value
$144,100

10 Manpower Status



Manpower			O	N	D	J	F	M	F	M	J	J	A	S
	b Planned		203	203	204	203	255	216	261	201	120	28	28	16
	c Actual													
	d Variance													

e Actual Manpower Prior FYs

f Planned Manpower Prior FYs

g Total Projected Manpower for Contract
2118

h Total Contract Manpower
2118

11 Major Milestone Status

a 1 Program Plan

b 2 Feasibility Study

c 2a. Prelim Asses

d 2b. Detailed Tech Eval

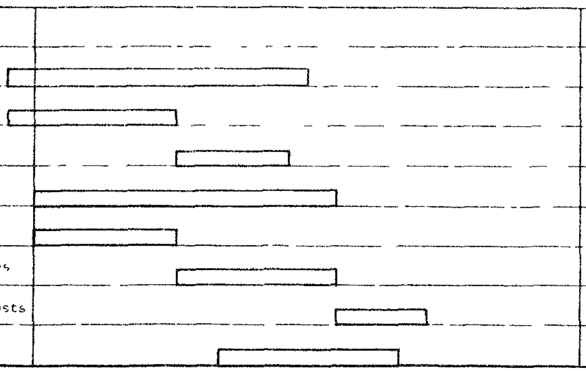
e 3. Current Costs of Underground Storage

f 3a. Format & Meth Dev

g 3b. Hydrogen Econ. Asses

h 4. Estimated Storage Costs

5. R&D Requirements



12 Remarks

Total Costs & Manpower Include Final Reporting & Review

13 Signature of Contractor's Project Manager and Date	14 Signature of Government Technical Representative and Date

MANPOWER PLAN

The attached Manpower Plan (Form ERDA 534P) indicates the level of man-hours of direct labor to be supplied by IGT for the various tasks. The units are man-hours and the total is 2118 man-hours, as specified in Contract No. 453439-S.

FORM ERDA 534P
(10 – 76)

U S ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

MANPOWER PLAN

FORM APPROVED
OMB NO 38R
Page of

1 Contract Identification	2 Contract Number
UNDERGROUND STORAGE OF HYDROGEN GAS	453439-S

3 Contractor (name address)	4 Contract Start Date / 5 Contract Completion Date
Institute of Gas Technolog 3424 South State Street Chicago, Illinois 60616	4 Contract Start Date: 14 August 1978 5 Contract Completion Date: 14 September 1979

6 Identification Number	7 Reporting Category (e g contract line item or work breakdown structure element)	8 Planned Prior Fiscal Years	9 Actual Prior Fiscal Years	10 Planned Current Fiscal Year 1978 A	S	O	N	D	1979 J	F	M	A	M	J	J	Total	11 Planned Future Fiscal Years 1979 a A	b S	c	d	e	12 Planned Subsequent Fiscal Years to Completion	13 Total Planned (Columns 9 through 12)
1	Program Plan																						
1	Sub-Total			40	40											80							80
2	Feasibility Study																						
2a	Preliminary Assessment				40	10	100	100								340							340
2b	Detailed Technical Evaluation								100	100	60					260							260
2	Sub Total				40	[illegible]	100	100	103	[illegible]	60					600							600
3	Underground Storage Current [illegible]																						
3a	Format & Meth Development					10	103	104								310							310
3b	Hydrogen [illegible] Assessment								103	103	104					310							310
3	Sub-Total					[illegible]	[illegible]	104	103	103	1 4					[illegible]							620
4	Estimated Costs for Storage													[illegible]	*								
4	Sub Total											208	208	104		20							520
5	R&D Requirements																						
	Sub Total									52	52	53	53			210							210
6	Reporting and Review																						
6	Sub Total													1[illegible]	28	44	28	16					88
14 Total				40	80	203	203	20[illegible]	203	2[illegible]	216	261	261	12[illegible]	28	2074	28	16					2118

15 Remarks	16 Manpower Expressed in	17 Manpower Plan Date
DETAIL PLAN	Man-Hours	8 September 1978

18 Signature of Contractor s Project Manager and Date	19 Signature of Government Technical Representative and Date

APPENDIX B. Properties of Hydrogen and Methane

APPENDIX B. Properties of Hydrogen and Methane

Property	Hydrogen	Methane
Limits of Flammability in Air, vol %	4.0 to 75.0	5.3 to 15.0
Limits of Detonability in Air, vol %	18.3 to 59.0	6.3 to 13.5
Stoichiometric Composition in Air, vol %	29.53	9.48
Minimum Energy for Ignition in Air, mJ	0.02	0.29
Autoignition Temperature, °K*	858	813
Hot Air-Jet Ignition Temperature, °K	943	1493
Flame Temperature in Air, °K	2318	2148
Percentage of Thermal Energy Radiated from Flame to Surroundings, %	17 to 25	23 to 33
Burning Velocity in NTP Air, cm/s	265 to 325	37 to 45
Detonation Velocity in NTP Air, km/s	1.48 to 2.15	1.39 to 1.64
Diffusion Coefficient in NTP Air, cm^2/s	0.61	0.16
Diffusion Velocity in NTP Air, cm/s	$\lesssim 2.00$	$\lesssim 0.51$
Buoyant Velocity in NTP Air, m/s	1.2 to 9	0.8 to 6
Maximum Experimental Safe Gas in NTP Air, cm	0.008	0.12
Quenching Gas in NTP Air, cm	0.064	0.023
Detonation Induction Distance in NTP Air	L/D ≈ 100	--
Limiting Oxygen Index, vol %	5.0	12.1
Vaporization Rates (Steady State) of Liquid Pools without Burning, cm/min	2.5 to 5.0	0.05 to 0.5
Burning Rates of Spilled Liquid Pools, cm/min	3.0 to 6.6	0.03 to 1.2
Energy of Explosion, g TNT/g fuel	~24	~11
Energy of Explosion, g TNT/cm^3 NTP liquid fuel	1.71	4.56
Energy of Explosion, kg TNT/m^3 NTP gaseous fuel	2.02	7.03
Energy of Explosion, g TNT/kJ of stored heating value	0.17	0.19
Flash Point, °K	Gaseous	Gaseous
Toxicity	Nontoxic (asphyxiant)	Nontoxic (asphyxiant)

*The Autoignition temperature of methane is usually higher than that of hydrogen. The temperature of each varies at over a hundred centigrade degrees depending on the air/oxygen mixture.

APPENDIX C. Glossary

(American Geological Institute, Dictionary of Geological Terms. Garden City New York: Anchor Press, 1976)

APPENDIX C. Glossary

Anhydrite – a mineral, anhydrous calcium sulfate, $CaSO_4$. Orthorhombic, commonly massive in evaporite beds.

Anticlinal – inclined toward each other, as, the ridge tiles of the roof of a house; of, or pertaining to, an anticline.

Bedding planes – in sedimentary or stratified rocks, the division planes that separate the individual layers, beds, or strata.

Capillarity – the attractive force between two unlike molecules, illustrated by the rising of water in capillary tubes of hairlike diameters or the drawing up of water in small interstices, as those between the grains of a rock.

Colloids – a substance in a state of fine subdivision with peculiar properties because of its extremely high surface area. A common colloid in nature is clay with unusual properties such as plasticity, thixotrophy, and swelling. A fine-grained material that is held in suspension.

Compressibility – the change of specific volume and density under hydrostatic pressure; reciprocal of bulk modulus.

Connate water – water entrapped in the interstices of a sedimentary rock at the time the rock was deposited. Water adsorbed on mineral grains of reservoir rock and not produced with oil or gas.

Diapirs – a dome or anticlinal fold, the overlying rocks of which have been ruptured by the squeezing out of the plastic core material. Diapirs in sedimentary strata usually contain cores of salt or shale. Igneous intrusions also may show diapiric structure.

Dolomite – a mineral, $CaMg\text{-}(CO_3)_2$, commonly with some iron replacing magnesium (ankerite). Hexagonal rhombohedral. A common rock-forming mineral. A term applied to those rocks that approximate the mineral dolomite in composition. Synonym – magnesian limestone. It occurs in a great many crystalline and noncrystalline forms the same as pure limestone, and among the rocks of all geological ages. When the carbonate of magnesia is not present in the above proportion, the rock may still be called a magnesian limestone, but not a dolomite, strictly speaking.

Erathem – the largest recognized time-stratigraphic unit, next in rank above system; the rocks formed during an era of geologic time, such as the Mesozoic Erathem composed of the Triassic System, the Jurassic System, and the Cretaceous System.

Evaporites – one of the sediments that are deposited from aqueous solution as a result of extensive or total evaporation of the solvent.

Ferromagnetic – refers to those paramagnetic materials with a magnetic permeability considerably greater than one. They are attracted by a magnet.

Gneiss – a coarse-grained rock in which bands rich in granular minerals alternate with bands in which schistose minerals predominate.

Halite – rock salt. A mineral, NaCl; isometric. A common mineral of evaporites.

Hydrophilic – having strong affinity for water; said of colloids that swell in water and are not easily coagulated.

Igneous – formed by solidification from a molten or partially molten state. Said of the rocks of one of the two great classes into which all rocks are divided, and contrasted with sedimentary. Rocks formed in this manner also have been called plutonic rocks and are often divided for convenience into plutonic rocks and volcanic rocks, but there is no clear distinction between the two.

Indurated – rendered hard; confined in geological use to masses hardened by heat, baked, etc., as distinguished from hard or compact in natural structure. In modern usage the term is applied to rocks hardened not only by heat, but also by pressure and cementation.

Interstice – pore; void.

Isostatic – subject to equal pressure from every side; being in hydrostatic equilibrium.

Lithology – the physical character of a rock, generally as determined megascopically or with the aid of a low-power magnifier. The microscopic study and description of rocks.

Mesozoic – one of the grand divisions or eras of geologic time, following the Paleozoic and succeeded by the Cenozoic Era; comprises the Triassic, Jurassic, and Cretaceous Systems. Also, the erathem of strata formed during that era.

Metamorphism – process by which consolidated rocks are altered in composition, texture, or internal structure by conditions and forces not resulting simply from burial and the weight of subsequently accumulated overburden. Pressure, heat, and the introduction of new chemical substances are the principal causes, and the resulting changes, which generally include the development of new minerals, are a thermodynamic response to a greatly altered environment. Diagenesis has been considered to be incipent metamorphism.

Metamorphic rock – includes all those rocks that have formed in the solid state in response to pronounced changes of temperature, pressure, and chemical environment, which take place, in general, below the shells of weathering and cementation.

Orthorhombic – refers to either symmetry of movement or symmetry of fabric. Orthorhombic symmetry of movement is exemplified by the motion that occurs when a sphere is subjected to a single compressive force acting along the vertical axis but is constrained on two opposite sides. Orthorhombic symmetry of fabric is the symmetry of an ellipsoid; there are three planes of symmetry.

Paleozoic – one of the eras of geologic time – that between the Precambrian and Mesozoic – comprising the Cambrian, Ordovician, Silurian, Devonian, Carboniferous (Mississippian and Pennsylvania), and the Permian Systems. Also, the erathem of rocks deposited during the Paleozoic Era.

Permeability – the permeability (or perviousness) of rock is its capacity for transmitting a fluid. Degree of permeability depends upon the size and shape of the pores, the size and shape of their interconnections, and the extent of the latter. It is measured by the rate at which a fluid of standard viscosity can move a given distance through a given interval of time. The unit of permeability is the darcy.

Porosity – the ratio of the aggregate volume of interstices in a rock or soil to its total volume. It is usually stated as a percentage.

Rheological (rheology) – the study of the deformation and flow of matter.

Sand lens – a sand body having the general form of a convex lens.

