DRAFT

STRATEGIC PLAN FOR ENHANCED GAS RECOVERY

Volume 1 – Program Strategy

JUNE 1978

Department of Energy

PREFACE

This report represents the results of a study performed by the Department of Energy (Energy Technology/Division of OGSIST) over the period from April 1977 to April 1978. The study thus predates the recent compromise on natural gas policy under the proposed National Energy Act and the ongoing technology commercialization readiness review being conducted under the auspices of the Under-Secretary. The study results have undergone only partial review within Energy Technology and are being published at this time to provoke discussion and further consideration within the Department of Energy, by other Federal agencies, and by private industry. Recent developments in the drafting of the National Energy Act and inputs from other recent reviews of the unconventional gas resources (e.g., DOE Commercialization Task Force on Unconventional Gas) will undoubtedly impact the recommended research and development program presented in this draft report, as well as the initiation of complementary DOE programs.

The majority of the empirical research and analysis of the study was conducted under the direction of a working group chaired by the Assistant Director of OGSIST for Oil and Gas. The group included senior-level members from DOE headquarters (Energy Technology/FE). The energy research centers, and national laboratories. Lead responsibility for technical direction, research assessment, and review of results was delegated on the basis of the four major unconventional resource areas as follows:

- Western tight gas basins: Nevada Operations Office of the Bartlesville Energy Research Center
- Geopressured aquifers: Energy Technology/ Geothermal Division
- Methane from coal seams: Energy Technology/Fossil Energy and Morgantown Energy Research Center
- Devonian shales: Energy Technology/Fossil Energy and Morgantown Energy Research Center

DRAFT

The empirical research and quantitative assessment of the unconventional gas resources were conducted by Lewin and Associates, Inc. The establishment of project priorities within the recommended program was directly based on the preferences of key DOE/ET executives as revealed through a comprehensive survey and interview process. Booz, Allen and Hamilton played a major role in the coordination of study activities and the preparation of this draft report. In addition, Booz, Allen and Lewin conducted interviews with over 100 private companies currently active or interested in the unconventional gas resources. Resultant data were then provided to the previously mentioned working group for analysis.

DRAFT

T A B L E O F C O N T E N T S

DRAFT

DRAFT

INDEX OF EXHIBITS

DRAFT

DRAFT

DRAFT

EXECUTIVE SUMMARY

1. THE SITUATION

Natural gas, the nation's second most utilized fuel source, provides over one-quarter of the country's total energy requirements. The demand for natural gas increased significantly in the early 1970's and has remained constantly high at approximately 20 Tcf over the past few years. Domestic capacity to satisfy this demand, however, has declined. The effects of this decline were felt first through periodic curtailments and finally during the winter of 1976-1977 in the form of severe industrial disruption.

This shortfall in domestic natural gas supply is characterized by six salient features:

- Total proved reserves have declined by 24 percent since 1970, from 283 Tcf to 216 Tcf (32 Tcf are in Alaska).
- The ratio of proved reserves to production is at an all-time low, less than 11 to 1—about 9-1/2 to 1 when Alaska is excluded.
- New additions to supply, from new discoveries and extensions of known fields, have replaced only 1 Tcf for every 2.5 Tcf consumed over the last 7 years.
- While exploration in 1976 is three times that of 1970, largely as a result of significant price increases, additions per completed exploratory well have declined 4 Bcf per well in 1970 and 1 Bcf per well in 1976.
- New frontiers (Alaska, deeper waters, deeper wells) could contribute significantly, but finding, producing, and delivering this gas will be costly and will require long lead times.
- Developmental drilling, which supplies 80 percent of additions to reserves, has more than doubled in the past 7 years. However, future plans for developmental drilling are not being renewed because of low exploratory success.

DRAFT

As previously stated, natural gas demand has recently maintained a relatively constant level of 20 Tcf over the last few years. Certain observations about future demand can be made, however, despite difficulties caused by uncertainty over the degree of supply regulation and future constraints and incentives (negative and positive) aimed at gas usage. The observations are:

- The National Energy Plan forecast of domestic gas consumption in 1985 is about 19 Tcf per year. This forecast is based upon the assumption that all the provisions of the plan are implemented—including those that deal with other fuel forms as well.

- It appears likely that this forecast of demand is low, given the changes that energy legislation has undergone to date in Congress.

- Gas demand could stay level (at 20 Tcf) or even increase if difficulties are encountered in increasing coal production, in implementing fuel switching on a large scale, or in encouraging significant conservation measures.

Thus, while domestic conventional gas production is decreasing even in the face of significant price increases during this decade, demand is likely to remain high. This situation portends an ever increasing need for supplemental gas sources. Furthermore, the current gas demand is hindered by price controls, constrained by decreasing supply, characterized by high uncertainty, and limited by moratoria on new gas customers in many areas. An additional secure domestic supply would find an eager market. As an environmentally clean, easily handled energy source, gas could substitute indirectly for imported oil, thus improving the balance of payments and providing a positive benefit on the environmental impact of energy.

2. SEVERAL MAJOR GAS SUPPLY OPTIONS ARE AVAILABLE TO DEPARTMENT OF ENERGY POLICYMAKERS

There are several ways in which the DOE could encourage the production of natural gas. These include the following:

- Stimulating additional gas recovery from unconventional sources. Accelerating the recovery of natural gas from unconventional sources appears to be a feasible target for offsetting a significant portion of the likely shortfall. Comprehensive exploitation of the unconventional resources, however, will be required for significant results.

- Improving the economic incentives for natural gas production. Increased gas prices may have only a limited effect unless they are sufficiently high to stimulate development of new resources.[1]

- Increasing the pace of offshore leasing. Even though off-shore gas represents a major portion of potential undiscovered reserves, it should be recognized that this resource is costly to produce and its recovery is likely to lag while platforms and pipelines are constructed. In addition, a timely leasing program would be essential to achieve production in a reasonable time frame.

- Obtaining gas supplies from outside the contiguous states. This is a costly, though possibly inevitable option. Imports of natural gas from Canada and Mexico are being negotiated on a Btu equivalency with imported fuel oil, \$2.50 to \$3.00 per Mcf. Imported Liquefied Natural Gas (LNG) is being considered at \$4.50 per Mcf. Gas from Alaska is estimated at \$3.50 to \$5.50 per Mcf, delivered.

- Developing technologies for manufacturing synthetic gas. Gasification of coal or heavy crudes will require substantial capital investment and prices of \$4.50 per Mcf or more.

The first option, which addresses the utilization of unconventional gas resource areas as a means of increasing domestic gas production, is the most viable and economical solution to the inevitable near-term gas shortage. Current environmental, economic, technological, and international constraints and barriers restrict the other four options from being highly probable and practical near-term solutions.

---

[1] The more speculative unconventional resources, geopressured aquifers and methane recovery from coal seams, may require gas price levels (or other economic incentives) significantly above the general market prices likely to pertain under the recently proposed National Energy Act provisions in order to stimulate substantive private sector commercial production.

DRAFT

3. POTENTIAL OF UNCONVENTIONAL GAS RESOURCES

The unconventional gas resources depicted in Exhibit 1 can make significant contributions to the national gas supply in both the near and long term. The potential of these resources can be realized at a lower cost than many other supplemental gas sources, and can be unlocked most effectively through a combination of technology development, resource characterization, and economic incentives.

Presently, unconventional resources contribute approximately 1 Tcf per year to domestic production.[1] Exhibit 2 demonstrates that the ultimate potential from these resources at $1.75 per Mcf[2] is approximately 70 Tcf (Base Case).[3] At a gas price of $3.00 per Mcf, however, an intensive Federal-industry cooperative R&D program jointly instituted (Advanced Case)[4] could increase the ultimate recovery to from 200 to 260 Tcf. Approximately 50 Tcf could be recovered by 1990 under the Advanced Case. Exhibit 3 demonstrates that Advanced Case technology could generate approximate annual production of 6 Tcf at $1.75 per Mcf, or 8 Tcf at $3.00 per Mcf by 1990.

In addition, the speculative portions of the unconventional resource areas have potentially large reserves (Exhibit 4) which could prove significant once sufficient

---

1 The primary source for this gas is from tight, blanket gas basins such as the San Juan and Denver Basins.

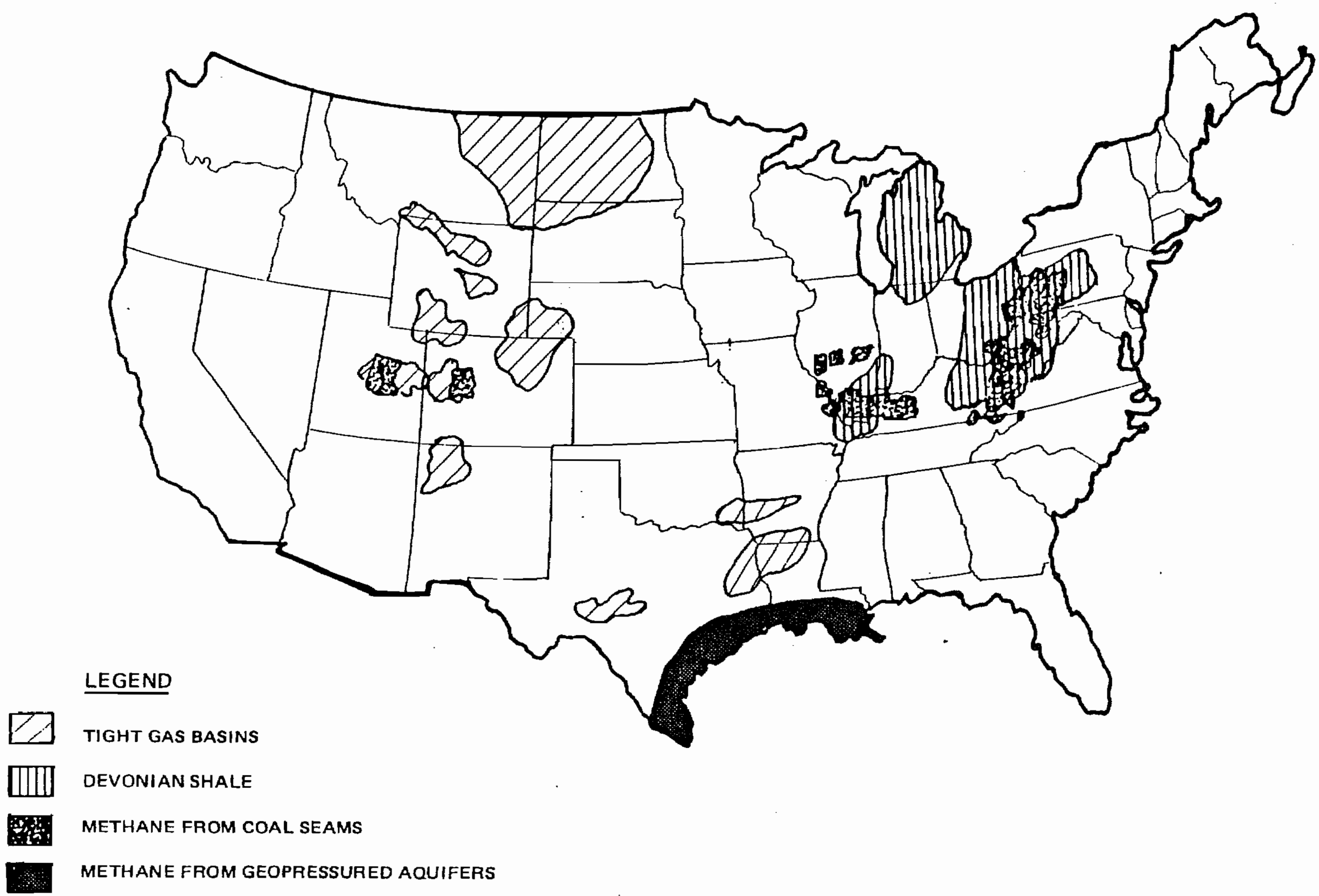
2 Prices are stated in 1977 dollars and assumed maintained in constant dollars through the period of analysis; for example, a $1.75 price under a 6 percent inflation would be $2.75 as expressed in 1985 dollars.

3 The Base Case is defined as expected technological advances and gas production without an accelerated R&D program in enhanced gas recovery.

4 The Advanced Case for unconventional sources includes the Base Case plus additional stimulation by an accelerated Federal R&D program in enhanced gas recovery.

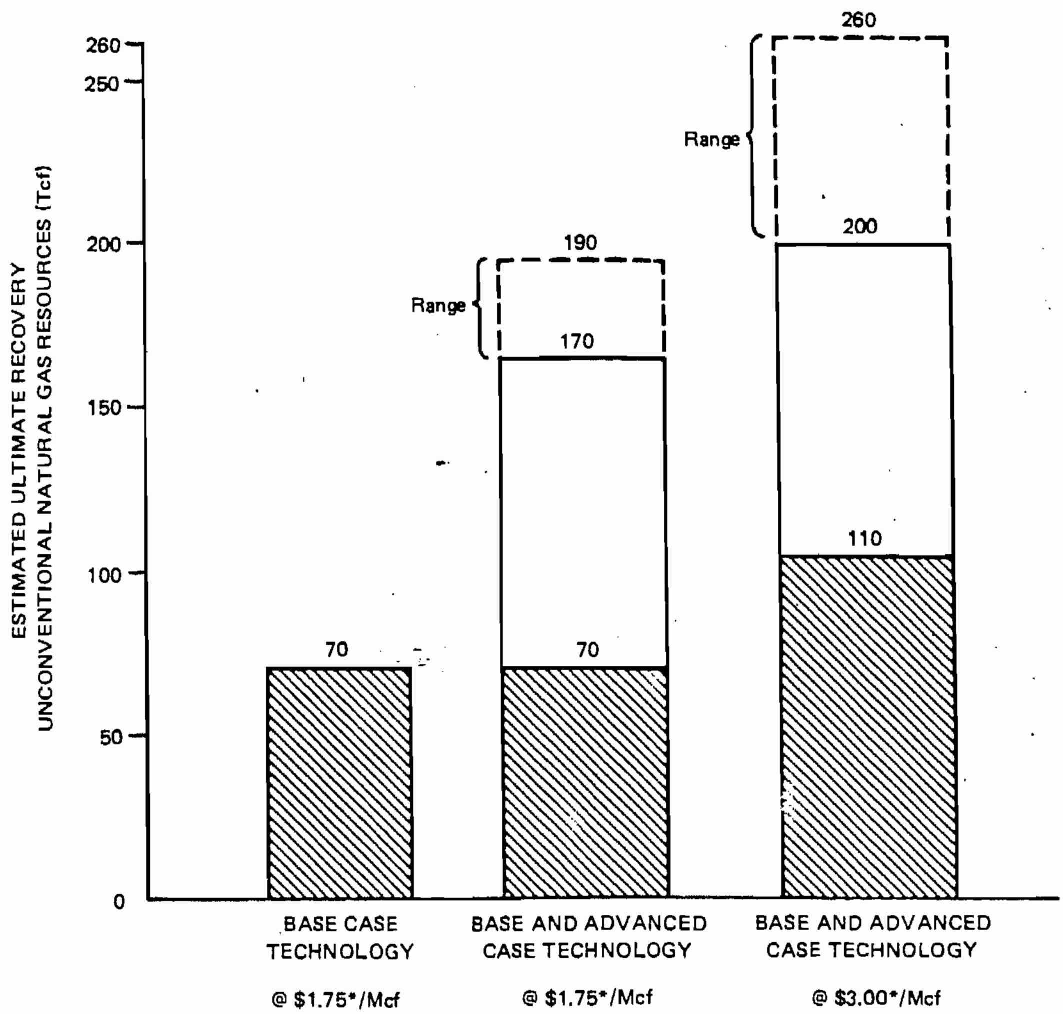
DRAFT

EXHIBIT 1
Location of Unconventional Gas Resources Included in the Analysis



DRAFT

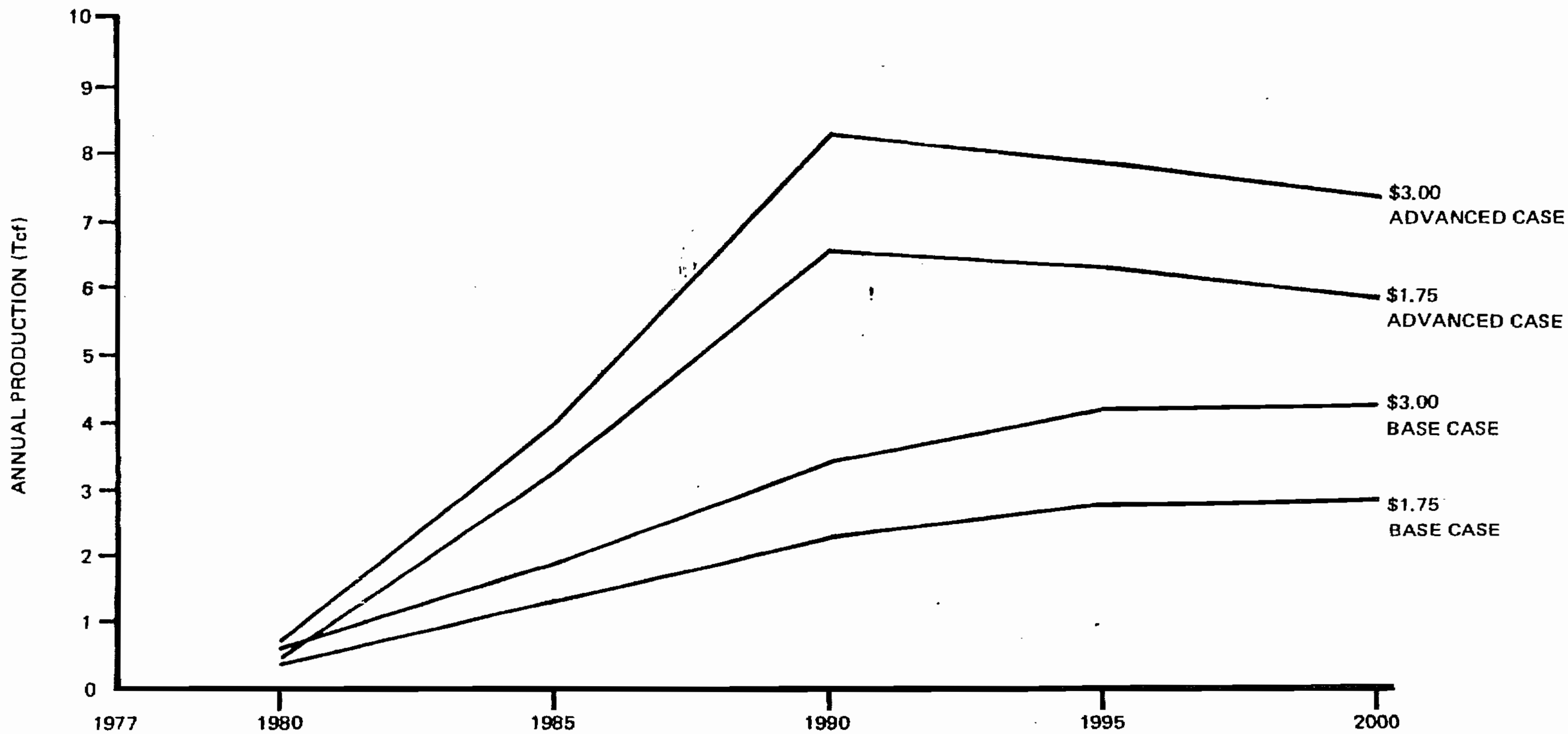
EXHIBIT 2
The Potential of Gas From Unconventional Sources



* IN CONSTANT 1977 DOLLARS

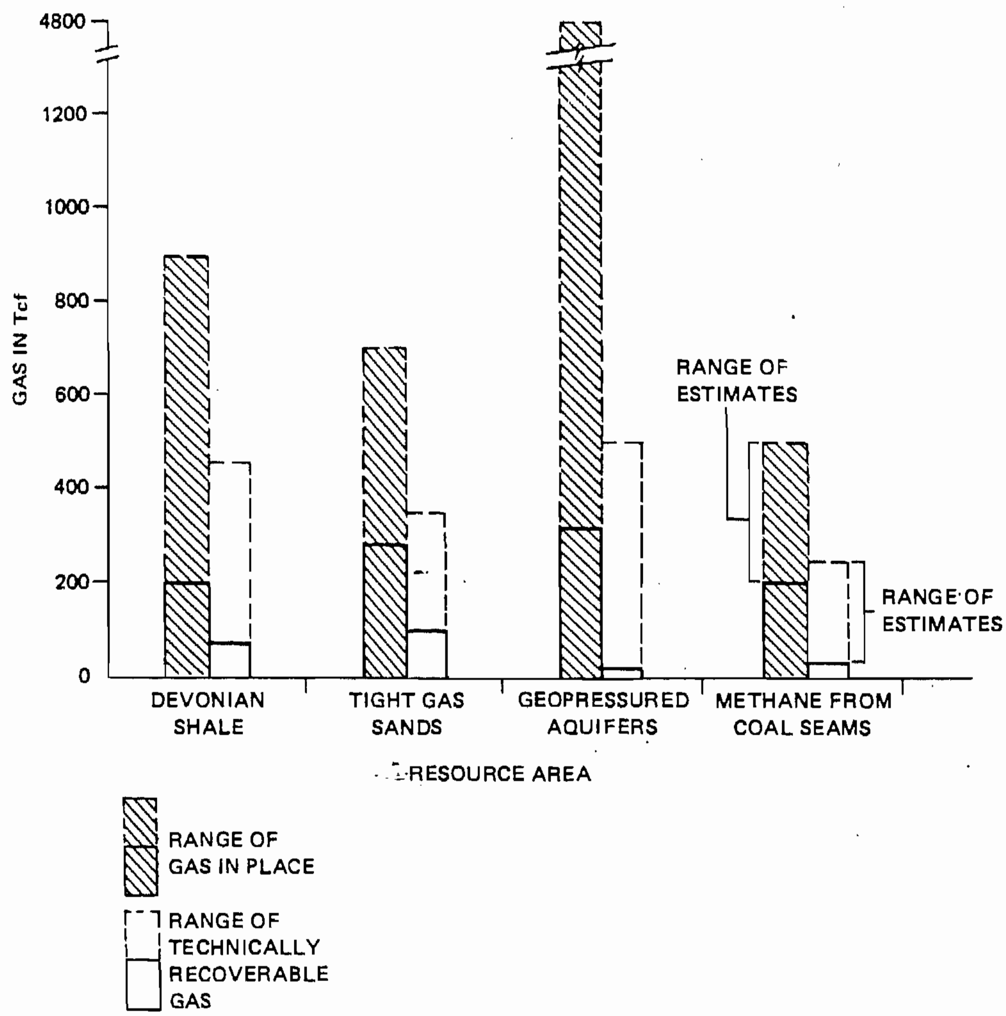
DRAFT

EXHIBIT 3
Annual Production From Unconventional Sources
Base and Advanced Cases at Two Gas Prices



DRAFT

EXHIBIT 4
Range of Estimates of Gas-in-Place and Technically Recoverable Gas From Speculative Areas of Unconventional Resources



[1]The wide range of reserve figures displayed in this Exhibit are "best estimates" of the potential gas-in-place and the gas technically recoverable from these speculative resources. The timing and economic feasibility of recovering these resources are not known.

DRAFT

technical and resource data are available. The best available data on gas-in-place and gas technically recoverable show a wide range of estimates. A federally sponsored program to acquire sufficient resource data to support engineering/economic analyses could significantly improve the accuracy of an assessment of the economic potential of these portions of the unconventional resources.

4. RECOMMENDED DEPARTMENT OF ENERGY ENHANCED GAS RECOVERY RESEARCH AND DEVELOPMENT PROGRAM

The goals, principal technology thrusts, descriptions, and profile analysis of the Enhanced Gas Recovery R&D Program are briefly addressed below.

(1) Goals

While it is anticipated that in the long run, Enhanced Gas Recovery (EGR) techniques will be primarily developed and commercialized by industry, the effective exploitation of the gas resource base in the near term will continue to be constrained by major economic and technological uncertainties. In addition to adequacy of capital and environmental questions, the gas industry is still also hampered by institutional barriers such as price regulations, tax requirements, and the possibility of antitrust action; these factors have tended to dampen the enthusiasm for cooperative ventures.

Thus, an overall, balanced, and coordinated DOE Program in EGR which will help mitigate these economic and technological uncertainties is urgently needed. Within such a program, the R&D portion would make major contributions to the following four primary goals:

- Accelerate the development of an improved scientific, engineering, and economic basis for prompt, orderly development of enhanced recovery technology of the Nation's natural gas resources, over the period from 1985 to 1995. This development centers on improved technologies to recover more of the original gas-in-place. The operating methods to accomplish this goal will represent a combination of laboratory and field tests.

DRAFT

- Accelerate the transfer of DOE-developed technology in EGR to those sectors of private industry that need it in order to accomplish established reserve and production goals or to reduce risk.

- Significantly augment ultimate recoverable gas reserves

  - At $1.75 per Mcf, 82 to 98 Tcf[1]
  - At $3.00 per Mcf, 92 to 152 Tcf[1]

- Significantly increase, over the period from 1985 to 1995, the yearly national gas production from existing reservoirs through the application of EGR technology. A gas industry goal will be 2.0 additional Tcf in 1985, and 4 to 5.5 Tcf in 1990.[1] This goal will require developing a sense of urgency among industrial and governmental participants. Furthermore, a stable economic policy with respect to long-term gas pricing is essential to stimulate production in this high risk area.