Schistose – a medium- or coarse-grained metamorphic rock with subparallel orientation of the micaceous minerals that dominate its composition.

Sediment – solid material settled from suspension in a liquid. Solid material, both mineral and organic, that is in suspension, is being transported, or has been moved from its site of origin by air, water, or ice, and has come to rest on the earth's surface either above or below sea level.

Shale – a laminated sediment in which the constituent particles are predominantly clay grade. Shale includes the indurated, laminated, or fissile claystones and siltstones. The cleavage is that of bedding and such other secondary cleavage of fissility that is approximately parallel to bedding. The secondary cleavage has been produced by the pressure of overlying sediments and plastic flow.

Spalling (spall) – to break off in layers parallel to a surface. Relatively thin, commonly curved and sharp-edged pieces of rock produced by exfoliation.

Stratigraphic (stratigraphy) – the branch of geology that treats the formation, composition, sequence, and correlation of the stratified rocks as parts of the earth's crust.

Tertiary – the older of the two geologic periods comprising the Cenozoic Era; also, the system of strata deposited during that period.

Thisotrophy – the property exhibited by some gels of becoming fluid when shaken. The change is reversible.

Viscosity – internal friction due to molecular cohesion in fluids. The internal properties of a fluid that offer resistance to flow.

Vugular (vug) – a cavity, often with a mineral lining of different composition from that of the surrounding rock.

APPENDIX D. Computer Programs for Economic Analysis

APPENDIX D. Computer Program for Economic Analysis

The facility economic analysis program is described in this Appendix; the program was written in the basic language for use on a Textronics 4051 computer. This machine allows interactive use of the program; both program and data changes can be made with immediate CRT display or printout of the results.

The program is divided into six main sections. The first section is a self-explanatory dictionary of variable names, as noted by line 130 of the program. The 38 variables that are defined are basic to managerial finance reference texts.

The second program section is titled "input information." Two initial statements are used for program and printer control. These are followed by two dimension statements. Next, a series of statements print input requirements on the computer screen. The operator types in the eleven demanded inputs as each is demanded sequentially. The inputs, as shown in the listing, are: title, erected plant cost, operating cost per year, extraordinary one-time expense, year of extraordinary expense, throughput per year, cost of debt, cost of equity, fraction of debt financed, plant life, and tax rate.

The erected plant cost used is the total anticipated cost of the facility including depreciable base gas, if applicable, in the case of gas storage fields. This plant cost does not include an allowance for funds used during construction, as this term is calculated in the program.

The operating cost per year is a constant in this program; for any facility contemplated, there is no reason to assume these costs differ each year in constant dollars, assuming full utilization and no extraordinary expenses. (However, a provision was made in the program to allow for any extraordinary expense in any one project year.) The representative cash flow can be either positive or negative. For example, a negative expense, or positive cash flow, could accrue with the sale of base gas at the abandonment of some storage facilities.

The yearly throughput of a facility is a very significant variable. The unit cost or cost of service is directly proportional to throughput for any facility with relatively high capital service costs and correspondingly low operating costs. As a result, input information from engineers about duty cycle was most important in these or any facilities studied.

The next three program input parameters are the cost of debt, cost of equity, and fraction of debt financed. These parameters make up the utility's internal rate of return

(IRR), which must be demanded of the public utility commission to ensure investment. The IRR is subject to general financial market conditions, the specific financial position of the utility seeking financing, the default risk due to facility failure, and the amount requiring financing.

The plant life is another important input parameter. Large differences in facility lives must be equalized in any economic analysis by either using multiple investments for the shorter lived facilities or by investigating a multiple of those facilities to a sufficiently distant future time to negate differences in individual plant life. These issues did not arise in this analysis, as all parts of the facilities were considered to have a depreciable plant life of 27 years and an equivalent plant and financing life. The depreciable plant life has been set by FERC as 27-3/4 years for underground storage facilities. With such a long depreciation period, a year of life in either direction has limited impact on discounted cash flow calculations.

The last input required is the tax rate. To treat all facilities equally, only Federal taxes were considered. The tax rate used through all calculations was 48%.

The third section of the computer program listing is instruction for printing out important input information. All input information is always printed out, except extraordinary expenses. The program was designed so that this item was printed out only if it was not equal to zero to create a more concise printout.

The fourth section of the program listing contains the initial calculations of the main program body along with one printed output, the total depreciable plant cost including the erected plant cost and the allowance for funds used during construction. Specifically, line 1120 of the program listing is a calculation of the weighted average cost of capital based on the debt rate, equity rate, and reaction of debt financed. Lines 1130 through 1220 perform a calculation of the Allowance for Funds Used During Construction (AFUDC).

First, several variables are initialized by including "Y5," the construction period. Next, the yearly construction cost is found by assuming equal construction costs during each construction period. This simplified construction scheduling is in lieu of specific scheduling dictated by particular projects and corporate constraints. It creates a generally applicable program without a sacrifice in accuracy; some projects would have a normal distribution for construction spending, whereas others would have skewed distributions. In the calculation, line 1190 sums the construction costs. Line 1200 calculates the AFUDC, including the depreciable plant cost based on the construction costs (B3), the fraction of debt financed (F1), and the weighted average cost of capital normal distribution for construction spending, whereas others would have skewed distributions. In the calculation, line 1190 sums the construction costs. Line 1200 calculates the AFUDC, including the depreciable plant cost based on the construction costs (B3), the fraction of debt financed (F1), and the weighted average cost of capital (CA). The impact of zero debt financing can be seen easily; the F1 term becomes zero and the AFUDC becomes zero. Line 1210 sums the yearly AFUDC.

After all construction year calculations, the initial plant cost is added to the AFUDC to yield C5, the total depreciable plant cost that can be considered as the interest "rate base" for earnings. This dollar amount is not subject to present value calculations, i.e. adjustment of the money spend over the construction period to its value at the end of that period and at plant startup. This calculation would be done for a project with a multitude of facilities with construction interposed over a long time or by corporations with the construction monies in hand and with the ability to earn their IRR over the construction period. These corporations, including many utilities, can find no advantage in reducing the apparent plant cost due to its future value after construction, when viewed in the present; they do not have those monies from which to earn monies to effectively reduce the apparent plant cost. The second reason for not adjusting the total erected plant cost to future amounts is that utility filings, which this program intends to closely replicate in output, do not consider this adjustment. Line 1240 and 1250 print out the total depreciable plant cost as calculated in the program.

Lines 1260 through 1300 are straightforward. Calculations are made for the amount of debt financing (D1), the amount of equity financing (Y1), the straight-line retirement of debt (D2) and equity (Y2), and straight-line depreciation (De). The straight-line basis is used because it appears in utility filings. For tax purposes, an accelerated depreciation method probably would be chosen to optimize depreciation deductions.

In conventional business practice, debt is not necessarily retired in equal annual amounts. One method of repayment is a mortage or annuity from a present amount for relatively small, short-term loans or for commercial property. A second method employed by industry is a sinking fund with retirement of equal percentages of the debt starting a predetermined number of years in the future. Still another method involves a sinking fund with a large debt repayment in the last year of the secured loan. The specific approach is a matter of needs of both the financial community and the corporation attempting to float a debt issue. A test case comparing mortgage repayment to straight-line repayment resulted in a 1% greater cost of the service for the mortgage repayment approach. This difference is slight compared to those resulting from possible variations in capital cost. Because utilities often do not know their debt repayment structure for a new facility at the time of filing for construction, the straight-line repayment schedule is used in filings as well as in this program.

The straight-line repayment of equity is a term introduced to consider stockholders. If a facility was to be fully depreciated and of no practical value after its service life and if reinvestment of monies did not occur over the facility life, the shareholders would hold interest in a valueless facility of the corporation. The equity repayment term therefore is used to pay back or buy back the stock such that no investment remains at the end of the facility life. In actuality, the stock is seldom bought back unless its market price suggests an excellent investment to the corporation. Instead, monies noted as repurchase monies are retained earnings used to reinvest in other facilities, so that at the end of the original facility life, the original stockholders retain a vested interest in the corporation.

Line 1350 of the program listing presents the standard equation for the capital recovery factor, or amortization factor. The general expression for this factor is:

$$\mathrm{CRF} = \frac{i\ (1 + i)\ n}{(1 + i)^n - 1}$$

where—

$\underline{i}$ = the effective interest rate per period.

$\underline{n}$ = the number of periods.

This factor is the necessary fraction by which a present amount can be expressed as a series of equal future payments including earned interest. The interest rate used in line 1350 is the weighted average cost of capital; the utilities forecast demanded internal rate of return. This basis equation is used in "levelizing" costs from a present amount to a series of future cash flows.

The fifth section of the program listing contains the detailed calculations of this methodology incorporated into one program loop. For each year of plant life, calculations are made for the following —

- Remaining debt (line 1400)
- Interest on debt due debtholders (line 1410)
- Cumulative interest on debt (line 1420)

- Equity still invested in the facility (line 1430)
- Earnings due to equity (line 1440)
- Total expenses (lines 1450 through 1480)
- Yearly revenue requirements, including the adjusted earnings on equity and expenses (line 1490)
- Taxes actually due (line 1500)
- A present value factor, dependent on year and interest rate, to obtain the present value of these revenue requirements (line 1510)
- The present value of revenue requirements (line 1520)
- The average annual cost of service, with the actual revenue requirements divided by the throughput of that year (line 1530)
- An accumulator to sum the present value of revenue requirements for each year (line 1540).

Of these program steps, the calculation of expenses (lines 1450 through 1480) requires further explanation; the remainder are self-explanatory by using general accounting principles, the program line, and the dictionary of variable names. For expenses, a choice of two calculations is made by the program. If there is no extraordinary one-time expense, program line 1460 calculates expenses. If an extraordinary one-time expense, does exist, it is spotted in program line 1450 when J=T4, J being the year counter and T4 being the year of the extraordinary expense. In this case, the program control is transferred to line 1480 where the term E1, the extraordinary expense, is added to expenses of the year. As shown by line 1480, expenses are the addition of depreciation (a noncash expense), interest on debt, yearly operating cost, and the extraordinary expense. If taxes were not considered, depreciation would not appear as an expense. Also note that taxes and equity earnings are treated in the revenue requirements expression, line 1490.

The last computer program section formats and prints the output. A user option in lines 1620 and 1630 can either bypass the extensive output and simply print the levelized cost of service or print out for each year the following: depreciation, debt payment, debt interest, equity payment, equity earnings, expenses, taxes, revenue required, present value of revenue required, throughput, cost of service, and the levelized cost of service. If line 1620 reads Y6=1 (or any non-zero number), the more detailed printout results. With Y6 , only the levelized cost of service is printed.