(2) <u>Principal Technology Thrusts</u>

The recommended R&D program developed by the analyses and surveys included as elements of this study, encompasses four principal technology thrusts, as follows:

- <u>Target Orientation</u>. The R&D program plan is to exploit the unconventional resource areas with the greatest potential for increasing domestic gas supplied over the period from 1985 to 1995.

- <u>Basic Definition of the Resource Base</u>. The program emphasizes the need for DOE and industry to confirm the geographic area and economic potential of the unconventional resources.

---

[1] These estimates are under the Advanced Case.

DRAFT

- Continuing Research. The program relies on basic research to confirm that each technology associated with the appropriate unconventional resource area has a high probability of success and is compatible with all external factors, such as the environment and economy.

- Field Tests Which Verify Laboratory Investigations. The program calls for a series of field tests to confirm that the basic findings in the laboratory can be extrapolated to actual resource area conditions.

(3) Summary Description of Program

Exhibit 5 presents the recommended 5-year DOE EGR R&D program. Implementation of the full program requires $596.9 million.[1] The program consists of three major components, as follows:

- Group I projects
- Group II projects
- Environmental and Support Activities.

The Group I projects consist of the application of improved technology to the probable and possible areas of the unconventional resources which include discovered and undiscovered reserves. The majority of the 17 Group I projects entail cost-sharing with the private sector. Total DOE costs to implement these projects is $434.1 million over a 5-year period. The corresponding industry costs total $135.9 million. The four Group II projects entail the engineering-geologic characterization of the speculative areas of the undiscovered, unconventional resources. The primary objective of these projects is to obtain the necessary engineering and geologic data to realistically assess the economic recovery potential of such speculative areas. The Group II projects require $108.52 million to implement, and entail 100-percent funding by DOE.

1 Constant 1977 dollars.

DRAFT

EXHIBIT 5

Department of Energy-Comprehensive Research and Development Enhanced Gas Recovery Program

GROUP I PROJECTS

Resource Area	Name	DOE Funding 5 Year Budget (Millions of Constant 1977 $)	DOE Annual Funding (Millions of Constant 1977 $) Year 1	Year 2	Year 3	Year 4	Year 5	Incremental Ultimate Recovery (Tcf@$3/Mcf)	Incremental Annual Production (Tcf in 1985) $1.75/Mcf	$3.00/Mcf	Incremental Annual Production (Tcf in 1990) $1.75/Mcf	$3.00/Mcf	Incremental Annual Production (Tcf in 1995) $1.75/Mcf	$3.00/Mcf
Tight Gas Sands	Tight, Blanket Gas Formations	25.0	5.5	5.5	5.5	5.5	3.0	15.2	0.6	0.4	1.5	1.2	1.2	0.8
Tight Gas Sands	Greater Green River Basin, Full Program	44.7	7.6	9.0	9.0	9.0	10.1	16.7	0.4	0.4	0.8	0.9	0.6	0.7
Tight Gas Sands	Other Tight, Lenticular Sands	17.8	3.4	4.1	4.1	4.1	2.1	8.9	0.1	0.05	0.4	0.2	0.6	0.3
Tight Gas Sands	Uinta Basin, Full Program	44.8	7.6	9.0	9.0	9.0	10.2	15.5	0.5	0.5	0.8	1.0	0.5	0.6
Tight Gas Sands	Piceance Basin, Full Program	29.8	5.0	6.0	6.0	6.0	6.8	8.6	0.1	0.2	0.2	0.5	0.2	0.3
Tight Gas Sands	Other Low-Permeability Reservoirs	6.5	2.2	2.0	0.9	0.9	0.5	5.1	0.0	0.1	0.1	0.3	0.0	0.2
Tight Gas Sands	Shallow, Near Conventional Gas Sands	5.5	1.1	1.2	1.2	1.0	1.0	2.3	0.1	0.1	0.2	0.3	0.05	0.05
Tight Gas Sands	Tight, Shallow Gas Sands	9.3	2.0	2.0	2.0	1.7	1.6	7.6	0.0	0.05	0.0	0.1	0.0	0.2
Tight Gas Sands	Low Permeability, Shallow Gas Sands	6.2	1.3	1.4	1.4	1.1	1.0	1.3	0.0	0.0	0.0	0.0	0.2	0.2
Devonian Shale	Dual Completion of Marginal Devonian Shales, Ohio	29.3	5.9	7.0	6.4	5.3	4.7	6.0	0.1	0.1	0.2	0.3	0.1	0.3
Devonian Shale	Other Devonian Shale Basins	22.4	4.5	5.4	4.9	[illegible]	3.6	[illegible]-7.6	0.0-0.5	0.0-0.1	0.0-0.2	0.0-0.4	0.0-0.2	0.0-0.3
Devonian Shale	Deep Appalachian Front Area	6.5	1.5	1.5	1.5	[illegible]	0.7	[illegible]-4.5	0.0- 0.05	0.0-0.1	0.0-0.1	0.0-0.2	0.0-0.1	0.0-0.2
Devonian Shale	Improve Recovery Efficiency in Productive Devonian Shales	10.0	2.4	2.4	1.9	1.9	1.4	1.7	0.0	0.1	0.0	0.2	0.0	0.1
Devonian Shale	Define Potential of Deep Devonian Shales	25.1	5.8	7.0	5.3	4.0	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Methane From Coal	Methane From Minable Coal-Appalachian Basins	26.2	2.7	4.4	6.5	6.6	6.0	1.6	0.05	0.05	0.05	0.1	0.05	0.1
Methane From Coal	Methane From Unminable Coal-Western Basins	34.1	1.1	4.1	6.2	7.2	5.5	[illegible]	NA	NA	NA	NA	NA	NA
Geopressured Aquifers	Geopressured Aquifers, Full Program	100.9	23.3	25.7	23.3	16.1	12.6	[illegible]	NA	NA	NA	NA	NA	NA
	GROUP I TOTALS	434.1	82.9	97.9	95.6	84.4	73.3	[illegible]	[illegible]	[illegible]-2.25	4.25-4.55	5.1-5.7	3.5-3.8	3.85-4.35

GROUP II PROJECTS

Resource Area	Name	DOE Funding 5 Year Budget (Millions of Constant 1977 $)	DOE Annual Funding (Millions of Constant 1977 $) Year 1	Year 2	Year 3	Year 4	Year 5	Speculative Area (Square Miles)	Gas In Place (Tcf)	Technically Recoverable Gas (Tcf)
Devonian Shales	Characterization of the Speculative Area of the Devonian Shales	27.13	5.43	5.43	5.43	5.43	5.43	[illegible]	[illegible]	80-450
Tight Gas Sands	Characterization of the Speculative Areas of Tight Gas Sands Formation	27.13	5.43	5.43	5.43	5.43	5.43	132,865	[illegible]	[illegible]
Geopressured Aquifers	Characterization of the Speculative Areas of the Geopressured Aquifers	27.13	5.43	5.43	5.43	5.43	5.43	63,000	[illegible]	[illegible]
Methane From Coal	Characterization of the Speculative Areas of Deep Coal Seams	27.13	5.43	5.43	5.43	5.43	5.43	[illegible]	[illegible]	[illegible]
	GROUP II TOTALS	108.52	21.7	21.7	21.7	21.7	21.7	[illegible]	[illegible]	[illegible]

	DOE Funding 5 Year Budget (Millions of Constant 1977 $)	DOE Annual Funding (Millions of Constant 1977 $) Year 1	Year 2	Year 3	Year 4	Year 5
Environmental and Support Services	54.3	10.8	10.8	10.8	10.8	10.8
EGR PROGRAM TOTALS	596.92	115.4	130.4	128.1	116.9	105.8

DRAFT

The environmental and support activities require \$54.3 million over a 5-year period and generally fall into the following four areas:

- Environmental studies and mandated program documents (e.g., Environmental Development Plan)
- Technology transfer[1]
- Expansion of the knowledge base[2]
- General contractor support.

Exhibits 6 and 7 depict the target levels of production and ultimate recovery (at various gas prices) associated with the recommended program. As delineated previously, these goals include an increase in ultimate recoverable gas of 82 to 98 Tcf (at \$1.75), and 92 to 152 Tcf (at \$3.00) above the Base Case and an increase in annual gas production of 2 Tcf above the Base Case by 1985. Prior to focusing on the recommended program in more detail, it is important to emphasize several of the more prominent factors and assumptions upon which the program is based. These include the following:

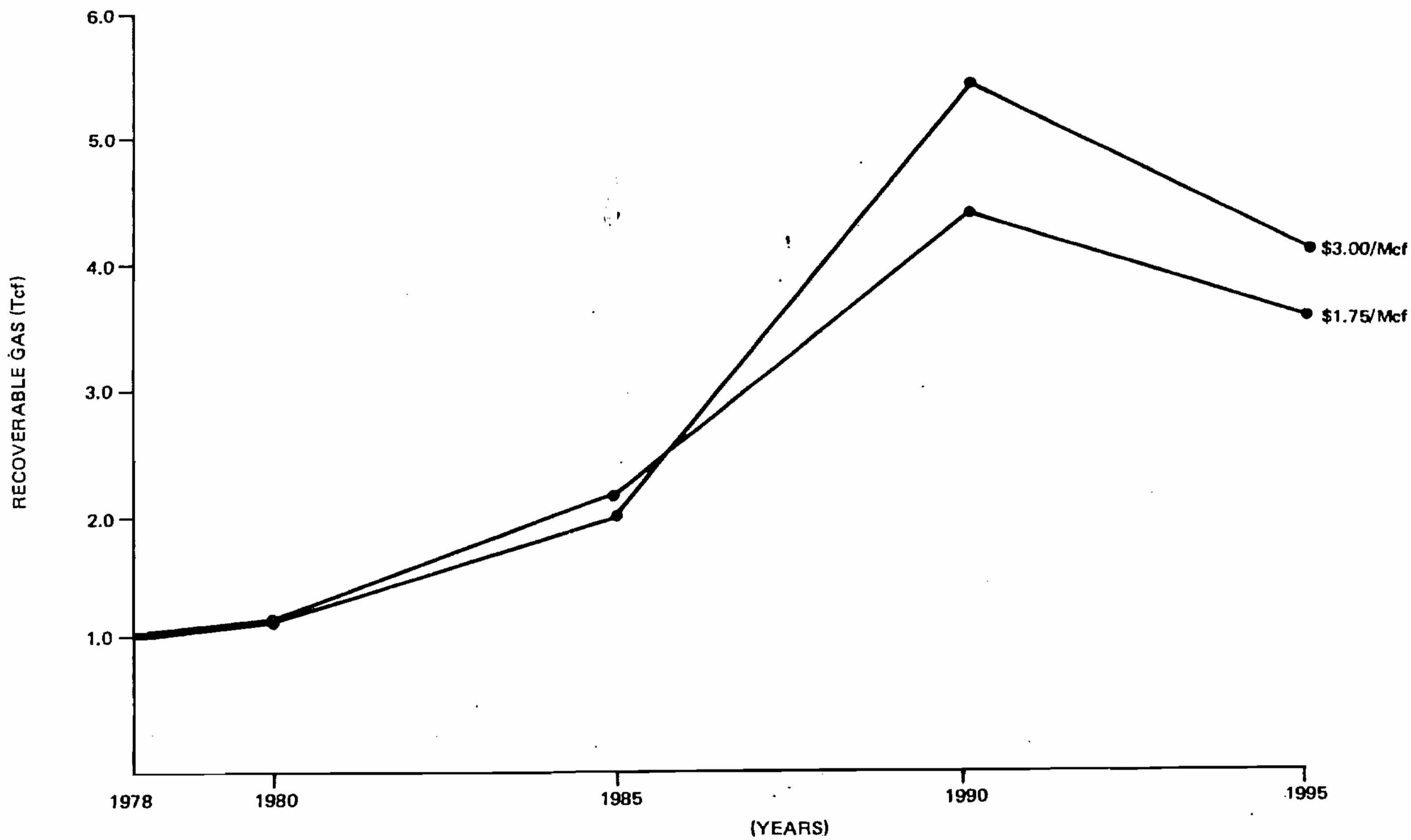
---

1 Each of the individual Group I projects already contains specific technology transfer activities. The technology transfer activities specified here under the heading of "Environmental and Support Activities" relate specifically to DOE Headquarters functions and planning.

2 During the course of the strategic plan development, significant differences of opinion surfaced concerning the potential of certain unconventional resource areas and the ability of alternative technology approaches to economically unlock the resources. The technical uncertainties clearly demonstrated the need for continuing refinement, review, and further investigation in the development of the recommended program. Thus, the recommended 5-year program contains funding for these "knowledge base expansion" activities.