TEST FOR DISCUSSION

1000.00	ERECTED PLANT COST
100.00	OPERATING COST/YEAR
1000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
10.00	PLANT LIFE - YEARS
0.4800	TAX RATE
1144.00	TOTAL DEPRECIABLE PLANT

YEAR	DEPRECIATION	DEBT PAYMENT	DEBT INTEREST	EQUITY PAYMENT	EQUITY EARNINGS
1	114	69	69	46	69
2	114	69	62	46	62
3	114	69	55	46	55
4	114	69	48	46	48
5	114	69	41	46	41
6	114	69	34	46	34
7	114	69	27	46	27
8	114	69	21	46	21
9	114	69	14	46	14
10	114	69	7	46	7

YEAR	EXPENSES	TAXES	REVENUE RREQUIRED	PRESENT VALUE RR	THRUPUT	SERVICE COST
1	283	63	415	371	1000	$0.42
2	276	57	395	315	1000	$0.39
3	269	51	375	267	1000	$0.37
4	262	44	355	226	1000	$0.35
5	256	38	335	190	1000	$0.33
6	249	32	315	159	1000	$0.31
7	242	25	295	133	1000	$0.29
8	235	19	275	111	1000	$0.27
9	228	13	255	92	1000	$0.25
10	221	6	234	75	1000	$0.23

$0.34 = LEVELIZED COST OF SERVICE

```
100 REM - ECON.1 UTILITY FINANCING PROG.W/AFUDC,ST. LINE DEBT PAY,1*EXP
110 REM
120 REM--------------------------------------SECTION 1
130 REM DICTIONARY OF VARIABLE NAMES
140 REM
150 REM  A1 = AVERAGE ANNUAL COST OF SERVICE
160 REM  B2 = ANNUAL CONSTRUCTION COST
170 REM  B3 = CUMULATIVE CONSTRUCTION FUNDS
180 REM  B5 = ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION,ANNUAL
190 REM  C1 = OPERATING PLANT COST/YEAR
200 REM  C2 = COST OF DEBT
210 REM  C3 = COST OF EQUITY
220 REM  C4 = AVERAGE COST OF CAPITAL
230 REM  C5 = TOTAL DEPRECIABLE PLANT COST
240 REM  D1 = DEBT
250 REM  D2 = EQUITY
260 REM  D3 = DEPRECIATION
270 REM  D5 = DEBT REMAINING
280 REM  F1 = FRACTION DEBT FINANCED
290 REM  E2 = EXTRAORDINARY ONE TIME EXPENSE
300 REM  I1 = INTEREST DURRING CONSTRUCTION
310 REM  I2 = INTEREST ON DEBT
320 REM  I4 = CUMULATIVE INTEREST ON DEBT
330 REM  L1 = PLANT LIFE
340 REM  P1 = ERECTED PLANT COST
350 REM  Q1 = THRUPUT/YEAR
360 REM  R1 = REVENUE REQUIRED EACH YEAR
370 REM  R2 = ANNUAL PV REVENUE REQUIREMENT
380 REM  R3 = SUM PRES VALUE REVENUE REQUIREMENT
390 REM  R4 = LEVELIZED REVENUE REQUIREMENT
400 REM  R5 = LEVELIZED COST OF SERVICE
410 REM  T1 = TAX RATE
420 REM  T2 = TAXES
430 REM  T3 = CONSTRUCTION PERIOD
440 REM  T4 = YEAR OF EXTRAORDINARY ONE TIME EXPENSE
450 REM  V1 = PRESENT VALUE FACTOR
460 REM  V2 = CAPITAL RECOVERY FACTOR FOR LEVELIZING
470 REM  X1 = EXPENSES
480 REM  Y1 = EQUITY
490 REM  Y2 = EQUITY PAYMENT (PAYBACK)
500 REM  Y3 = EQUITY STILL INVESTED
510 REM  Y4 = EARNINGS ON EQUITY
520 REM  Y5 = YEARS OF CONST.(SET IN PROGRAM)
530 REM--------------------------------------SECTION 2
540 REM  INPUT INFORMATION
550 PAGE
560 CALL 'RATE',1200,0,2
570 DIM I2(50),Y3(50),Y4(50),X1(50),R1(50),T2(50)
580 DIM V1(50),R2(50),A1(50),B5(10),D5(50)
590 PRINT 'DCF/REV REQ/COST OF SERVICE ECONOMICS PROGRAMJ'
600 PRINT 'ENTER TITLE FOR RUN'
610 INPUT Z$
620 PRINT 'ERECTED PLANT COST = ';
630 INPUT P1
640 PRINT 'OPERATING COST/YEAR = ';
650 INPUT C1
660 PRINT 'EXTRAORDINARY ONE TIME EXPENSE= ';
670 INPUT E2
680 PRINT 'YEAR OF EXTRAORDINARY EXPENSE= ';
690 INPUT T4
700 PRINT 'THRUPUT/YEAR =';
710 INPUT Q1
```

```
... PRINT "COST OF DEBT = ";
730 INPUT C2
740 PRINT "COST OF EQUITY = ";
750 INPUT C3
760 PRINT "FRACTION DEBT FINANCED = ";
770 INPUT F1
780 PRINT "PLANT LIFE -YEARS = ";
790 INPUT L1
800 PRINT "TAX RATE = ";
810 INPUT T1
820 REM
830 REM----------------------------------------SECTION 3
840 REM  PRINT INPUT
850 PRINT @37,26:1
860 PRINT @40: USING 870:Z$
870 IMAGE 5X,65A,"J"
880 PRINT @40: USING 890:P1
890 IMAGE 10D.2D," ERECTED PLANT COST"
900 PRINT @40: USING 910:C1
910 IMAGE 10D.2D," OPERATING COST/YEAR"
920 IF E2=0 THEN 970
930 PRINT @40: USING 940:E2
940 IMAGE 10D.2D," EXTRAORDINARY ONE TIME EXPENSE"
950 PRINT @40: USING 960:T4
960 IMAGE 10D.2D," YEAR OF EXTRAORDINARY EXPENSE"
970 PRINT @40: USING 980:Q1
980 IMAGE 10D.2D," THRUPUT/YEAR"
990 PRINT @40: USING 1000:C2
1000 IMAGE 10D.2D," COST OF DEBT"
1010 PRINT @40: USING 1020:C3
1020 IMAGE 10D.2D," COST OF EQUITY"
1030 PRINT @40: USING 1040:F1
1040 IMAGE 8D.4D," FRACTION DEBT FINANCED"
1050 PRINT @40: USING 1060:L1
1060 IMAGE 10D.2D," PLANT LIFE - YEARS"
1070 PRINT @40: USING 1080:T1
1080 IMAGE 8D.4D," TAX RATE"
1090 REM
1100 REM----------------------------------------SECTION 4
1110 REM  PROGRAM BODY-INITIAL CALCULATIONS,1 OUTPUT
1120 C4=F1*C2+(1-F1)*C3
1130 I1=0
1140 B3=0
1150 B5=0
1160 Y5=3
1170 B2=P1/Y5
1180 FOR K=1 TO Y5
1190 B3=B3+B2
1200 B5(K)=B3*F1*C4
1210 I1=I1+B5(K)
1220 NEXT K
1230 C5=P1+I1
1240 PRINT @40: USING 1250:C5
1250 IMAGE 10D.2D," TOTAL DEPRECIABLE PLANT"
1260 D1=C5*F1
1270 Y1=C5*(1-F1)
1280 D2=D1/L1
1290 Y2=Y1/L1
1300 D3=C5/L1
1310 I4=0
1320 D5=0
1330 I2=0
1340 R3=0
1350 V2=C4*(1+C4)^L1/((1+C4)^L1-1)
1360 REM
1370 REM----------------------------------------SECTION 5
```

```
1370 REM---------------------------------------SECTION 5
1380 REM  PROGRAM BODY-DETAILED CALCULATIONS
1390 FOR J=1 TO L1
1400 D5(J)=D1*(1-(J-1)/L1)
1410 I2(J)=D5(J)*C2
1420 I4=I4+I2(J)
1430 Y3(J)=Y1*(1-(J-1)/L1)
1440 Y4(J)=Y3(J)*C3
1450 IF J=T4 THEN 1480
1460 X1(J)=D3+I2(J)+C1
1470 GO TO 1490
1480 X1(J)=D3+I2(J)+C1+E2
1490 R1(J)=(Y4(J)+X1(J)*(1-T1))/(1-T1)
1500 T2(J)=T1*(R1(J)-X1(J))
1510 V1(J)=1/(1+C4)^J
1520 R2(J)=V1(J)*R1(J)
1530 A1(J)=R1(J)/Q1
1540 R3=R3+R2(J)
1550 NEXT J
1560 R4=V2*R3
1570 R5=R4/Q1
1580 REM
1590 REM---------------------------------------SECTION 6
1600 REM  MAIN OUTPUT
1610 REM IF ONLY LEVELIZED COST OF SERVICE DESIRED,SET Y6=0
1620 Y6=0
1630 IF Y6=0 THEN 1830
1640 PRINT @40:"J"
1650 PRINT @40:"  YEAR  DEPRECIATION    DEBT         DEBT ";
1660 PRINT @40:"       EQUITY      EQUITY"
1670 PRINT @40:"                            PAYMENT     INTEREST";
1680 PRINT @40:"      PAYMENT     EARNINGS"
1690 FOR N=1 TO L1
1700 PRINT @40: USING 1710:N,D3,D2,I2(N),Y2,Y4(N)
1710 IMAGE 6D,5(12D)
1720 NEXT N
1730 PRINT @40:"J"
1740 PRINT @40:"  YEAR   EXPENSES       TAXES       REVENUE";
1750 PRINT @40:"    PRESENT       THRUPUT     SERVICE"
1760 PRINT @40:"                                        RREQUIRED";
1770 PRINT @40:"  VALUE RR                    COST"
1780 IMAGE 6D,5(12D),$4D.2D
1790 FOR J=1 TO L1
1800 PRINT @40: USING 1780:J,X1(J),T2(J),R1(J),R2(J),Q1,A1(J)
1810 NEXT J
1820 PRINT @40:"JJ"
1830 PRINT @40: USING 1840:R5
1840 IMAGE $10D.2D," = LEVELIZED COST OF SERVICE"
1850 PRINT @37,26:0
1860 END
```

APPENDIX E. Computer Runs for Economic Analysis of Natural Gas Storage

DEPLETED FIELD, NEW, BASE CASE NATURAL GAS OPERATION

```
13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
14986400.00 TOTAL DEPRECIABLE PLANT
      $0.88 - LEVELIZED COST OF SERVICE
```

2 BASE CASE (B.C.) $2 NAT. GAS

```
16700000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
17104800.00 TOTAL DEPRECIABLE PLANT
      $1.10 - LEVELIZED COST OF SERVICE
```

3 B.C. $3 NAT. GAS

```
20400000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
23337600.00 TOTAL DEPRECIABLE PLANT
      $1.33 - LEVELIZED COST OF SERVICE
```

4 B.C. INVENTORY EXPENSE BASE GAS

```
 9500000.00 ERECTED PLANT COST
  650000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
10868000.00 TOTAL DEPRECIABLE PLANT
      $0.80 = LEVELIZED COST OF SERVICE
```

5 B.C. INV. BASE GAS $2 NAT. GAS

9500000.00	ERECTED PLANT COST
1075000.00	OPERATING COST/YEAR
3080000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
10868000.00	TOTAL DEPRECIABLE PLANT
$0.94	= LEVELIZED COST OF SERVICE

6 B.C. INV. BASE GAS $3 NAT. GAS

9500000.00	ERECTED PLANT COST
1500000.00	OPERATING COST/YEAR
3080000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
10868000.00	TOTAL DEPRECIABLE PLANT
$1.08	= LEVELIZED COST OF SERVICE

7 B.C. 1.3*WELL COST

14600000.00	ERECTED PLANT COST
200000.00	OPERATING COST/YEAR
3080000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
16702400.00	TOTAL DEPRECIABLE PLANT
$0.97	= LEVELIZED COST OF SERVICE

8 B.C. 1.3*COMPRESSION COST

13300000.00	ERECTED PLANT COST
200000.00	OPERATING COST/YEAR
3080000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
15215200.00	TOTAL DEPRECIABLE PLANT
$0.89	= LEVELIZED COST OF SERVICE

```
     9 B.C. 1.3*LINES

13400000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
15329600.00 TOTAL DEPRECIABLE PLANT
      $0.90 - LEVELIZED COST OF SERVICE



    10 B.C. 0.7*LINES

12800000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
14643200.00 TOTAL DEPRECIABLE PLANT
      $0.86   LEVELIZED COST OF SERVICE



     11 B.C. 1.3*TOTAL

16000000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
18304000.00 TOTAL DEPRECIABLE PLANT
      $1.06 = LEVELIZED COST OF SERVICE



     12 B.C. DEBT RATE -5%

13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.05 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
14514800.00 TOTAL DEPRECIABLE PLANT
      $0.7[illegible]   LEVELIZED COST OF SERVICE
```

```
    13 B.C. DEBT RATE =15%

13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.15 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
15458000.00 TOTAL DEPRECIABLE PLANT
       $1.05 = LEVELIZED COST OF SERVICE


    14 B.C. DEBT RATE =20%

13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.20 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
15929600.00 TOTAL DEPRECIABLE PLANT
       $1.24 = LEVELIZED COST OF SERVICE


    15 B.C. DEBT RATE, DEBT FRACTION 0

13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.00 COST OF DEBT
       0.15 COST OF EQUITY
     0.0000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
13100000.00 TOTAL DEPRECIABLE PLANT
       $1.18 = LEVELIZED COST OF SERVICE


    16 B.C. DEBT FRACTION =0.2

13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.2000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
13833600.00 TOTAL DEPRECIABLE PLANT
       $1.09 = LEVELIZED COST OF SERVICE
```

```
    17 B.C. DEBT FRACTION =.5

13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.5000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
14737500.00 TOTAL DEPRECIABLE PLANT
       $0.94 - LEVELIZED COST OF SERVICE
```

```
   18 B.C. DEBT FRACTION = .8

13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.8000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
15405600.00 TOTAL DEPRECIABLE PLANT
       $0.75   LEVELIZED COST OF SERVICE
```

```
    19 B.C. EQUITY RATE  5%

13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.05 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
14357600.00 TOTAL DEPRECIABLE PLANT
       $0.55 - LEVELIZED COST OF SERVICE
```

```
   20 B.C. EQUITY RATE= 10%

13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.10 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
14672000.00 TOTAL DEPRECIABLE PLANT
       $0.71 - LEVELIZED COST OF SERVICE
```

21 B.C. EQUITY RATE = 20%

13100000.00	ERECTED PLANT COST
200000.00	OPERATING COST/YEAR
3080000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.20	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
15300800.00	TOTAL DEPRECIABLE PLANT
$1.06	= LEVELIZED COST OF SERVICE

22 B.C. CONSTRUCTION TIME =1 YEAR

13100000.00	ERECTED PLANT COST
200000.00	OPERATING COST/YEAR
3080000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
14043200.00	TOTAL DEPRECIABLE PLANT
$0.83	= LEVELIZED COST OF SERVICE

23 B.C. CONSTRUCTION TIME =2 YEARS

13100000.00	ERECTED PLANT COST
200000.00	OPERATING COST/YEAR
3080000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
14514800.00	TOTAL DEPRECIABLE PLANT
$0.85	= LEVELIZED COST OF SERVICE

24 B.C. OPERATING COST/2

13100000.00	ERECTED PLANT COST
100000.00	OPERATING COST/YEAR
3080000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
14986400.00	TOTAL DEPRECIABLE PLANT
$0.84	= LEVELIZED COST OF SERVICE

25 B.C. THROUGHPUT HIGHER

```
13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 6000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE    YEARS
     0.4800 TAX RATE
14986400.00 TOTAL DEPRECIABLE PLANT
      $0.45 = LEVELIZED COST OF SERVICE
```

26 B.C. SALVAGE VALUE FOR BASE GAS IN YR. 27

```
13100000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
-3621000.00 EXTRAORDINARY ONE TIME EXPENSE
      27.00 YEAR OF EXTRAORDINARY EXPENSE
 3080000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE    YEARS
     0.4800 TAX RATE
14986400.00 TOTAL DEPRECIABLE PLANT
      $0.[illegible]   LEVELIZED COST OF SERVICE
```

27 B.C. AS CONSTRUCTED

```
 3600000.00 ERECTED PLANT COST
  200000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.05 COST OF DEBT
       0.10 COST OF EQUITY
     0.7500 FRACTION DEBT FINANCED
      27.00 PLANT LIFE    YEARS
     0.4800 TAX RATE
 39[illegible]500.00 TOTAL DEPRECIABLE PLANT
      $0.18   LEVELIZED COST OF SERVICE
```

28 B.C. AS CONSTRUCTED, OPERATING COST CHANGE

```
 3600000.00 ERECTED PLANT COST
   75000.00 OPERATING COST/YEAR
 3080000.00 THRUPUT/YEAR
       0.05 COST OF DEBT
       0.10 COST OF EQUITY
     0.7500 FRACTION DEBT FINANCED
      27.00 PLANT LIFE    YEARS
     0.4800 TAX RATE
 39[illegible]500.00 TOTAL DEPRECIABLE PLANT
      $0.14   LEVELIZED COST OF SERVICE
```

AQUIFER, NATURAL GAS SERVICE, BASE CASE

65100000.00	ERECTED PLANT COST
1200000.00	OPERATING COST/YEAR
6600000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
74474400.00	TOTAL DEPRECIABLE PLANT
$2.07	= LEVELIZED COST OF SERVICE

2 BASE CASE (B.C.), $2 GAS

71500000.00	ERECTED PLANT COST
1200000.00	OPERATING COST/YEAR
6600000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
81796000.00	TOTAL DEPRECIABLE PLANT
$2.25	= LEVELIZED COST OF SERVICE

3 B.C. $3 GAS

87600000.00	ERECTED PLANT COST
1200000.00	OPERATING COST/YEAR
6600000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
100214400.00	TOTAL DEPRECIABLE PLANT
$2.[illegible]2	= LEVELIZED COST OF SERVICE

B.C. INVENTORY EXPENSE NAT. GAS

3[illegible]600000.00	ERECTED PLANT COST
4700000.00	OPERATING COST/YEAR
6600000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
[illegible].00	PLANT LIFE - YEARS
0.4800	TAX RATE
4[illegible]188000.00	TOTAL DEPRECIABLE PLANT
$1.85	LEVELIZED COST OF SERVICE

5 B.C. AQUIFER, INV. EXP. NAT. GAS

```
39500000.00 ERECTED PLANT COST
 5000000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
45188000.00 TOTAL DEPRECIABLE PLANT
       $1.90 - LEVELIZED COST OF SERVICE
```

6 B.C. AQUIFER, INV. EXP. NAT. GAS+.3 GAS

```
39500000.00 ERECTED PLANT COST
 7000000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
45188000.00 TOTAL DEPRECIABLE PLANT
       $2.20 - LEVELIZED COST OF SERVICE
```

7 B.C. 1.3*WELL COST

```
67200000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
76876800.00 TOTAL DEPRECIABLE PLANT
       $2.13 - LEVELIZED COST OF SERVICE
```

8 1.3*COMPRESSION COST

```
66300000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
75847200.00 TOTAL DEPRECIABLE PLANT
       $2.10 - LEVELIZED COST OF SERVICE
```

```
     9 AQUIFER B.C. 1.3*LINES

71130000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
81372720.00 TOTAL DEPRECIABLE PLANT
       $2.24 - LEVELIZED COST OF SERVICE


    10  B.C. 0.7*LINES

59100000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
67610400.00 TOTAL DEPRECIABLE PLANT
       $1.89   LEVELIZED COST OF SERVICE


     11 B.C. 1.3* TOTAL

76900000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
87973600.00 TOTAL DEPRECIABLE PLANT
       $2.41   LEVELIZED COST OF SERVICE


     12 B.C. DEBT RATE  5%

65100000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.05 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
72130800.00 TOTAL DEPRECIABLE PLANT
       $1.69   LEVELIZED COST OF SERVICE
```

13 AQUIFER , B.C., DEBT RATE=15%

65100000.00	ERECTED PLANT COST
1200000.00	OPERATING COST/YEAR
6600000.00	THRUPUT/YEAR
0.15	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE YEARS
0.4800	TAX RATE
76818000.00	TOTAL DEPRECIABLE PLANT
$2.47	= LEVELIZED COST OF SERVICE

14 DEBT RATE - 20%

65100000.00	ERECTED PLANT COST
1200000.00	OPERATING COST/YEAR
6600000.00	THRUPUT/YEAR
0.20	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE YEARS
0.4800	TAX RATE
79161600.00	TOTAL DEPRECIABLE PLANT
$2.90	- LEVELIZED COST OF SERVICE

15 DEBT RATE, DEBT FRACTION =0

65100000.00	ERECTED PLANT COST
1200000.00	OPERATING COST/YEAR
6600000.00	THRUPUT/YEAR
0.00	COST OF DEBT
0.15	COST OF EQUITY
0.0000	FRACTION DEBT FINANCED
27.00	PLANT LIFE YEARS
0.4800	TAX RATE
65100000.00	TOTAL DEPRECIABLE PLANT
$[illegible]	- LEVELIZED COST OF SERVICE

16 DEBT FRACTION 0.[illegible]

65100000.00	ERECTED PLANT COST
1200000.00	OPERATING COST/YEAR
6600000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.2000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
68745600.00	TOTAL DEPRECIABLE PLANT
$2.57	- LEVELIZED COST OF SERVICE

17 DEBT FRACTION =0.5,AQUIFERNAT. GAS

65100000.00 ERECTED PLANT COST
1200000.00 OPERATING COST/YEAR
6600000.00 THRUPUT/YEAR
0.10 COST OF DEBT
0.15 COST OF EQUITY
0.5000 FRACTION DEBT FINANCED
27.00 PLANT LIFE - YEARS
0.4800 TAX RATE
73237500.00 TOTAL DEPRECIABLE PLANT
$2.20 = LEVELIZED COST OF SERVICE

18 DEBT FRACTION =0.8
65100000.00 ERECTED PLANT COST
1200000.00 OPERATING COST/YEAR
6600000.00 THRUPUT/YEAR
0.10 COST OF DEBT
0.15 COST OF EQUITY
0.8000 FRACTION DEBT FINANCED
27.00 PLANT LIFE - YEARS
0.4800 TAX RATE
76557600.00 TOTAL DEPRECIABLE PLANT
$1.77 = LEVELIZED COST OF SERVICE

19 B.C. EQUITY RATE =5%

65100000.00 ERECTED PLANT COST
1200000.00 OPERATING COST/YEAR
6600000.00 THRUPUT/YEAR
0.10 COST OF DEBT
0.05 COST OF EQUITY
0.6000 FRACTION DEBT FINANCED
27.00 PLANT LIFE - YEARS
0.4800 TAX RATE
71349600.00 TOTAL DEPRECIABLE PLANT
$1.31 = LEVELIZED COST OF SERVICE

20 B.C. EQUITY RATE =10%

65100000.00 ERECTED PLANT COST
1200000.00 OPERATING COST/YEAR
6600000.00 THRUPUT/YEAR
0.10 COST OF DEBT
0.10 COST OF EQUITY
0.6000 FRACTION DEBT FINANCED
27.00 PLANT LIFE - YEARS
0.4800 TAX RATE
72912000.00 TOTAL DEPRECIABLE PLANT
$1.67 = LEVELIZED COST OF SERVICE

```
   21 EQUITY RATE =20 %

65100000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.20 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
76036800.00 TOTAL DEPRECIABLE PLANT
      $2.49 = LEVELIZED COST OF SERVICE


   22 B.C. AQUIFER , CONSTRUCTION TIME =1 YEAR

65100000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
69787200.00 TOTAL DEPRECIABLE PLANT
      $1.95 = LEVELIZED COST OF SERVICE


   23 B.C. CONSTRUCTION TIME =2 YEARS

65100000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
72130800.00 TOTAL DEPRECIABLE PLANT
      $2.01 = LEVELIZED COST OF SERVICE


    4 B.C. OPERATING COST/2

65100000.00 ERECTED PLANT COST
  600000.00 OPERATING COST/YEAR
 6600000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
74474400.00 TOTAL DEPRECIABLE PLANT
      $1.92 = LEVELIZED COST OF SERVICE
```