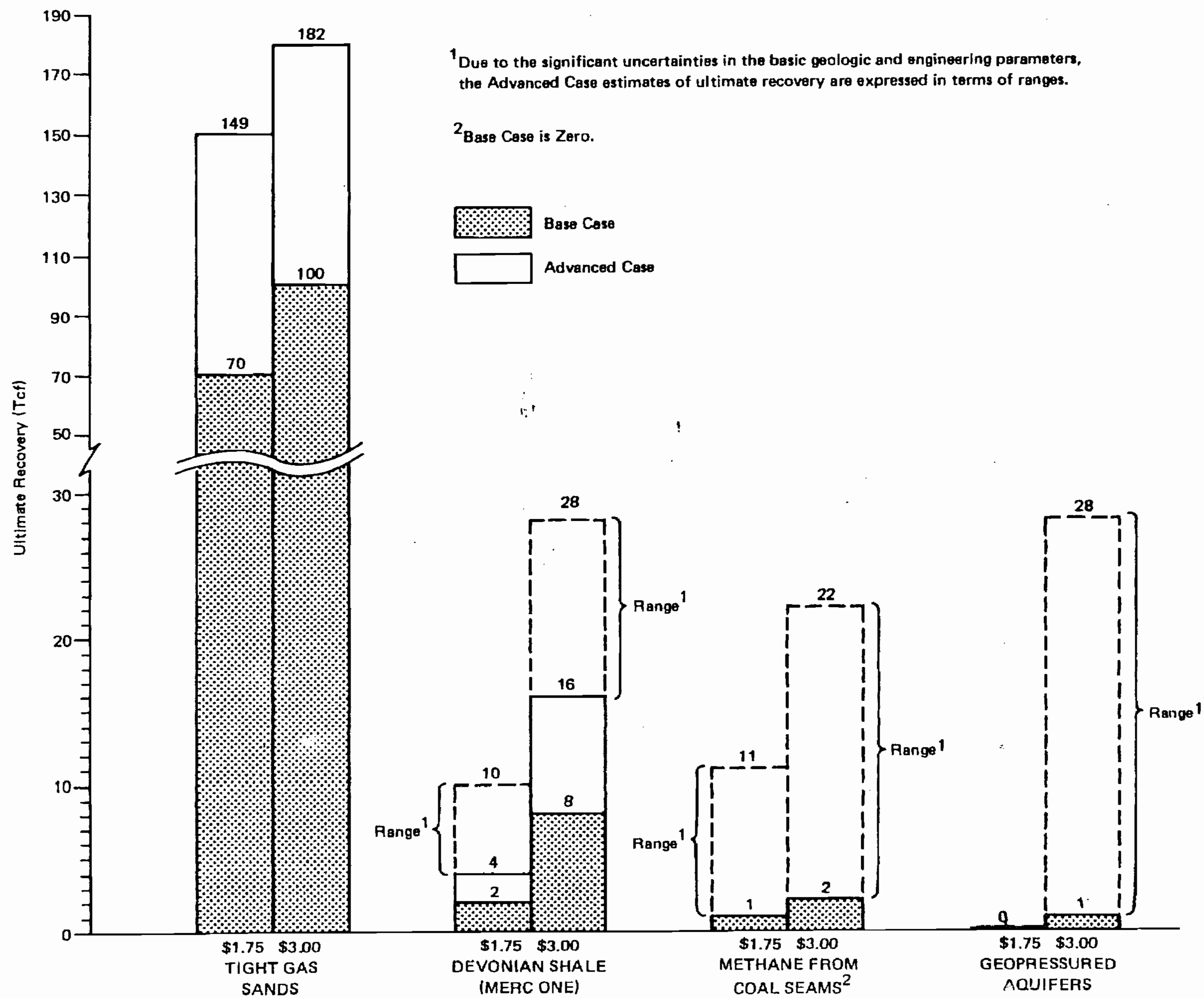
DRAFT

EXHIBIT 6
Incremental Annual Production Levels for DOE EGR R&D Program



DRAFT

EXHIBIT 7
Ultimate Recovery by Unconventional Resource Area
for DOE EGR R&D Program



- The methodology employed to develop the proposed program depends on the various estimates of major engineering, geologic, and economic variables which characterize specific unconventional resource areas and individual projects. Such estimates, while consistently derived, are subject to judgment and change as more is learned about the technical, economic, and institutional aspects of EGR. While widely divergent opinions and estimates concerning these major variables abound, the strategic analysis serving as the foundation for the recommended program took into consideration and utilized only those data which were fully supported by empirical evidence, historical precedent, and/or sound geologic-engineering theory. The recommended program contains a set of activities ("expanding the knowledge base") which focus on a detailed and continuous review, reevaluation, and additional investigation of the comprehensive analysis from which the recommended program was derived. As significant new insights are obtained, these will be incorporated into the EGR program strategy in the course of the anticipated regular reviews.

- The recommended program stresses a balance between near-term production goals and the need to more carefully assess the total economic potential of the speculative portions of the unconventional resources.

- The individual projects delineated in Exhibit 5 represent broad classes of focused R&D activities. They are not, however, so finely defined as to be field or reservoir specific. The final definition of these projects will be the major focus of subsequent implementation planning.

- Major environmental and socioeconomic factors bearing on the rate of commercialization were explicitly considered in program development. These factors were incorporated into a set of aggregate indices which described their potential impacts on the development and commercialization of individual projects. In-depth assessment of the environmental and

DRAFT

socioeconomic impacts, realistic estimates of the cost to mitigate the more significant factors, and the development of the overall strategy for environmental and socioeconomic quality assurance are major elements of the subsequent implementation plan phase.

- Since the individual programs in the recommended 5-year program require very large volumes of start-up funding, it is impractical to assume that the relatively small amount of discretionary funds available in the FY 79 EGR budget could provide anything more than a modest startup of the higher priority projects. In view of the time-phasing problem, the period from FY 80 to FY 84 is the proper context for the recommended 5-year DOE EGR program.

- The recommended 5-year program and budget were developed on an unconstrained basis and thus will have to be adjusted to conform to real budget limitations.

As depicted in Exhibit 8, the recommended 5-year program contains R&D projects in each of the four major unconventional resources. DOE funding requirements and percentages are as follows:

- Tight Gas Sands - $216.7 million (36 percent of the total program)

- Devonian Shale - $120.4 million (20 percent of the total program

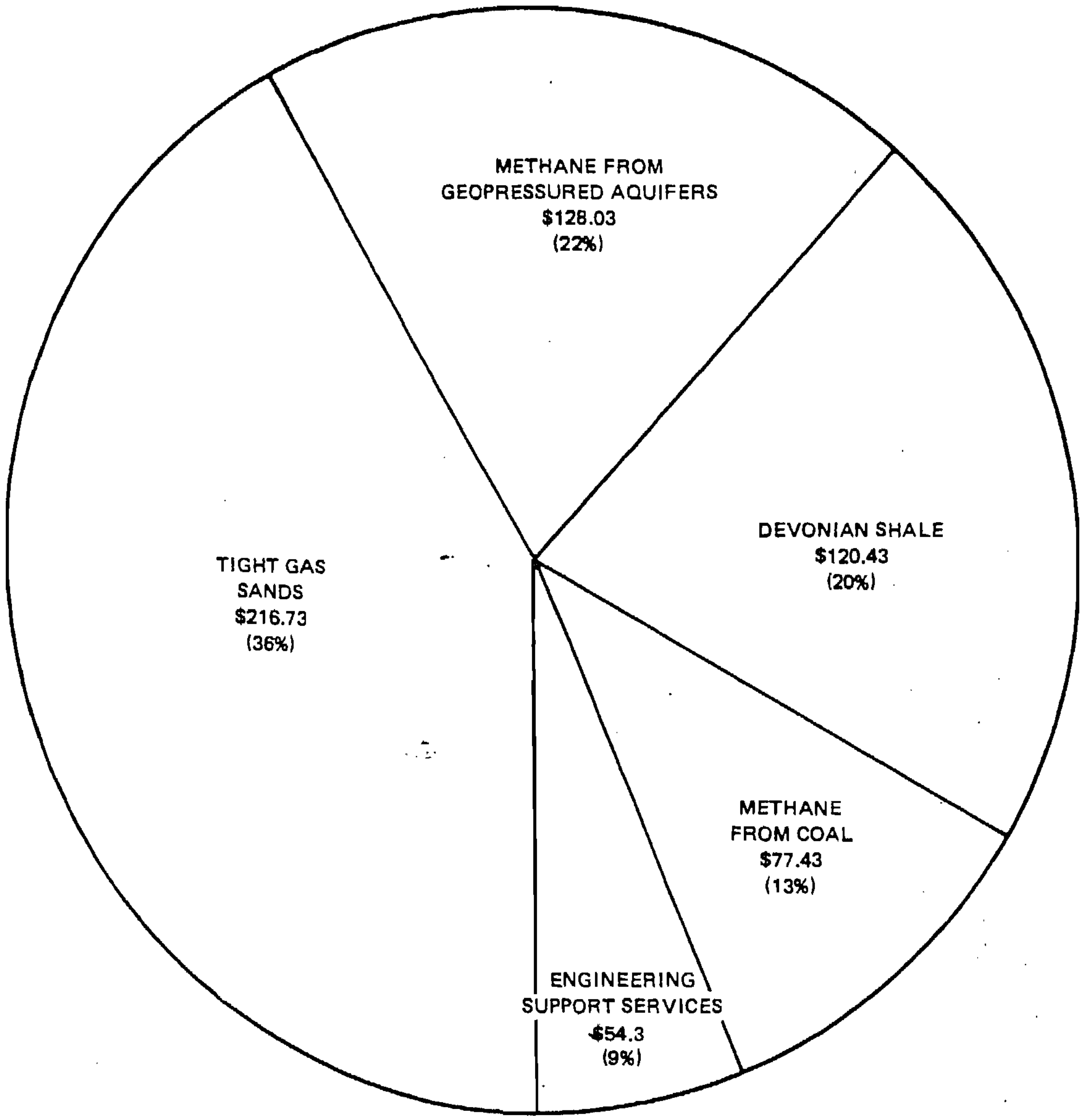
- Methane from Coal Seams - $77.4 million (13 percent of the total program)

- Geopressured Aquifers - $128.0 million (22 percent of the total program).

The remaining $54.3 million (9 percent of the total program) consists of the environmental and program support activities.

DRAFT

EXHIBIT 8
Total 5-year DOE Budget Required to Implement the Comprehensive EGR Program[1]
(Dollars in Millions)



[1]The total budget requirement to fully implement the recommended EGR program is $596.9 million (See Exhibit 5). Approximately $108.5 million of this total represents Group II project resource characterization activities which extend beyond the initial 5 years of the program.

DRAFT

(4) <u>Profile Analysis - Recommended Versus Current Program</u>

The recommended program represents a significant increase in annual DOE funding requirements ($119.3 million on the average versus $46.6 million for the current program in FY 78). The comparison of Exhibits 8 and 9 illustrates that associated with the recommended program are significant increases in the funding requirements of all four unconventional resource areas and the environmental and support activities. The annualized costs for the tight gas sands represent an eight-fold increase above the current level. For the other three unconventional resources, the annualized funding requirements associated with the recommended program range from 35 percent (Geopressured Aquifers) to 100 percent (Devionian Shales) above FY 79 levels.

In terms of relative funding levels, the recommended program represents a significant shift in emphasis toward the tight gas sands, which comprise 36 percent of total funding requirements, as opposed to the 11-percent figure under the FY 78 budget. Devonian Shales, while significantly increased under the recommended program in terms of annual funding levels, represent approximately 20 percent of the total program, as opposed to 26 percent under the FY 78 budget.

The relative shift in emphasis reflects the importance attached by key DOE managers to the significant near-term production potential associated with the tight gas sands. As indicated in Exhibit 5, the incremental ultimate recovery for the tight gas sands, which could be unlocked by a combination of high gas prices ($3.00 per Mcf) and federally sponsored R&D, is significantly greater than the economic recovery potential for Devonian Shales.