B.C. SALVAGE VALUE FOR BASE GAS IN YEAR 27

```
 65100000.00 ERECTED PLANT COST
  1200000.00 OPERATING COST/YEAR
-25630000.00 EXTRAORDINARY ONE TIME EXPENSE
       27.00 YEAR OF EXTRAORDINARY EXPENSE
  6600000.00 THRUPUT/YEAR
        0.10 COST OF DEBT
        0.15 COST OF EQUITY
      0.6000 FRACTION DEBT FINANCED
       27.00 PLANT LIFE   YEARS
      0.4800 TAX RATE
 74474400.00 TOTAL DEPRECIABLE PLANT
       $2.04 = LEVELIZED COST OF SERVICE
```

26 AS PROPOSED FOR CONSTRUCTION, FINANCING ASSUMED

```
 58500000.00 ERECTED PLANT COST
  1166000.00 OPERATING COST/YEAR
-25630000.00 EXTRAORDINARY ONE TIME EXPENSE
       27.00 YEAR OF EXTRAORDINARY EXPENSE
  6600000.00 THRUPUT/YEAR
        0.10 COST OF DEBT
        0.15 COST OF EQUITY
      0.6000 FRACTION DEBT FINANCED
       27.00 PLANT LIFE   YEAR
      0.4800 TAX RATE
 66924000.00 TOTAL DEPRECIABLE PLANT
       $1.2[illegible] = LEVELIZED COST OF SERVICE
```

SALT DOME NATURAL GAS SERVICE,BASE CASE

17100000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
6200000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
19562400.00	TOTAL DEPRECIABLE PLANT
$0.58	- LEVELIZED COST OF SERVICE

2 BASE CASE(B.C.),$2 NAT. GAS

20800000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
6200000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
23795200.00	TOTAL DEPRECIABLE PLANT
$0.70	- LEVELIZED COST OF SERVICE

3 B.C. $3 NAT GAS

23100000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
6200000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
26426400.00	TOTAL DEPRECIABLE PLANT
$0.77	- LEVELIZED COST OF SERVICE

4 B.C. INVENTORY EXPENSE BASE GAS

16400000.00	ERECTED PLANT COST
450000.00	OPERATING COST/YEAR
6200000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
18761600.00	TOTAL DEPRECIABLE PLANT
$0.58	- LEVELIZED COST OF SERVICE

```
     5 B.C. INV. EXP. BASE GAS,$2 GAS

16400000.00 ERECTED PLANT COST
  850000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18761600.00 TOTAL DEPRECIABLE PLANT
       $0.64 = LEVELIZED COST OF SERVICE


     6 B.C. INV. EXP. BASE GAS,$3 GAS

16400000.00 ERECTED PLANT COST
 1150000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18761600.00 TOTAL DEPRECIABLE PLANT
       $0.69 = LEVELIZED COST OF SERVICE


     7 B.C. 1.3*WELLS

19500000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
22308000.00 TOTAL DEPRECIABLE PLANT
       $0.66 = LEVELIZED COST OF SERVICE


     8 B.C. 1.3*COMPRESSION COST

18900000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
21621600.00 TOTAL DEPRECIABLE PLANT
       $0.64 = LEVELIZED COST OF SERVICE
```

```
      9 B.C. 1.3*LINES

17900000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20477600.00 TOTAL DEPRECIABLE PLANT
      $0.61 = LEVELIZED COST OF SERVICE


      10 B.C. 0.7*LINES

16300000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18647200.00 TOTAL DEPRECIABLE PLANT
      $0.56 = LEVELIZED COST OF SERVICE


      11 B.C. 1.3*TOTAL

22000000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
25168000.00 TOTAL DEPRECIABLE PLANT
      $0.73 - LEVELIZED COST OF SERVICE


      12 B.C. DEBT RATE =5%

1[illegible]100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.05 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
1[illegible]246800.00 TOTAL DEPRECIABLE PLANT
      $0.48 = LEVELIZED COST OF SERVICE
```

```
   13 B.C. DEBT RATE=15%

17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.15 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20178000.00 TOTAL DEPRECIABLE PLANT
      $0.70 - LEVELIZED COST OF SERVICE


   14 B.C. DEBT RATE=20%

17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.20 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      2[illegible].00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20293600.00 TOTAL DEPRECIABLE PLANT
      $0.[illegible] - LEVELIZED COST OF SERVICE


   15 DEBT RATE DEBT FRACTION 0

17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.00 COST OF DEBT
       0.15 COST OF EQUITY
     0.0000 FRACTION DEBT FINANCED
      2[illegible].00 PLANT LIFE - YEARS
     0.4800 TAX RATE
17100000.00 TOTAL DEPRECIABLE PLANT
      $0.78 - LEVELIZED COST OF SERVICE


   16 B.C. DEBT FRACTION =.2

17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.2000 FRACTION DEBT FINANCED
      2[illegible].00 PLANT LIFE - YEARS
     0.4800 TAX RATE
[illegible] TOTAL DEPRECIABLE PLANT
      $0.[illegible]2 - LEVELIZED COST OF SERVICE
```

17 B.C. DEBT FRACTION =.5

```
17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.5000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19237500.00 TOTAL DEPRECIABLE PLANT
      $0.62 = LEVELIZED COST OF SERVICE
```

18 B.C. DEBT FRACTION =.8

```
17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.8000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20109600.00 TOTAL DEPRECIABLE PLANT
      $0.50 = LEVELIZED COST OF SERVICE
```

19 B.C. EQUITY RATE-5%

```
17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.05 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18741600.00 TOTAL DEPRECIABLE PLANT
      $0.37 = LEVELIZED COST OF SERVICE
```

20 B.C. EQUITY RATE-10%

```
17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.10 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19152000.00 TOTAL DEPRECIABLE PLANT
      $0.47 = LEVELIZED COST OF SERVICE
```

```
    21 EQUITY RATE =20%

17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.20 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19972800.00 TOTAL DEPRECIABLE PLANT
      $0.70 = LEVELIZED COST OF SERVICE


    22 B.C. CONSTRUCTION TIME =1 YEAR

17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18331200.00 TOTAL DEPRECIABLE PLANT
      $0.55 - LEVELIZED COST OF SERVICE


    23 B.C. CONSTRUCTION TIME - 2 YEARS

17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18946800.00 TOTAL DEPRECIABLE PLANT
      $0.57 = LEVELIZED COST OF SERVICE


    24 B.C. OPERATING COST/2

17100000.00 ERECTED PLANT COST
  175000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19562400.00 TOTAL DEPRECIABLE PLANT
      $0.55 = LEVELIZED COST OF SERVICE
```

```
   25 SALVAGE VALUE FOR BASE GAS IN YEAR 27

17100000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 -672000.00 EXTRAORDINARY ONE TIME EXPENSE
      27.00 YEAR OF EXTRAORDINARY EXPENSE
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19562400.00 TOTAL DEPRECIABLE PLANT
      $0.58 - LEVELIZED COST OF SERVICE


   26 AS PLANNED OR BUILT, ASSUMED FINANCING, LOW OPERATING COST

16255000.00 ERECTED PLANT COST
  188000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18595720.00 TOTAL DEPRECIABLE PLANT
      $0.53 - LEVELIZED COST OF SERVICE


   27 RUN 26 WITH HIGHER OPERATING COST

16255000.00 ERECTED PLANT COST
  342000.00 OPERATING COST/YEAR
 6200000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18595720.00 TOTAL DEPRECIABLE PLANT
      $0.56 - LEVELIZED COST OF SERVICE
```

EXCAVATED CAVERN NATURAL GAS SERVICE BASE CASE

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
59488000.00	TOTAL DEPRECIABLE PLANT
$1.30	= LEVELIZED COST OF SERVICF

2 BASE CASE(B.C.), $2 NAT. GAS

54000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
61776000.00	TOTAL DEPRECIABLE PLANT
$1.35	= LEVELIZED COST OF SERVICE

3 B.C. $3 NAT. GAS

56000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
64064000.00	TOTAL DEPRECIABLE PLANT
$1.40	= LEVELIZED COST OF SERVICE

4 INV. EXP. BASE GAS, $1 GAS

50000000.00	ERECTED PLANT COST
750000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
57200000.00	TOTAL DEPRECIABLE PLANT
$1.29	= LEVELIZED COST OF SERVICE

```
   5 EX. CAV. INV.EXP. BASE GAS,$2 GAS

50000000.00 ERECTED PLANT COST
 1000000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
57200000.00 TOTAL DEPRECIABLE PLANT
      $1.32 = LEVELIZED COST OF SERVICE


   6 INV. EXP. BASE GAS, $3 GAS

50000000.00 ERECTED PLANT COST
 1200000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
57200000.00 TOTAL DEPRECIABLE PLANT
      $1.34   LEVELIZED COST OF SERVICE


   7 B.C. 1.3*SURFACE EQUIPMENT

53500000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE    YEARS
     0.4800 TAX RATE
61204000.00 TOTAL DEPRECIABLE PLANT
      $1.31 = LEVELIZED COST OF SERVICE


   8 B.C. 0.7*SURFACE EQUIPMENT

52400000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
59945600.00 TOTAL DEPRECIABLE PLANT
      $1.31   LEVELIZED COST OF SERVICE
```

11 B.C. 1.3*TOTAL

67000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
76648000.00	TOTAL DEPRECIABLE PLANT
$1.66	= LEVELIZED COST OF SERVICE

12 B.C. DEBT RATE=5%

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.05	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
57616000.00	TOTAL DEPRECIABLE PLANT
$1.06	= LEVELIZED COST OF SERVICE

13 B.C. DEBT RATE = 15%

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.15	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
61360000.00	TOTAL DEPRECIABLE PLANT
$1.57	= LEVELIZED COST OF SERVICE

14 DEBT RATE = 20 %

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.20	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
63732000.00	TOTAL DEPRECIABLE PLANT
$1.85	= LEVELIZED COST OF SERVICE

15 DEBT RATE, DEBT FRACTION=0

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.00	COST OF DEBT
0.15	COST OF EQUITY
0.0000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
52000000.00	TOTAL DEPRECIABLE PLANT
$1.76	= LEVELIZED COST OF SERVICE

16 DEBT FRACTION=0.2

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.2000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
54912000.00	TOTAL DEPRECIABLE PLANT
$1.63	- LEVELIZED COST OF SERVICE

17 DEBT FRACTION = 0.5

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.5000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
58500000.00	TOTAL DEPRECIABLE PLANT
$1.39	- LEVELIZED COST OF SERVICE

18 DEBT FRACTION =0.8

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUTIY
0.8000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
61152000.00	TOTAL DEPRECIABLE PLANT
$1.11	- LEVELIZED COST OF SERVICE

19 B.C. EQUITY RATE-5%

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.05	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
56992000.00	TOTAL DEPRECIABLE PLANT
$0.80	- LEVELIZED COST OF SERVICE