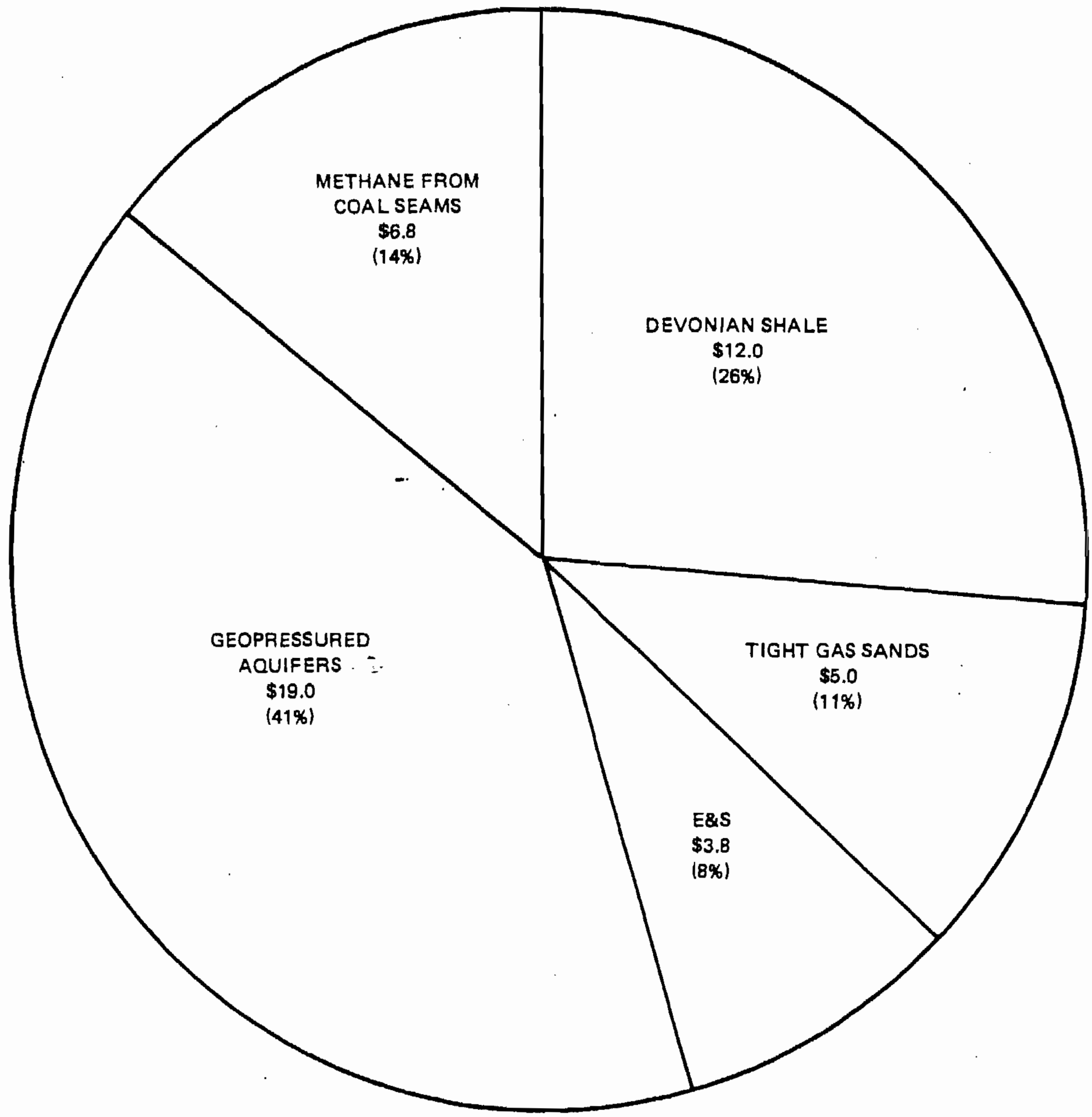
5. OVERVIEW OF METHODOLOGY

The principal steps followed in the development of this EGR program strategy are depicted in Exhibit 10. These included:

- Resource definition
- Economic evaluation of the resource
- Strategy and candidate projects development
- Establishment of project priorities
- Final program selection.

DRAFT

EXHIBIT 9
FY 78 DOE Funding for the Current
EGR Program
(Dollars in Millions)



DRAFT

(1) Resource Definition

The objective of the resource definition section was threefold:

- Assess the potential of conventional sources of natural gas and thus define the national need for EGR

- Classify and assess the potential (gas-in-place) of the unconventional resource base to which improved EGR technology is applicable

- Gather necessary engineering and geologic data to assess the recoverable gas potential of the applicable unconventional resource base.

The initial step entailed the identification of the economically recoverable gas from discovered conventional and unconventional resources. Estimates of Base Case production were subsequently derived for the resources. The next principal thrust focused on classifying the unconventional resource base into possible/probable areas (Group I) and speculative areas (Group II). Also, an assessment of the potential (gas-in-place) of each area was made. These two areas served as the general gas producing targets for the Advanced Technology Case. The last step was to collect sufficient engineering and geologic data necessary to make reasonable estimates of the recoverable gas potential for both probable/possible and speculative areas of the unconventional resource base.

(2) Economic Evaluation of Resource

The primary objective of this phase of the strategic analysis was to assess the supply potential from the unconventional resources at various natural gas prices, and under different assumptions concerning the state of development of EGR technology. There were four steps in achieving this objective.

- Develop analytical models

- Define Base Case and Advanced Case Technology

DRAFT

- Collect necessary economic, financial, and cost data necessary for the analytical models

- Exercise the analytical models to determine supply potentials at three natural gas prices: $1.75, $3.00, and $4.50 per Mcf.

The first step consisted of formulating three analytical models:

- Reservoir simulation model
- Project economics model
- Extrapolation/timing model.

Next, two technology cases were defined:

- Base Case: assumes expected technological advancements by only industry-sponsored R&D

- Advanced Case: assumes revolutionary technological advancement by Federal-industry-sponsored R&D.

The third step involved a detailed natural gas industry survey to obtain the required economic, financial, and cost data for input into the analytical models. The final step consisted of exercising the analytical models to estimate ultimate recovery and annual production rates at $1.75, $3.00, and $4.50 per Mcf.

(3) Strategy and Candidate Project Development

The objective of the strategy formulation and project development section was to specifically identify and characterize a set of feasible EGR projects which hold high possibility for realizing the potential of the unconventional gas resources. The methodology to accomplish this objective was fourfold:

- Identify major constraints to development

- Formulate strategies to overcome the constraints

- Identify high-potential targets and determine a set of high-potential projects

- Completely characterize projects in terms of their primary attributes.

DRAFT

The initial step consisted of the identification and prioritization of the major constraints to the full scale exploitation and commercialization of the unconventional resources. Extensive feedback from the private sector was used to clearly delineate and assess the relevant technical and nontechnical (economic, environmental, and institutional) constraints. Next, a set of four primary strategies or RD&D activities were formulated to overcome or mitigate the major identified constraints. Then, the high-potential targets of the probable/possible areas of the unconventional resources were identified. Strategies were applied to the high-potential areas to determine the set of high-potential EGR projects. The final step was to completely characterize the projects on the basis of a set of performance parameters which comprehensively indicated the principal benefits, costs, and impacts associated with their full scale commercialization.

(4) Establishment of Project Priorities

The purpose of the prioritization process was to provide EGR program managers with specific insights concerning the potential impacts of constrained budget levels on the timing, composition, and amount of benefits associated with the recommended EGR program.

In accomplishing this objective, two steps were involved:

- An analytical survey to establish Group I priorities was developed and implemented
- In-depth interviews were conducted to establish priorities among Group II projects and also between Group I and Group II projects as a whole.

The analytical survey was conducted with 11 key DOE Energy Technology managers responsible for planning and implementing the EGR program. This survey process served as the basis for establishing priorities among the Group I projects.

ts

The in-depth personal interviews established the tradeoffs which the 11 key managers would make among the 21 candidate projects at various levels. The results of the interviews were used to establish priorities among Group II projects and between Group I and Group II projects as a whole.

(5) Final Program Selection

The objective of this phase of the strategic analysis was to refine the 21 high-potential Group I and Group II projects into a recommended 5-year DOE EGR R&D program. The three principal steps in this refinement process included the following:

- Conducted tradeoff analysis to assess the ability of the set of high-potential R&D projects, higher gas prices, and a combination of R&D and higher gas prices to significantly increase gas production from unconventional sources

- Performed a profile analysis (by comparing the tentative recommended program with the current DOE EGR program) to identify and review indicated new program thrusts

- Incorporated key qualitative and programmatic factors which were not explicitly included in the analysis and prioritization of the set of 21 high-potential R&D projects.

First, a detailed tradeoff analysis between the three levels of prices ($1.75, $3.00, and $4.50/Mcf) and the two technology cases (Base and Advanced) was performed. This allowed the formation of insights into the effects of economic and technological advances on natural gas production from unconventional resources. Next, a detailed comparison of the recommended, unconstrained and current EGR programs was performed to clearly delineate significant changes in program philosophy and direction and to make certain that such changes had been carefully and explicitly analyzed. The recommended, unconstrained program is that displayed in Exhibit 5.

DRAFT

Finally, an evaluation and incorporation of key budget, qualitative, and programmatic factors into the recommended, unconstrained 5-year program will be required. This analysis is not complete at this time. It involves evaluating such factors as program diversification requirements, time and risk preference, regional market considerations historical and anticipated budget levels, program phasing requirements, knowledge base activities, and environmental, general support and technology transfer. Once these factors are fully taken into consideration, a final EGR program will be outlined.

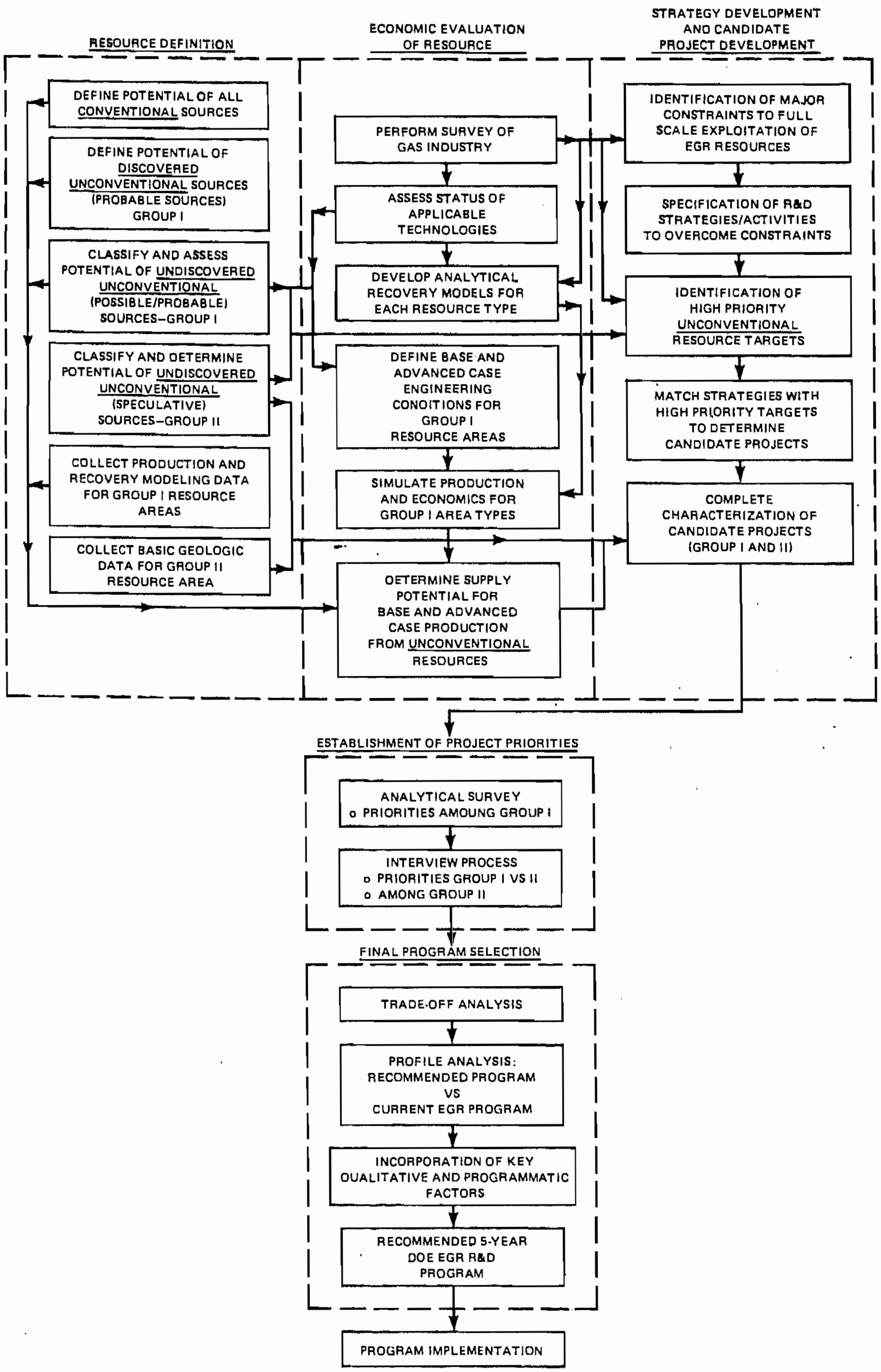
* * * *

The detailed analyses and results of each of the five steps of the methodology (Exhibit 10) are presented in the body of the report. The report is organized into five chapters—one chapter for each step in the overall methodology of the strategic analysis. As displayed in Exhibit 10 and discussed above, these five steps (and thus five chapters), are as follows:

- I - Resource Definition
- II - Economic Evaluation of the Resource
- III - Strategy Development and Candidate Projects Development
- IV - Establishment of Project Priorities
- V - Final Program Selection.