20 B.C. EQUITY RATE 10%

52000000.00	ERECTED PLANT COST
500000.00	OPERATING COST/YEAR
8000000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.10	COST OF EQUTIY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
58240000.00	TOTAL DEPRECIABLE PLANT
$1.04	- LEVELIZED COST OF SERVICE

```
    21 B.C. EQUITY RATE=20%

52000000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.20 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
60736000.00 TOTAL DEPRECIABLE PLANT
      $1.59 = LEVELIZED COST OF SERVICE


    22 B.C.CONSTRUCTION TIME =1 YEAR

52000000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
55744000.00 TOTAL DEPRECIABLE PLANT
      $1.73 = LEVELIZED COST OF SERVICE


    23 B.C. CONSTRUCTION TIME 2 YEARS

52000000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
57616000.00 TOTAL DEPRECIABLE PLANT
      $1.26 = LEVELIZED COST OF SERVICE


    24 B.C. 2500 FT. EXCAVATION DEPTH

55000000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
62920000.00 TOTAL DEPRECIABLE PLANT
      $1.38 = LEVELIZED COST OF SERVICE
```

```
    25 B.C. 2500 FT. ROCK AND MINER CREDITS

50000000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
57200000.00 TOTAL DEPRECIABLE PLANT
      $1.26 = LEVELIZED COST OF SERVICE



    26 B.C. 4500 FT. EXCAVATION DEPTH

49000000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
56056000.00 TOTAL DEPRECIABLE PLANT
      $1.23 = LEVELIZED COST OF SERVICE


    27 B.C.4500FT. ROCK AND MINER CREDITS

44000000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
50336000.00 TOTAL DEPRECIABLE PLANT
      $1.11 = LEVELIZED COST OF SERVICE


    28 B.C. 3500 FT. WITH ROCK AND MINER CREDITS

47000000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
53768000.00 TOTAL DEPRECIABLE PLANT
      $1.18 = LEVELIZED COST OF SERVICE
```

29 EX. CAV. B.C., OPERATING COST/2

```
52000000.00 ERECTED PLANT COST
  250000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
59488000.00 TOTAL DEPRECIABLE PLANT
      $1.27 = LEVELIZED COST OF SERVICE
```

30 B.C. OPERATING COST*2

```
52000000.00 ERECTED PLANT COST
 1000000.00 OPERATING COST/YEAR
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
59488000.00 TOTAL DEPRECIABLE PLANT
      $1.37 = LEVELIZED COST OF SERVICE
```

31 B.C.,SALVAGE VALUE FOR BASE GAS IN YEAR 27

```
52000000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
-2000000.00 EXTRAORDINARY ONE TIME EXPENSE
      27.00 YEAR OF EXTRAORDINARY EXPENSE
 8000000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
59488000.00 TOTAL DEPRECIABLE PLANT
      $1.30 = LEVELIZED COST OF SERVICE
```

APPENDIX F. Computer Runs for Economic Analysis of Hydrogen Storage

DEPLETED FIELD H2 BASE CASE, TYPE 2 OPERATION

18300000.00	ERECTED PLANT COST
265000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
[illegible]7.00	PLANT LIFE - YEARS
0.4800	TAX RATE
2093[illegible].00	TOTAL DEPRECIABLE PLANT
$[illegible].21	= LEVELIZED COST OF SERVICE

[illegible] B.C. $4 H2

14750000.00	ERECTED PLANT COST
265000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
[illegible].00	PLANT LIFE - YEARS
0.4800	TAX RATE
16[illegible]000.00	TOTAL DEPRECIABLE PLANT
$1.31	[illegible] LEVELIZED COST OF SERVICE

[illegible] $15 H2

[illegible]1400000.00	ERECTED PLANT COST
[illegible]	OPERATING COST/YEAR
1[illegible]0000.00	THRUPUT/YEAR
[illegible].10	COST OF DEBT
[illegible].15	COST OF EQUITY
0.[illegible]000	FRACTION DEBT FINANCED
[illegible]	PLANT LIFE - YEARS
0.4[illegible]00	TAX RATE
[illegible].00	TOTAL DEPRECIABLE PLANT
$1.0[illegible]	[illegible] LEVELIZED COST OF SERVICE

[illegible] INVENTORY EXPENSE BASE H2 GAS

[illegible]600000.00	ERECTED PLANT COST
1[illegible]0000.00	OPERATING COST/YEAR
1[illegible]00000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.[illegible]000	FRACTION DEBT FINANCED
[illegible].00	PLANT LIFE - YEARS
0.[illegible]800	TAX RATE
8[illegible]40[illegible].00	TOTAL DEPRECIABLE PLANT
$1.[illegible]	- LEVELIZED COST OF SERVICE

5 INVENTORY EXPENSE BASE H2 GAS, $4 H2

```
7600000.00 ERECTED PLANT COST
1125000.00 OPERATING COST/YEAR
1700000.00 THRUPUT/YEAR
      0.10 COST OF DEBT
      0.15 COST OF EQUITY
    0.6000 FRACTION DEBT FINANCED
     27.00 PLANT LIFE - YEARS
    0.4800 TAX RATE
8694400.00 TOTAL DEPRECIABLE PLANT
     $1.52 = LEVELIZED COST OF SERVICE
```

6 INVENTORY EXPENSE BASE H2 GAS, $15 H2

```
7600000.00 ERECTED PLANT COST
3480000.00 OPERATING COST/YEAR
1700000.00 THRUPUT/YEAR
      0.10 COST OF DEBT
      0.15 COST OF EQUITY
    0.6000 FRACTION DEBT FINANCED
     27.00 PLANT LIFE - YEARS
    0.4800 TAX RATE
8694400.00 TOTAL DEPRECIABLE PLANT
     $2.70 = LEVELIZED COST OF SERVICE
```

7 B.C. 1.3*WELLS

```
19200000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
21964800.00 TOTAL DEPRECIABLE PLANT
      $2.31 = LEVELIZED COST OF SERVICE
```

8 B.C. 1.3*COMPRESSION COST

```
18900000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
21621600.00 TOTAL DEPRECIABLE PLANT
      $[illegible] = LEVELIZED COST OF SERVICE
```

```
   9 B.C. 1.3*LINES

18600000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
21278400.00 TOTAL DEPRECIABLE PLANT
      $2.25 = LEVELIZED COST OF SERVICE
```

```
   10 B.C. 0.7*LINES

18000000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20592000.00 TOTAL DEPRECIABLE PLANT
      $2.18 = LEVELIZED COST OF SERVICE
```

```
   11 B.C. 1.3*TOTAL

20700000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
23680800.00 TOTAL DEPRECIABLE PLANT
      $2.48 = LEVELIZED COST OF SERVICE
```

```
   DFF. FIELD W/ B.C.,DEBT RATE=5%

18300000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1785000.00 THRUPUT/YEAR
       0.05 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20276400.00 TOTAL DEPRECIABLE PLANT
      $1.72 = LEVELIZED COST OF SERVICE
```

13 DEP FIELD, B.C. DEBT RATE=15%

```
18300000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1785000.00 THRUPUT/YEAR
       0.15 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
21594000.00 TOTAL DEPRECIABLE PLANT
      $2.53   LEVELIZED COST OF SERVICE
```

14 DEBT RATE [illegible]0%

```
18300000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1785000.00 THRUPUT/YEAR
       0.20 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
22[illegible]2800.00 TOTAL DEPRECIABLE PLANT
      $2.[illegible]   LEVELIZED COST OF SERVICE
```

14 B.C. DEBT RATE, DEBT FRACTION 0

```
18300000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1785000.00 THRUPUT/YEAR
       0.00 COST OF DEBT
       0.15 COST OF EQUITY
     0.0000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18300000.00 TOTAL DEPRECIABLE PLANT
      $2.[illegible]   LEVELIZED COST OF SERVICE
```

16 B.C. DEBT FRACTION 0.[illegible]

```
18300000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1785000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.2000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19324800.00 TOTAL DEPRECIABLE PLANT
      $2.63 - LEVELIZED COST OF SERVICE
```

```
    17 DEP FIELD B.C., DEBT FRACTION=0.5

18300000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1785000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.5000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20587500.00 TOTAL DEPRECIABLE PLANT
      $2.25 = LEVELIZED COST OF SERVICE


    18 B.C. DEBT FRACTION=0.8

18300000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1785000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.8000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
21520800.00 TOTAL DEPRECIABLE PLANT
      $1.80 = LEVELIZED COST OF SERVICE


    B.C. EQUITY RATE =5%

18300000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1785000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.05 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20056800.00 TOTAL DEPRECIABLE PLANT
      $1.32 = LEVELIZED COST OF SERVICE


    20 B.C. EQUITY RATE   10%

18300000.00 ERECTED PLANT COST
  265000.00 OPERATING COST/YEAR
 1785000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.10 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20496000.00 TOTAL DEPRECIABLE PLANT
      $1.69 = LEVELIZED COST OF SERVICE
```

21 B.C. EQUITY RATE =20%

18300000.00	ERECTED PLANT COST
265000.00	OPERATING COST/YEAR
1785000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.20	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE YEARS
0.4800	TAX RATE
21374400.00	TOTAL DEPRECIABLE PLANT
$2.55	- LEVELIZED COST OF SERVICE

B.C. CONSTRUCTION TIME 1 YEAR

18300000.00	ERECTED PLANT COST
265000.00	OPERATING COST/YEAR
1785000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
19617600.00	TOTAL DEPRECIABLE PLANT
$1.98	LEVELIZED COST OF SERVICE

23 B.C. CONSTRUCTION TIME 2 YEARS

18300000.00	ERECTED PLANT COST
265000.00	OPERATING COST/YEAR
1785000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE YEARS
0.4800	TAX RATE
20276400.00	TOTAL DEPRECIABLE PLANT
$2.04	LEVELIZED COST OF SERVICE

24 B.C. OPERATING COST/2

18300000.00	ERECTED PLANT COST
130000.00	OPERATING COST/YEAR
1785000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
20935200.00	TOTAL DEPRECIABLE PLANT
$2.03	- LEVELIZED COST OF SERVICE

25 B.C SALVAGE VALUE FOR BASE GAS IN YEAR 27

18300000.00	ERECTED PLANT COST
265000.00	OPERATING COST/YEAR
-10700000.00	EXTRAORDINARY ONE TIME EXPENSE
27.00	YEAR OF EXTRAORDINARY EXPENSE
1785000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE YEARS
0.4800	TAX RATE
20935200.00	TOTAL DEPRECIABLE PLANT
$2.07	= LEVELIZED COST OF SERVICE

```
    1 DEPLETED FIELD H2 OPERATION TYPE 3 BASE CASE

17300000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19791200.00 TOTAL DEPRECIABLE PLANT
      $1.51 = LEVELIZED COST OF SERVICE


    2 B.C.,$4 H2

15100000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
1[illegible]4400.00 TOTAL DEPRECIABLE PLANT
      $1.35   LEVELIZED COST OF SERVICE


    3 B.C.,$15 H2

27300000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
31231200.00 TOTAL DEPRECIABLE PLANT
      $2.31   LEVELIZED COST OF SERVICE


    4 B.C., INVENTORY EXPENSE H2 BASE GAS

10700000.00 ERECTED PLANT COST
 1080000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
12240800.00 TOTAL DEPRECIABLE PLANT
      $1.31   LEVELIZED COST OF SERVICE
```

5 INVENTORY EXPENSE H2 BASE GAS,$4 H2

10700000.00	ERECTED PLANT COST
815000.00	OPERATING COST/YEAR
2380000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
12240800.00	TOTAL DEPRECIABLE PLANT
$1.20	= LEVELIZED COST OF SERVICE

6 INV. EXP. H2 BASE GAS,$15 H2

10700000.00	ERECTED PLANT COST
2274000.00	OPERATING COST/YEAR
2380000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
12240800.00	TOTAL DEPRECIABLE PLANT
$1.81	= LEVELIZED COST OF SERVICE