DRAFT

EXHIBIT 10
Methodology Employed for the Formulation of the Enhanced Gas Recovery Strategic Plan



DRAFT

I. RESOURCE DEFINITION

As depicted in Exhibit 10 of the Executive Summary, resource definition was the first step of the strategic analysis supporting the recommended Department of Energy (DOE) Enhanced Gas Recovery (EGR) R&D program. The objectives of the resource definition step were threefold: (1) assess the potential of conventional sources of natural gas recovery and thus define the national need for enhanced gas recovery, (2) classify and assess the potential (gas-in-place) of the unconventional resource base to which the EGR technology is applicable, and (3) gather necessary engineering and geologic data to assess the recovery potential of the applicable unconventional resource base.

1. POTENTIAL OF CONVENTIONAL SOURCES AND THE NEED FOR EGR

The conventional natural gas supply for the next few decades will be produced from the following three primary sources[1]:

- Proved reserves
- Growth in proved reserves through developmental drilling
- New additions from exploration.

Proved reserves in the lower 48 states are estimated at 184 Tcf, and Alaskan proved reserves are estimated at 31.9 Tcf. Developmental drilling, which has accounted for 80 percent of the additions to reserves in the past, is estimated ultimately to contribute 98 Tcf. New supply from exploration is estimated to add 1.5 Tcf per year, and ultimately contribute 5.8 Tcf through developmental drilling applications.

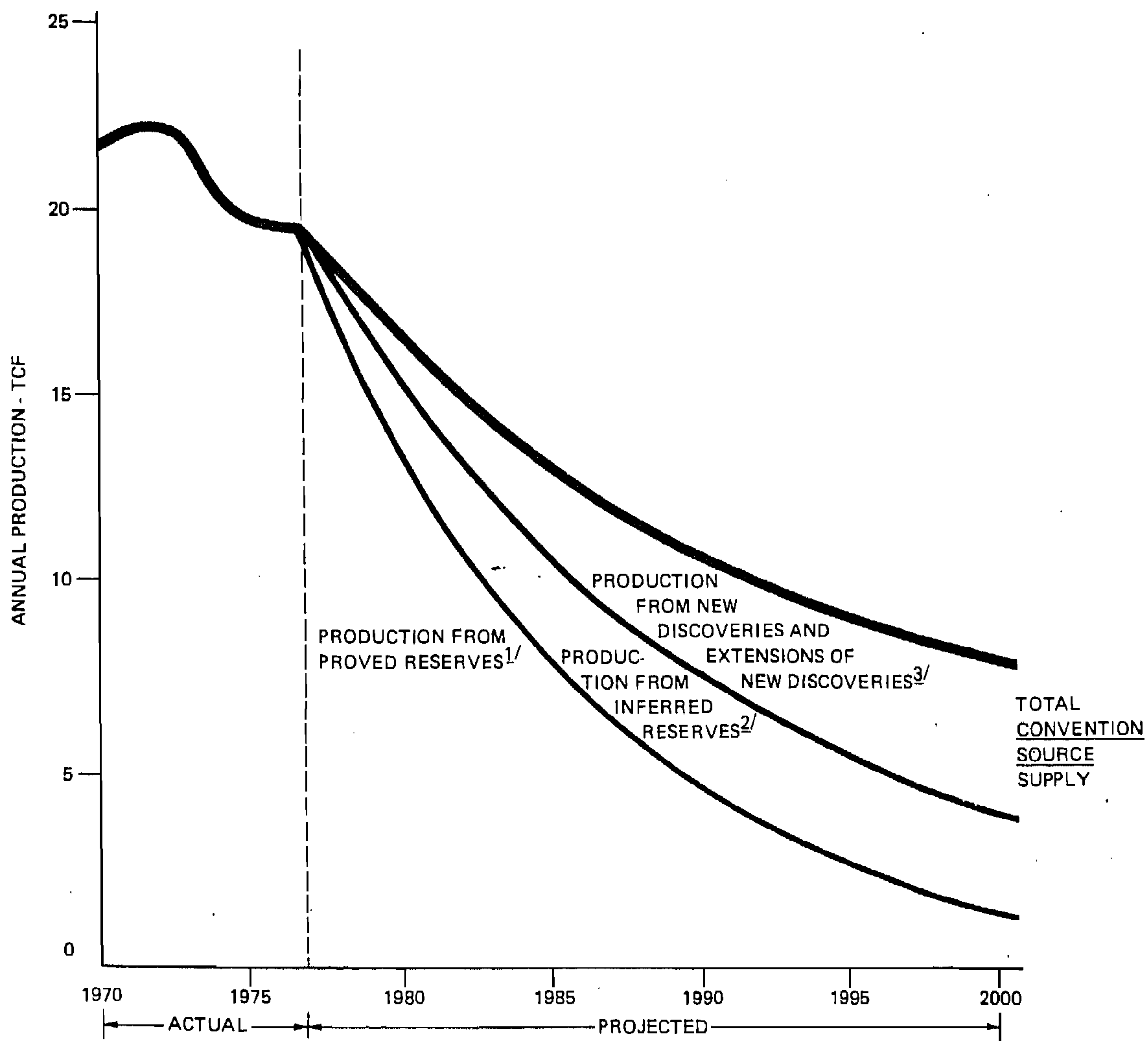
The projections that result from the combination of these three sources indicate a continuing decline in gas supply throughout the rest of this century (see Exhibit I-1).

---

1 See Appendix A for a detailed discussion of the conventional natural gas reserves.

DRAFT

EXHIBIT I-1
Projected Production From Conventional Gas Reserves
(at Gas Price of $1.75/Mcf)



1/ RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS AND NATURAL GAS IN THE UNITED STATES AND CANADA AS OF DECEMBER 31, 1976, BY AGA/API/CPA.

2/ BASED ON A RECENT LEWIN AND ASSOCIATES, INC., STUDY, ANALYSIS OF THE TIMING AND TOTAL OF INFERRED RESERVES OF NATURAL GAS IN THE CONTIGUOUS UNITED STATES, BY J. BRASHEAR AND F. MORRA.

3/ BASED ON ONSHORE (LOWER 48) DISCOVERIES OF 1.0 TCF/YEAR AND OFFSHORE (LOWER 48) DISCOVERIES OF 0.5 TCF/YEAR, GROWING TO 3.9 AND 1.9 TCF RESPECTIVELY THROUGH DEVELOPMENTAL DRILLING.

DRAFT

The national need for an expanded R&D program in EGR is underscored by the combination of this projected decline in conventional gas supply and the growing demand for natural gas. This demand has been increasing at a significant rate since the early 1970s.

2. CLASSIFICATION AND ASSESSMENT OF THE POTENTIAL (GAS-IN-PLACE) OF THE DISCOVERED AND UNDISCOVERED, UNCONVENTIONAL RESOURCES

Discovered (probable), unconventional resources are presently contributing 1 Tcf per year to the domestic gas supply (production from wells in the most favorable areas of the tight gas sands and Devonian shales). It has been estimated that this level could increase to over 2 Tcf annually by 1990. Undiscovered, unconventional resources are traditionally classified into three groupings[1]: (1) probable, (2) possible, and (3) speculative areas. The probable areas are those in which new supplies of gas are most assured of growing. The classification pertains to the growth or expansion of existing producing fields and includes new pools in productive discovered reservoirs and shallow or deeper new pool discoveries within existing formations. In addition, this classification also represents the resource areas where significant data are abundant and readily accessible.

The possible resource areas consist of new field discoveries in geological formations that have proved productive over the years. These new field discoveries are treated as distinct from existing producing formations. The data that exist in this classification were less specific and abundant than the data for the probable classification. The estimated gas-in-place associated with the probable and possible areas is 864 Tcf.[2]

The speculative resource areas consist of previously unproductive formations or provinces. New supplies from these areas would be directly attributable to new and

---

1 Potential Gas Committee, Potential Supply of Natural Gas in the United States, December 31, 1976, p. 1.

2 This estimate was derived from the Lewin Associates report, Enhanced Recovery of Unconventional Gas-Volume II, February 1978, and from the Federal Power Commission report, Subtask Force IV-Gas in Tight Formations, March 1977.

advanced exploration and production techniques. The speculative resource areas are also characterized by a lack of the engineering and geologic data necessary to assess reliably the recovery potential of the resources. Estimates of gas-in-place are widely divergent and range from 1,000 to 6,000 Tcf.

The probable area of the discovered and the probable and possible areas of the undiscovered, unconventional resources were identified as the principal targets for the development and application of improved EGR technology. These resource areas were called Group I resources for the purpose of the strategic analysis. The speculative areas of the undiscovered unconventional resources, called Group II resources for purposes of the strategic analysis, were identified as the primary target for in-depth resource characterization. Exhibit I-2 highlights the salient characteristics of Groups I and II resource areas.

3. COLLECTION OF ENGINEERING AND GEOLOGIC DATA

(1) Group I Resources

An extensive data collection and analysis effort was conducted to obtain the necessary geologic and engineering data to assess reliably the recovery potential of the possible and probable areas and to serve subsequently as the primary basis for selecting high-potential targets for the application of improved EGR technology. The major kinds of data collected and analyzed for each of the four unconventional resource areas are summarized below.[1]

- Tight gas sands and Devonian shales
  - Location/identification of possible and probable areas with production potential by basin, sub-basin or reservoir
  - Geology/lithology, including formation name, rock type, trap type, general stratigraphy, and tectonics

[1] Appendix B contains a more detailed description of the data collected and the principal sources utilized in this effort.

DRAFT

DRAFT

EXHIBIT I-2
Salient Characteristics of Group I and Group II
Unconventional Resource Areas

	Resource Classification	Data Availability	Resource Characterization Purpose	Technology Development Purpose	Ultimate R&D Goals
Group I	Includes areas of probable or possible discovered and undiscovered resources[1]	Specific geologic and well data available[2]	Detailed resource characterization to clearly define in situ parameters which control the design of a field test	Field tests directed at solving the drilling, completion, and production problems associated with in situ parameters	. Verify production economics . Prove technology . Determine timing and success rates . Transfer results industrywide
Group II	Includes areas of speculative undiscovered resource[1]	General geologic and minimal or no well data available	Broad based resource characterization including basic geologic studies and drilling to define more favorable speculative areas	Develop and test new exploration techniques to unconventional resources but possibly applicable to conventional resources as well	. Delineate new and most favorable areas for inclusion in Group I process

[1]As defined by accepted resource classification systems used by AGI, USGS, and Potential Gas Committee.

[2]Availability of these data allows generation of engineering and economic estimates of the potential gas recovery.

- Reservoir parameters, including depth, thickness, number of zones, productive acres, porosity, permeability, and initial reservoir pressure

- Water saturation

- Gas characteristics, including gas type and reservoir gas gravity

- Development history (if available) of the area and surrounding areas

- Gas volumes, including initial wet gas in place and cumulative wet gas production

. Methane from coal seams[1]

  - Estimates of the unminable coal from which methane can potentially be recovered encompass coal which is too thin or too deep to be mined and is subbituminous or higher in rank. Therefore, these estimates included thin coals averaging 15 inches but not exceeding 24 inches, and coals occurring at depths between 3,000 to 6,000 feet.

  - Estimates for methane recovery from minable coal were based on the rate of present and projected mining as opposed to actual coal deposits that would be drained. These estimates were therefore derived from collected data on the number of existing mines and the projected mine openings required to meet projected coal demand, on emission rates as determined from existing bituminous coal mines, and on regional variations of the first two factors.

---

1 The vastness of the coal resources in the United States precluded the type of basin/reservoir analysis that was employed for the tight gas sands and the Devonian shales.

DRAFT

- Geopressured aquifers[1]

  - Identification of the major geothermal/geopressured fairways in the onshore Gulf Coast area (six prospective areas in Texas and eight in Louisiana)

  - Collection for each fairway of relevant data on temperature, pressure, dissolved solids, permeability, net pay, and areal extent.

(2) Group II Resources

The Group II resources are characterized by lack of sufficient engineering and geologic data to assess reliably their potential. In most cases, little or no drilling data exist, and only general geologic information is available. Relying extensively on published research and a minimum of new investigation, the EGR Working Group[2] developed basic data on three broad characteristics of the speculative areas of the four unconventional resource areas as follows:

- Size of the speculative areas in terms of square miles

- Estimated thickness of productive zones/formations and gas concentration per unit volume

- Volumes of gas-in-place and technically recoverable gas.

---

1 The data collection and analysis approach was essentially the same as the approach pursued in the methane from coal resource area.

2 The EGR Working Group consisted of representatives from DOE Headquarters; Federal Research Labs, including MERC, BERC, LLL, and Sandia; and contractor organizations, including Booz, Allen & Hamilton Inc., and Lewin and Associates. A complete list of the working group representatives is available in Appendix C.

DRAFT

*   *   *   *

As depicted in Exhibit 10 of the executive summary, the basic geologic and engineering data were subsequently combined with economic and cost information to develop estimates of supply potential for the four unconventional resource areas. Chapter II presents the details of this economic evaluation of the unconventional resources.

II. ECONOMIC EVALUATION OF RESOURCE

1. INTRODUCTION

The primary objective of this phase of the strategic analysis was to assess the supply potential from the unconventional resources at various natural gas prices and under different assumptions concerning the state of development of EGR technology. There were four principal steps taken to achieve this objective as follows:

- Development of analytical recovery models
- Definition of a Base Case and Advanced (technology) Case
- Collection of necessary economic, financial, and cost data to assess potential economic recovery
- Exercising of the analytical recovery models using as inputs the data from the previous two steps and projecting production levels and ultimate recovery (for each unconventional resource) in the Base and Advanced Cases at natural gas prices of $1.75, $3.00, and $4.50 per Mcf.

2. DATA SOURCES

An extensive survey[1] of the natural gas industry provided the major data inputs used to assess the current status of private sector EGR R&D and structure the project economics model.[2] The survey encompassed 75 firms in the production, transmission, and distribution sectors of the natural gas industry and 13 major coal mining companies.

---

1 Refer to Appendix D for a comprehensive description of the industry survey.

2 Booz, Allen & Hamilton Inc., Empirical Study of the Natural Gas Industry, August 1977.

DRAFT

The survey focused on corporate executives responsible for the initiation, development, funding, and management of EGR R&D in their respective firms. Additional inputs were obtained by a significant expansion of the current DOE/Energy Technology (ET) interface with the natural gas and coal mining industries.

3. DEVELOPMENT OF ANALYTICAL RECOVERY MODELS

The assessment of the economic supply potential of the tight gas sands and Devonian shales was conducted through the exercise of three analytical models developed during the course of the strategic analysis.[1] As depicted in Exhibit II-1, Base Case and Advanced Case projections of production rates and ultimate recovery at various gas prices were developed from the reservoir simulation, project economics, and extrapolation/timing models. Exhibit II-2 presents the salient characteristics of these models as they were applied to the analysis of the tight gas sands and Devonian shales.

The models developed to assess the economic potential of the geopressured aquifers and methane recovery from coal seams were significantly less detailed than the analytical recovery models for the other two unconventional resource areas. The economic recovery model for minable and unminable coal seams was based on two important assumptions: (1) thickness of the coal seam as the controlling variable and (2) favorable levels for all other relevant geological parameters. Thus, the ultimate feasibility of significant economic recovery depended on finding coal deposits of sufficient thickness. Exhibit II-3 delineates the other major assumptions employed in the methane recovery model.

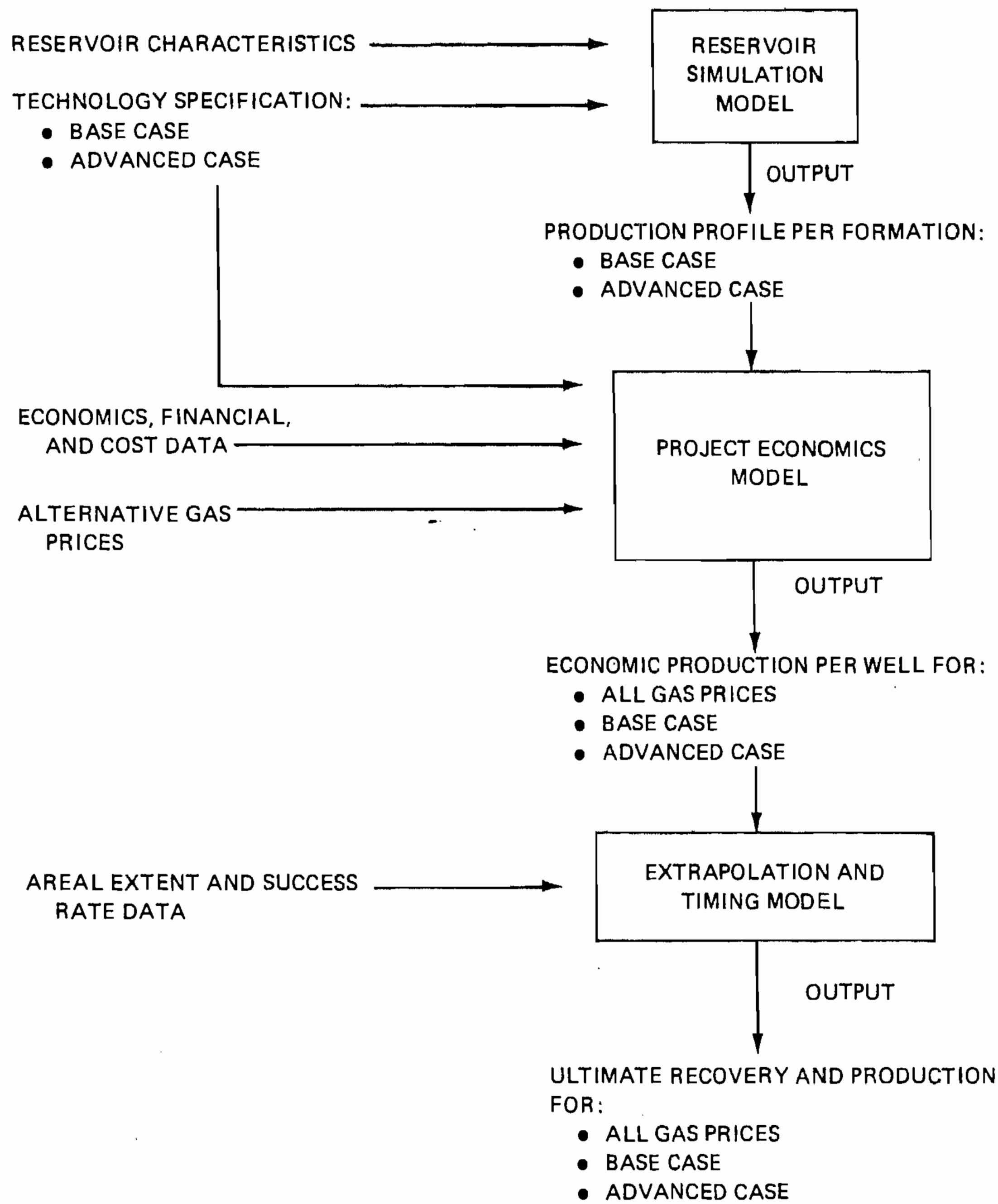
In the case of the geopressured aquifers, the economic recovery potential was assessed on the basis of a simple investment payback model. The three principal steps in this analysis included:

---

1 Refer to Appendix E for detailed descriptions of the analytical models.

DRAFT

EXHIBIT II-1
Analytical Framework Used to Assess the Economic Recovery Potential of the Tight Gas Sands and Devonian Shales



DRAFT

EXHIBIT II-2
Salient Characteristics of the Analytical Models Used to Assess the Economic Recovery Potential of the Tight Gas Sands and Devonian Shale

Model/Resource Area		Assumptions	Inputs	Model Activities	Limitations/Comments
Reservoir Simulation Model	Tight Gas Sands	• Reservoir is homogeneous and isotropic or unhomogenous • Assumes linear gas flow • Assumes radial flow pattern from a fractured reservoir • Accounts for effect of non-Darcy flow • Accounts for decrease in pressure due to production	• Reservoir/geologic data for 622 units • Engineering specifications for Base and Advanced Cases	Simulates flow of gas in a porous media	Production rates were based on data from each analytic unit/reservoir
	Devonian Shale		• Reservoir/geologic data for 35 units • Engineering specifications for Base and Advanced Cases		Production curve based only on productive area in Kentucky and West Virginia. Production curve was extrapolated to other analytic units
Project Economics Model	Tight Gas Sands	• Uses discounted cash flow (NPV) as capital investment criteria • All costs expressed as constant 1977 \$ • Regional cost factors • 20 percent discount rate for Base Case in NPV calculation • 10 percent discount rate for Advanced Case in NPV calculation	Cost Inputs • Gas price \$1.75, \$3.00, \$4.50 • Investment costs: exploration, drilling, completion, dryhole costs, stimulation, basic lease and well equipment, compressor costs • Basic operating and maintenance costs • Royalties and taxes • Other factors: depreciation rate, investment timing, inflation indices	Estimates that portion of the technically recoverable gas that could be commercially produced at three prices: \$1.75, \$3.00, \$4.50	Model employs discount rates representative of the industry "on average" and thus gives no consideration to individual company differences, which are significant. Applying average discount rates to assess the economic potential of portions of the resource areas already under lease to individual firms can lead to an under- or overstatement of economic recovery potential depending on the specific discount rates employed by these individual companies
	Devonian Shale				
Extrapolation and Timing Model	Tight Gas Sands	• Assumes total possible and probable acreage x drilling success rate will be developed • Assumes 30 years of production • Assumes possible acreage begins to develop when probable acreage has reached maximum production • Advanced case shows a three-year drilling lag due to time required for technology breakthroughs • Assumes that different portions of a reservoir/basin will come on at different prices	Analytic Unit Inputs • Acreage: possible/probable • Acreage assignments by price • Success rate • Production estimate per well at three prices: \$1.75, \$3.00, \$4.50	• Determines the amount of acreage that is profitable • Converts the acreage into total number of wells to be drilled • Sequences drilling and production of these wells into the future under either the Base or Advanced Case • Develops ultimate production and annual production rates for Base and Advanced Case	
	Devonian Shale				

EXHIBIT II-3
Major Assumptions Employed in the Assessment
of Economic Recovery Potential of Methane From Coal Seams

Parameter/Element	Assumption
• Controlling Factors In Economic Recovery	• Thickness of coal seam • Ability to find coal deposits of sufficient thickness
• Deviated Well Costs and Drilling Strategy	• Total costs of $600,000 • Two wells drilled to 4,000 feet, then 1,000 feet into coal bed • Deviated wells are used to connect the natural fracture system
• Drainage Area	• 72 acres
• Methane Content	• 480 cubic feet per ton or 0.019 Mcf per cubic foot in bituminous and higher grades
• Recovery Efficiency	• 80 percent
• Gas Diffusion Constant	• 5×10^{-8} cm^2/sec
• Natural Fractures	• One foot centers (both butt and face cleats)
• Recovery Rates	• For minable seams, rate was calculated relative to pace of current mining and the opening of new mines
• Economic Evaluation Criteria	• Maximum 10-year payback

DRAFT

- Calculating the minimum methane content required per barrel of produced water to pay operating and water disposal costs[1]

- Determining the required production rate/methane content combination required to pay back the initial investment under high- and low-risk investment criteria

- Applying these production rate/methane content threshold criteria to the most clearly defined fairways in onshore Texas (six fairways) and Louisiana (eight fairways).

Other major assumptions in the analysis included an 85-percent recovery efficiency of methane dissolved in the brine, 12.5 percent royalty payments, and 8 percent severance/other taxes.

4. DEFINITION OF BASE AND ADVANCED (TECHNOLOGY) CASES

Two scenarios of EGR technology R&D (Base and Advanced Cases) were developed in order to assess the ability of Federally sponsored R&D to cost-effectively unlock the potential of the Group I unconventional resources. The scenarios were important instruments which were subsequently employed to address the trade-off between the use of market forces (prices and taxes) and improved technology to augment domestic supplies of natural gas.

The Base Case reflects the current state-of-the-art plus anticipated advances over the next 5 years in EGR technology. The Advanced Case represents evolutionary technological advances that hold reasonable promise of being achieved through Federally sponsored, accelerated R&D. The initial and principal step in the specification of these two cases was a comprehensive assessment of the current status and anticipated private sector R&D in EGR. Extensive interaction with industry and the comprehensive

---

1 The analysis considered the production of methane as the primary purpose but did not consider either the cost or the output value of thermal or hydraulic energy recovery. This was done for two reasons. First, the examination of thermal/hydraulic energy recovery was specifically excluded from the scope of this effort. Second, much of the area defined as being geopressured had temperatures between 200°-300°F and thus had relatively low potential for thermal energy output. (The theoretical thermal output at 200°F is about one-fifth of the thermal output at 325°F.)

DRAFT

industry survey provided the primary basis for the assessment. Exhibit II-4 delineates the more important findings for each of the four unconventional resources. This data base was then used to specify the primary geologic, engineering, and economic parameters defining the Base and Advanced Cases (Exhibits II-5 through II-7).