7 B.C., 1.3*WELLS

18600000.00	ERECTED PLANT COST
285000.00	OPERATING COST/YEAR
2380000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
21278400.00	TOTAL DEPRECIABLE PLANT
$1.61	= LEVELIZED COST OF SERVICE

8 B.C., 1.3*COMPRESSION COST

18100000.00	ERECTED PLANT COST
285000.00	OPERATING COST/YEAR
2380000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
20706400.00	TOTAL DEPRECIABLE PLANT
$1.57	= LEVELIZED COST OF SERVICE

```
   9 B.C., 1.3*LINES

17600000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20134400.00 TOTAL DEPRECIABLE PLANT
      $1.53 = LEVELIZED COST OF SERVICE


   10 B.C.,0.7*LINES

17000000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19448000.00 TOTAL DEPRECIABLE PLANT
      $1.48 = LEVELIZED COST OF SERVICE


   11 B.C.,1.3*TOTAL

[illegible] ERECTED PLANT COST
[illegible] OPERATING COST/YEAR
[illegible] THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
[illegible] TOTAL DEPRECIABLE PLANT
$1.[illegible] - LEVELIZED COST OF SERVICE


   12 B.C., DEBT RATE =5%

[illegible] ERECTED PLANT COST
[illegible] OPERATING COST/YEAR
[illegible] THRUPUT/YEAR
       0.05 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
[illegible] TOTAL DEPRECIABLE PLANT
      $1.23 - LEVELIZED COST OF SERVICE
```

13 DEPLETED FIELD H2 TYPE 3,DEBT RATE =15%

17300000.00	ERECTED PLANT COST
285000.00	OPERATING COST/YEAR
2380000.00	THRUPUT/YEAR
0.15	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
20414000.00	TOTAL DEPRECIABLE PLANT
$1.81	= LEVELIZED COST OF SERVICE

14 DEBT RATE=20%

17300000.00	ERECTED PLANT COST
285000.00	OPERATING COST/YEAR
2380000.00	THRUPUT/YEAR
0.20	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
21036800.00	TOTAL DEPRECIABLE PLANT
$2.12	- LEVELIZED COST OF SERVICE

15 DEBT RATE -0,DEBT FRACTION-0

17300000.00	ERECTED PLANT COST
285000.00	OPERATING COST/YEAR
2380000.00	THRUPUT/YEAR
0.00	COST OF DEBT
0.15	COST OF EQUITY
0.0000	FRACTION DEBT FINANCED
27.00	PLANT LIFE YEARS
0.4800	TAX RATE
17300000.00	TOTAL DEPRECIABLE PLANT
$2.02	- LEVELIZED COST OF SERVICE

16 DEBT FRACTION =0.2

17300000.00	ERECTED PLANT COST
285000.00	OPERATING COST/YEAR
2380000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.2000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
18263900.00	TOTAL DEPRECIABLE PLANT
$1.88	- LEVELIZED COST OF SERVICE

```
   17 DEBT FRACTION=0.5

17300000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.5000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19462500.00 TOTAL DEPRECIABLE PLANT
      $1.61 - LEVELIZED COST OF SERVICE


   18 DEBT FRACTION=0.8

17300000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.8000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
[illegible] TOTAL DEPRECIABLE PLANT
      $1.29 - LEVELIZED COST OF SERVICE


   19 R.E. EQUITY RATE =5%

17300000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.05 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
[illegible] PLANT LIFE - YEARS
     0.4800 TAX RATE
[illegible] TOTAL DEPRECIABLE PLANT
      $0.95 - LEVELIZED COST OF SERVICE


   20 R.E. EQUITY RATE=10%

17300000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.10 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
[illegible] TOTAL DEPRECIABLE PLANT
      $1.22 - LEVELIZED COST OF SERVICE
```

21 B.C. EQUITY RATE =20%

```
17300000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.20 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
20206400.00 TOTAL DEPRECIABLE PLANT
       $1.82 = LEVELIZED COST OF SERVICE
```

22 CONSTRUCTION TIME =1 YEAR

```
17300000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18545600.00 TOTAL DEPRECIABLE PLANT
       $1.4  = LEVELIZED COST OF SERVICE
```

23 CONSTRUCTION TIME =2YEARS

```
17300000.00 ERECTED PLANT COST
  285000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19168400.00 TOTAL DEPRECIABLE PLANT
       $1.46 = LEVELIZED COST OF SERVICE
```

24 B.C. OPERATING COST/2, DEP. FIELD H2,TYPE 3

```
17300000.00 ERECTED PLANT COST
  140000.00 OPERATING COST/YEAR
 2380000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
19791200.00 TOTAL DEPRECIABLE PLANT
       $1.45 = LEVELIZED COST OF SERVICE
```

25 B.C. SALVAGE VALUE FOR H2 BASE GAS IN YR. 27

17300000.00	ERECTED PLANT COST
285000.00	OPERATING COST/YEAR
-6630000.00	EXTRAORDINARY ONE TIME EXPENSE
27.00	YEAR OF EXTRAORDINARY EXPENSE
2380000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
19791200.00	TOTAL DEPRECIABLE PLANT
$1.49	= LEVELIZED COST OF SERVICE

AQUIFER H2 BASE CASE $6 H2 COST

53300000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
60975[illegible]00.00	TOTAL DEPRECIABLE PLANT
$6.59	- LEVELIZED COST OF SERVICE

2 BASE CASE ,$4H2

46200000.00	ERECTED PLANT COST
10[illegible]5000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.5000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
52852800.00	TOTAL DEPRECIABLE PLANT
[illegible]	- LEVELIZED COST OF SERVICE

3 B.[illegible] $15 H2

84500000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.5000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
96658000.00	TOTAL DEPRECIABLE PLANT
$10.09	- LEVELIZED COST OF SERVICE

4 [illegible] INVENTORY EXPENSE H2 BASE GAS

31[illegible]00000.00	ERECTED PLANT COST
445[illegible].00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
3647[illegible]00.00	TOTAL DEPRECIABLE PLANT
[illegible]	- LEVELIZED COST OF SERVICE

```
   5 INV. EXP. BASE H2 GAS,$4 H2

31900000.00 ERECTED PLANT COST
 2810000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
36493600.00 TOTAL DEPRECIABLE PLANT
      $5.24 = LEVELIZED COST OF SERVICE


   6 INV EXP. BASE GAS, $15 H2

31900000.00 ERECTED PLANT COST
 7451000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
36493600.00 TOTAL DEPRECIABLE PLANT
      $7.97 - LEVELIZED COST OF SERVICE


   7 B.C. 1.3*WELL COST

54000000.00 ERECTED PLANT COST
 1025000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
61776000.00 TOTAL DEPRECIABLE PLANT
      $6.6[illegible]   LEVELIZED COST OF SERVICE


   8 B.C. 1.3*COMPRESSION COST

53600000.00 ERECTED PLANT COST
 1025000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
61318400.00 TOTAL DEPRECIABLE PLANT
      $6.62   LEVELIZED COST OF SERVICE
```

9 B.C. 1.3*LINE COST

59200000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
67724800.00	TOTAL DEPRECTABLE PLANT
$7.25	= LEVELIZED COST OF SERVICE

10 B.C.0.7*LINE COST

47400000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
54225600.00	TOTAL DEPRECIABLE PLANT
$5.93	= LEVELIZED COST OF SERVICE

11 B.C. 1.3*TOTAL

62900000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
71957600.00	TOTAL DEPRECIABLE PLANT
$7.67	= LEVELIZED COST OF SERVICE

12 B.C. DEBT RATE-5%

53300000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.05	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
59056400.00	TOTAL DEPRECIABLE PLANT
$5.41	= LEVELIZED COST OF SERVICE

13 B.C. DEBT RATE = 15%

```
53300000.00 ERECTED PLANT COST
 1025000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.15 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
62894000.00 TOTAL DEPRECIABLE PLANT
      $7.87 = LEVELIZED COST OF SERVICE
```

14 B.C. DEBT RATE =20%

```
53300000.00 ERECTED PLANT COST
 1025000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.20 COST OF DEBT
       0.15 COST OF EQUITY
     0.7000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
64812800.00 TOTAL DEPRECIABLE PLANT
      $7.25   LEVELIZED COST OF SERVICE
```

15 DEBT RATE, DEBT FRACTION =0

```
53300000.00 ERECTED PLANT COST
 1025000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
  [illegible] COST OF DEBT
       0.15 COST OF EQUITY
     0.0000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
[illegible] TOTAL DEPRECIABLE PLANT
  [illegible]   LEVELIZED COST OF SERVICE
```

16 DEBT FRACTION =.2

```
53300000.00 ERECTED PLANT COST
 1025000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.2000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
56284800.00 TOTAL DEPRECIABLE PLANT
      $8.13   LEVELIZED COST OF SERVICE
```

17 B.C. DEBT FRACTION =.5

53300000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.5000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
59962500.00	TOTAL DEPRECIABLE PLANT
$7.03	= LEVELIZED COST OF SERVICE

18 B.C. DEBT FRACTION =0.8

53300000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.8000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
62680800.00	TOTAL DEPRECIABLE PLANT
$5.66	= LEVELIZED COST OF SERVICE

19 B.C. EQUITY RATE=5%

53300000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.05	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
58416800.00	TOTAL DEPRECIABLE PLANT
$4.18	= LEVELIZED COST OF SERVICE

20 B.C. EQUITY RATE=10%

53300000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.10	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
59696000.00	TOTAL DEPRECIABLE PLANT
$5.33	= LEVELIZED COST OF SERVICE

21 B.C. EQUITY RATE =20%

```
53300000.00 ERECTED PLANT COST
 1025000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.20 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
62254400.00 TOTAL DEPRECIABLE PLANT
      $7.95 = LEVELIZED COST OF SERVICE
```

22 B.C. CONSTRUCTION TIME=1 YEAR

```
53300000.00 ERECTED PLANT COST
 1025000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
57137600.00 TOTAL DEPRECIABLE PLANT
      $6.21 = LEVELIZED COST OF SERVICE
```

23 B.C. CONSTRUCTION TIME=2 YEARS

```
53300000.00 ERECTED PLANT COST
 1025000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
59056400.00 TOTAL DEPRECIABLE PLANT



      $6.40 = LEVELIZED COST OF SERVICE
```

24 B.C. OPERATING COST/2

```
53300000.00 ERECTED PLANT COST
  500000.00 OPERATING COST/YEAR
 1700000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
60975200.00 TOTAL DEPRECIABLE PLANT
      $6.28 = LEVELIZED COST OF SERVICE
```

25 B.C. SALVAGE BASE GAS IN YEAR 27

53300000.00	ERECTED PLANT COST
1025000.00	OPERATING COST/YEAR
-21420000.00	EXTRAORDINARY ONE TIME EXPENSE
27.00	YEAR OF EXTRAORDINARY EXPENSE
1700000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
60975200.00	TOTAL DEPRECIABLE PLANT
$6.52	= LEVELIZED COST OF SERVICE

```
   SALT DOME H2 STORAGE BASE CASE (B.C.)

21000000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 1438000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
24024000.00 TOTAL DEPRECIABLE PLANT
       $3.03 = LEVELIZED COST OF SERVICE
```

```
   B.C.,$4 H2COST

19500000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 1438000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
22308000.00 TOTAL DEPRECIABLE PLANT
       $2.83 = LEVELIZED COST OF SERVICE
```

```
   3 B.C. $15 H2 COST

28000000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 1438000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
32032000.00 TOTAL DEPRECIABLE PLANT
       $3.96 = LEVELIZED COST OF SERVICE
```

```
   4 B.C. INVENTORY EXPENSE BASE GAS

16400000.00 ERECTED PLANT COST
  910000.00 OPERATING COST/YEAR
 1438000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18761600.00 TOTAL DEPRECIABLE PLANT
       $2.81 = LEVELIZED COST OF SERVICE
```

```
   5 B.C. INVENTORY EXPENSE BASE GAS, $4 H2

16400000.00 ERECTED PLANT COST
  720000.00 OPERATING COST/YEAR
 1438000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18761600.00 TOTAL DEPRECIABLE PLANT
       $2.68 = LEVELIZED COST OF SERVICE


   6 INVENTORY EXPENSE BASE GAS $15 H2

16400000.00 ERECTED PLANT COST
 1750000.00 OPERATING COST/YEAR
 1438000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
18761600.00 TOTAL DEPRECIABLE PLANT
       $3.39 = LEVELIZED COST OF SERVICE


   7 B.C., 1.3*WELLS

23500000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 1438000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
26884000.00 TOTAL DEPRECIABLE PLANT
       $3.36 - LEVELIZED COST OF SERVICE


   8 B.C. 1.3*COMPRESSION COST

22900000.00 ERECTED PLANT COST
  350000.00 OPERATING COST/YEAR
 1438000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
26197600.00 TOTAL DEPRECIABLE PLANT
       $3.28 = LEVELIZED COST OF SERVICE
```

9 B.C. 1.3*LINES, SALT DOME H2

21900000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
25053600.00	TOTAL DEPRECIABLE PLANT
$3.15	= LEVELIZED COST OF SERVICE

10 B.C., 0.7*LINES

20300000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
23223[illegible]00.00	TOTAL DEPRECIABLE PLANT
$2.94	= LEVELIZED COST OF SERVICE

11 B.C., 1.3*TOTAL

26000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
[illegible]744000.00	TOTAL DEPRECIABLE PLANT
$3.[illegible]0	= LEVELIZED COST OF SERVICE

12 B.C., DEBT RATE=5%

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.05	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
23268000.00	TOTAL DEPRECIABLE PLANT
$2.48	= LEVELIZED COST OF SERVICE

13 B.C., DEBT RATE=15%

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.15	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
24780000.00	TOTAL DEPRECIABLE PLANT
$3.63	- LEVELIZED COST OF SERVICE

14 B.C., DEBT RATE=20%

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.20	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
25536000.00	TOTAL DEPRECIABLE PLANT
$4.27	- LEVELIZED COST OF SERVICE

15 B.C., DEBT RATE=0,DEBT FRACTION =0

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.00	COST OF DEBT
0.15	COST OF EQUITY
0.0000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
21000000.00	TOTAL DEPRECIABLE PLANT
$4.06	= LEVELIZED COST OF SERVICE

16 B.C., DEBT FRACTION=0.2

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.2000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
22176000.00	TOTAL DEPRECIABLE PLANT
$3.77	- LEVELIZED COST OF SERVICE

17 B.C., DEBT FRACTION=0.5

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.5000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
23625000.00	TOTAL DEPRECIABLE PLANT
$3.24	= LEVELIZED COST OF SERVICE

18 B.C., DEBT FRACTION=.8

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.8000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
24696000.00	TOTAL DEPRECIABLE PLANT
$2.60	= LEVELIZED COST OF SERVICE

19 EQUITY RATE 5%,B.C.

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.05	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
23016000.00	TOTAL DEPRECIABLE PLANT
$1.91	= LEVELIZED COST OF SERVICE

20 EQUITY RATE 10%, B.C.

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.10	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
23520000.00	TOTAL DEPRECIABLE PLANT
$2.44	= LEVELIZED COST OF SERVICE

21 B.C., EQUITY RATE=20%,SALT DOME H2

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.20	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
24528000.00	TOTAL DEPRECIABLE PLANT
$3.67	= LEVELIZED COST OF SERVICE

22 B.C., CONSTRUCTION TIME=1 YEAR

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
22512000.00	TOTAL DEPRECIABLE PLANT
$2.86	= LEVELIZED COST OF SERVICE

23 B.C., CONSTRUCTION TIME=2 YEARS

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
23268000.00	TOTAL DEPRECIABLE PLANT
$2.94	= LEVELIZED COST OF SERVICE

24 SALT DOME OPERATING COST/2,H2

21000000.00	ERECTED PLANT COST
175000.00	OPERATING COST/YEAR
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
24024000.00	TOTAL DEPRECIABLE PLANT
$2.91	= LEVELIZED COST OF SERVICE

2: SALT DOME H2 BASE GAS SALVAGE IN YEAR 27

21000000.00	ERECTED PLANT COST
350000.00	OPERATING COST/YEAR
-4650000.00	EXTRAORDINARY ONE TIME EXPENSE
27.00	YEAR OF EXTRAORDINARY EXPENSE
1438000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
24024000.00	TOTAL DEPRECIABLE PLANT
$3.01	= LEVELIZED COST OF SERVICE

EXCAVATED CAVERN BASE CASE H2

53750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
61490000.00	TOTAL DEPRECIABLE PLANT
$5.27	= LEVELIZED COST OF SERVICE

2 R.C. $4 H2

52500000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
60060000.00	TOTAL DEPRECIABLE PLANT
$5.15	= LEVELIZED COST OF SERVICE

3 R.C. $15 H2

59400000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE YEARS
0.4800	TAX RATE
67953600.00	TOTAL DEPRECIABLE PLANT
$5.80	- LEVELIZED COST OF SERVICE

$ R.C. INVENTORY EXPENSE H2 BASE GAS

50000000.00	ERECTED PLANT COST
875000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
57200000.00	TOTAL DEPRECIABLE PLANT
$5.13	LEVELIZED COST OF SERVICE

```
     5 B.C. EX. CAVERN INV EXPENSE H2 ,$4 H2

50000000.00 ERECTED PLANT COST
  725000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
57200000.00 TOTAL DEPRECIABLE PLANT
      $5.06 = LEVELIZED COST OF SERVICE


     6 B.C. INV EXP. BASE GAS ,H2 $15

50000000.00 ERECTED PLANT COST
 1550000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
57200000.00 TOTAL DEPRECIABLE PLANT
      $5.47 = LEVELIZED COST OF SERVICE


     7 B.C. 1.3*SURFACE EQUIPMENT

55250000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
63206000.00 TOTAL DEPRECIABLE PLANT
      $5.41 = LEVELIZED COST OF SERVICE


     8 B.C. 0.7*SURFACE EQUIPMENT

52250000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
59774000.00 TOTAL DEPRECIABLE PLANT
      $5.12 = LEVELIZED COST OF SERVICE
```

RUNS 9 AND 10 OMITTED FROM ANALYSIS SO THAT SUBSEQUENT NUMBERED RUNS CORRESPOND TO THOSE OF OTHER FIELD TYPES.

```
     11 B.C. 1.3* TOTAL

68750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
78650000.00 TOTAL DEPRECIABLE PLANT
      $6.68 = LEVELIZED COST OF SERVICE
```

```
     12 B.C. DEBT RATE=5%

53750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.05 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
59555000.00 TOTAL DEPRECIABLE PLANT
      $4.27 = LEVELIZED COST OF SERVICE
```

13 B.C. DEBT RATE =15%

53750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.15	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
63425000.00	TOTAL DEPRECIABLE PLANT
$6.35	= LEVELIZED COST OF SERVICE

14 DEBT RATE = 20%

53750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.20	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
65360000.00	TOTAL DEPRECIABLE PLANT
$7.51	= LEVELIZED COST OF SERVICE

15 DEBT RATE, FRACTION DEBT 0

53750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.00	COST OF DEBT
0.15	COST OF EQUITY
0.0000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
53750000.00	TOTAL DEPRECIABLE PLANT
$7.12	= LEVELIZED COST OF SERVICE

16 FRACTION DEBT = 0.2

53750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.2000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
56760000.00	TOTAL DEPRECIABLE PLANT
$6.61	= LEVELIZED COST OF SERVICE

```
17 FRACTION DEBT = 0.5

53750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.5000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
60468750.00 TOTAL DEPRECIABLE PLANT
       $5.63 = LEVELIZED COST OF SERVICE


18 FRACTION DEBT-0.8

53750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.8000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
63210000.00 TOTAL DEPRECIABLE PLANT
       $4.48 = LEVELIZED COST OF SERVICE


19 EQUITY RATE-5%

53750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.05 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
58910000.00 TOTAL DEPRECIABLE PLANT
       $3.23 = LEVELIZED COST OF SERVICE


20 EQUITY RATE - 10%

53750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.10 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
60200000.00 TOTAL DEPRECIABLE PLANT
       $4.20 = LEVELIZED COST OF SERVICE
```

21 EQUITY RATE = 20 %

53750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.20	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
62780000.00	TOTAL DEPRECIABLE PLANT
$6.42	= LEVELIZED COST OF SERVICE

22 B.C. CONSTRUCTION TIME =1 YEAR

53750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
57620000.00	TOTAL DEPRECIABLE PLANT
$4.95	= LEVELIZED COST OF SERVICE

23 B.C. CONSTRUCTION TIME =2 YEARS

53750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
59555000.00	TOTAL DEPRECIABLE PLANT
$5.11	= LEVELIZED COST OF SERVICE

24 2500 FT. DEPTH EXCAVATION BASE CASE

56750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
2150000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
64922000.00	TOTAL DEPRECIABLE PLANT
$5.24	= LEVELIZED COST OF SERVICE

B.C. 2500 FT. WITH ROCK AND MINER CREDITS

```
51750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2150000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE - YEARS
     0.4800 TAX RATE
59202000.00 TOTAL DEPRECIABLE PLANT
      $4.79 = LEVELIZED COST OF SERVICE
```

26 BASE CASE 4500 FT. DEPTH

```
50750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 1940000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
58058000.00 TOTAL DEPRECIABLE PLANT
      $5.21 = LEVELIZED COST OF SERVICE
```

27 B.C. 4500 FT. WITH ROCK AND MINER CREDITS

```
45750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 1940000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
52338000.00 TOTAL DEPRECIABLE PLANT
      $4.72 = LEVELIZED COST OF SERVICE
```

28 BASE CASE 3500 FT. WITH CREDITS

```
48750000.00 ERECTED PLANT COST
  425000.00 OPERATING COST/YEAR
 2030000.00 THRUPUT/YEAR
       0.10 COST OF DEBT
       0.15 COST OF EQUITY
     0.6000 FRACTION DEBT FINANCED
      27.00 PLANT LIFE   YEARS
     0.4800 TAX RATE
55770000.00 TOTAL DEPRECIABLE PLANT
      $4.80 = LEVELIZED COST OF SERVICE
```

B.C. 3500 FT OPERATING COST/2

53750000.00	ERECTED PLANT COST
200000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
61490000.00	TOTAL DEPRECIABLE PLANT
$5.15	= LEVELIZED COST OF SERVICE

B.C. 3500 FT OPERATING COST*2

53750000.00	ERECTED PLANT COST
850000.00	OPERATING COST/YEAR
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
61490000.00	TOTAL DEPRECIABLE PLANT
$5.47	= LEVELIZED COST OF SERVICE

B.C. 3500 FT SALVAGE VALUE FOR BASE GAS IN YR. 27

53750000.00	ERECTED PLANT COST
425000.00	OPERATING COST/YEAR
-3750000.00	EXTRAORDINARY ONE TIME EXPENSE
27.00	YEAR OF EXTRAORDINARY EXPENSE
2030000.00	THRUPUT/YEAR
0.10	COST OF DEBT
0.15	COST OF EQUITY
0.6000	FRACTION DEBT FINANCED
27.00	PLANT LIFE - YEARS
0.4800	TAX RATE
61490000.00	TOTAL DEPRECIABLE PLANT
$5.25	= LEVELIZED COST OF SERVICE