5. COLLECTION OF ECONOMIC, FINANCIAL, AND COST DATA

Traditional financial analysis methods were used to estimate the portion of technically recoverable gas that could be commercially produced at three prices. As previously discussed, the tight gas sands and Devonian shale were analyzed using a discounted cash flow (NPV) model. The geopressured aquifers and methane recovery from coal seams were assessed via an investment payback model. The core of these project economic models was the estimation of the cash flow streams generated by the assumed levels of capital investment. This positive cash flow stream was established by multiplying the production for a year (from the production model of Exhibit II-2) by the appropriate gas price and subtracting the relevant investment costs in the initial year and operating costs, royalties, and allocated costs in each year to the end of the well's productive life. The individual cash flows were thus derived as a function of the following set of parameters:

- Production as governed by geology and technology
- Natural gas prices
- Investment costs
- Operations and maintenance costs
- Royalties, severance taxes, Federal and state income taxes
- Tangible and intangible costs
- Depreciation
- General and administrative costs.

The important characteristics and assumptions concerning these data are displayed in Exhibit II-8. The primary data itself were collected extensively from four major sources: (1) historical records of individual companies,

DRAFT

EXHIBIT II-4
Existing Recovery Technology

Unconventional Resource Area	Enhanced Gas Recovery Technology	Major Characteristics	Historical Effectiveness/Results
Tight Gas Sands	Massive Hydraulic Fracturing	• Creates a vertical fracture which intersects net pay for considerable distances (sometimes as high as 1500-2500 feet). • Fracture is created by high pressure injection of fluids through well perforations. • Injection fluid also carries proppant (solid particles) into the fracture to keep it open. • Fluid volumes range from 100,000 to 500,000 gallons and sand volumes range from 200,000 to 1,000,000 lbs. • Fracturing of multiple intervals in same well is possible.	• This technology has been effective in near tight formations and in tight blanket sands. Fracture lengths have exceeded 1500 feet on both sides of the wellbore. • Much remains to be learned in order to apply MHF to lenticular sands.
Devonian Shales	"Shooting"/Conventional Explosives	• Creates a rubblized area around the wellbore and overcomes wellbore damage.	• Typically improves initial open flows 4 to 6 fold. • Does <u>not</u> create fractures which extend a significant distance from the wellbore.
	Small Hydraulic Fracturing	• Creates a vertical fracture which intersects net pay for short distances from the wellbore (typically 100-200 feet). • Fluid volumes are typically 40,000 gallons and sand volumes are typically 80,000 lbs. • Fracture typically increases early recovery rate by providing high permeability path to wellbore. • Fracture places the wellbore in contact with fracture porosity not contacted by shooting, thus increasing ultimate recovery.	• Recovery over shooting/conventional explosives typically improves 40 to 55%. • Large improvements are more common in wells with shorter production lives.
Methane From Coal	Vertical Boreholes Drilled From Surface	• Boreholes drilled into coalbed from surface with small diameter pipe (9 in. or less) • Coal seam is hydraulically fractured with fluids and sand.	• Rate of methane production depends on extent of hydraulic fracture and methane content of coal. • Production from Appalachian coal seams rarely exceeds 100 Mcf per day per well.
	Deviated Holes Drilled From Surface	• Small diameter borehole is drilled from surface and deflected to parallel the coal seam. • Using this technique maximizes the intersection of the coal cleat systems.	• Results to date have been disappointing. • Recovery rates have been minimal and do not justify the excessive costs for deviated wells.
	Horizontal Boreholes From Shaft Bottoms	• A large shaft is drilled from the surface to the coal seam. • Several horizontal holes are drilled into the coal seam from the bottom of the shaft. Borehole size is typically 3 inches. • Gas is collected in a manifold and piped to the surface.	• Tests to date (Pittsburgh Coal Bed) indicate that 100 MMcf of gas can be recovered over a 4-year period from each horizontal borehole.
	Horizontal Boreholes in Active Mines	• Small diameter horizontal boreholes are drilled into the coal seam 500 to 1000 feet as the working face advances. • Drilling is typically performed 2 to 4 weeks ahead of mining. • Gas is collected in a manifold and transported by a pipeline to the surface.	• Production to date from horizontal boreholes in advance of mining indicates an average production of 100 Mcf/day for 30 days.
Methane From Geopressured Aquifers	Conventional Drilling and Completion Technology	• Drilling and completion into geopressured aquifers is accomplished with conventional equipment including drill rigs casing, and perforating.	• No commercial production has taken place.
	Water Separation and Reinjection Equipment	• Large scale equipment for water separation and reinjection has not been developed or tested.	

DRAFT

DRAFT

EXHIBIT II-5
Specifications for the Base and Advanced Cases in the Tight Gas Sands

Parameter	Base Case	Advanced Case
. Eligible Formations	Limited to those demonstrated to be geologically favorable	All
. Dry Hole Rate		
- Lenticular	30%	20%
- Blanket	20%	10%
Technology		
. Fracture Length (one way)		
- Shallow gas sands	200 feet	500 feet
- Near-tight gas sands	500 feet	500 feet
- Tight gas sands	1000 feet	1500 feet
. Fracture Conductivity	Decreases with depths using current proppants and methods	(With improved proppants and methods maintaining adequate conductivity)
. Field Development		
- Lenticular	320 acres/well (2 wells/section)	107 acres/well (6 wells/section
- Blanket	160 acres/well (4 wells/section)	160 acres/well (4 wells/section)
. New Pay Contacted		
- Lenticular gas sands		
-- 320 acres drainage	17%	
-- 107 acres drainage		80%
- Blanket	100%	100%
Economics		
. Cost of Delivered Fracture	120%	100%
. Risks - reflected in discount rate of	26%	16%
Development		
. Start Year for Drilling		
- Probable Acres	1978	1981 (RD&D effect begins)
- Possible Acres	1987	1987
. Development Pace		
- Probable Acres	17 years to completion	13 years to completion
- Possible Acres	17 years to completion	15 years to completion

FXHIBIT II-6
Specifications for the Base
and Advanced Cases in the Devonian Shale

Parameter	Base Case	Advanced Case
<u>Resource Characterization</u>		
. Eligible Areas	Probable Areas	Probable and Possible Areas
. Dry Hole Rates	20%	10%
<u>Technology</u>		
. Completions	Single	Dual where low producer underlain by other productive pay
. Stimulation	Proposed 1000-bbl fractures	Optimized fractures
. Recovery Efficiency per unit area	Current levels	Improved by 20% in higher producing areas
<u>Economics</u>		
. Risks - reflected in discount rates[1] of	21%	16%
<u>Development</u>		
. Start Year for Drilling		
- Probable Areas	1978	1981 (R&D effect begins)
- Possible Areas	1987	1987
. Development Place		
- Probable Areas	17 years to completion	13 years to completion
- Possible Areas	17 years to completion	15 years to completion

[1] Discount rates include a 6-percent inflation component.

DRAFT

DRAFT

EXHIBIT II-7
Major Characteristics of Advanced Case For Methane From Coal and Methane From Geopressured Aquifers[1]

Strategy/Item	Coal Seam	Geopressured Aquifers
. Eligible Formations	Limited to seams of adequate thickness, adequate methane content, and higher grade.	Clearly delineated fairways in Texas and other prospective areas in Louisiana
. Dry Hole Rate	0%	25%
Technology		
. Drilling Technique	Deviated wells . 4000' deep . 1000' horizontally	Conventional drilling . 17,000 feet deep
. Pay Contact	100% of coal seam	100-500 feet
. Field Development	72 acres/well	16-60 square miles/well
. Recovery Factor	Decreasing recovery efficiency factor	5% resource recovery 85% methane extraction recovery at surface
. Methane Content	480 cf/ton	15-45 cf/barrel
Economics		
. Risk approach	10 year payback after taxes	10 year payback before taxes
Development		
. Time Frame	Ultimate recovery over 30 years (annual production timing not developed)	Ultimate recovery over 10 years (annual production timing not developed)

[1] Since there is little or no economic production of methane from minable or unminable coal seams, engineering parameters were not assigned to a base case. Likewise, there is no base case for geopressured aquifers.

state and local agencies, and industry associations; (2) technical and economic literature; (3) comprehensive gas industry survey; and (4) prior studies.

Three natural gas prices were employed to assess the ability of the market mechanism to unlock the potential of the unconventional gas resources and to assess the trade-offs between higher gas prices and Federally sponsored R&D. The $1.75 per Mcf price represented a deregulated estimate of the current price, $1.43 per Mcf, while the $4.50 per Mcf price was used as an upper level reflecting the price at which synthetic gas becomes economically competitive. The $3.00 per Mcf price represented the approximate price at which gas was equivalent to imported fuel oil (accounting for the environmental cost advantages of gas over oil).

6. EXERCISING THE ANALYTICAL RECOVERY MODELS

Employing as inputs the geologic and engineering data developed in the Resource Definition step of the strategic analysis and the financial, economic, and cost data developed in this step, the analytical recovery models were exercised to estimate the annual production and ultimate recovery levels for each of the four unconventional resources. These estimates were developed for the three gas price levels and for the Base and Advanced (technology) cases.

Exhibit II-9 demonstrates that the ultimate recovery from the unconventional resources is approximately 70 Tcf (Base Case) at $1.75 per Mcf. Raising the price of natural gas increases ultimate recovery from about 70 to 110 Tcf and raises the 1990 production rate from slightly over 2 to 3.5 Tcf. The increased price has a direct and significant effect on gas production from the tight gas basins and the Devonian shale but is insufficient to stimulate production from geopressured aquifers and methane from coal seams.

At a price of $3.00 per Mcf, however, an intensive government-industry cooperative R&D program jointly instituted (Advanced Case) would increase ultimate recovery to 200-260 Tcf and raise annual production to over 8 Tcf by 1990. Thus, the greatest total production from unconventional resources would accrue from a combination of improved economic incentives and advanced technology. The higher gas price ($3.00 per Mcf) combined with advanced technology will enable gas producers to develop the less productive areas of the Devonian shales in the Appalachian Basin and

EXHIBIT II-8
Major Categories of the Economic, Financial, and Cost Data Used in Assessing the Economic Recovery Potential of the Unconventional Resources

Category of Economic, Financial, or Cost Data	General Comments/Assumptions
Investment Costs	
. Exploration	. Estimated by the equation, $4 \times \left[\frac{1-P(S)}{P(S)}\right] \times \left[\frac{\text{Spacing}}{23{,}040}\right] \times$ Dry Hole Costs where: - P(S) is the likelihood of successful drilling and is determined on a basin specific basis - Spacing is the number of acres drained by one well - 23,040 acres = (36 square miles/township) x (640 acres per square mile)
. Drilling and Completion	. Estimated by the equation, $\left\{e^{[\text{intercept} + (\text{slope} \times \text{depth})]}\right\} \times \left\{\text{drilling and completion multiplier}\right\}$. 1975 Joint Association Survey published data reported on a state and substate district basis were updated by appropriate inflation multipliers
. Dry Hole	. Dry hole costs for lenticular sands computed by equation, (dry hole rate) x (drilling and completion + stimulation costs) where: - 0.30 was estimated Base Case dry hole rate - 0.20 was estimated Advanced Case dry hole rate

DRAFT

EXHIBIT II-8
(Continued)

Category of Economic, Financial, or Cost Data (Continued)	General Comments/Assumptions (Continued)
	. Dry hole costs for blanket formations computed by equation, (dry hole rate) x (0.8) x (drilling and completion costs) where: - 0.20 was estimated Base Case dry hole rate - 0.10 was estimated Advanced Case dry hole rate
. Stimulation	. Current estimates of fracturing costs obtained from a major service company
	. Linear fracture costs equations formulated for tight gas sands via regression analysis
	. Linear fracture cost model formulated for Devonian shale based on production company records; equation formulated was, Fracture cost = $23,500 + (3.12)x (depth in feet) where the constant term ($23,500) includes hauling, cementing, CBL logs, separator, tool rental, clean-up, and a 1,000 bbl sand/water fracture and the variable term [(3.12)(depth in feet)] reflects the cost of the required 4 inch casing
. Lease and Well Equipment	. Historical lease and well equipment costs on a region/basin basis were developed through 1974 and updated to June 1977 levels by appropriate inflation multipliers
. Compressor Equipment	. Estimated by the equation, $(\$440) \times (108) \times \left[\frac{\text{Sum of production in the first 3 years}}{(3) \times (365) \times (1{,}000 \text{ bbl})}\right]$

DRAFT

EXHIBIT II-8
(Continued)

Category of Economic, Financial, or Cost Data (Continued)	General Comments/Assumptions (Continued)
	where: - \$440 is investment cost of one installed horsepower - 108 is the estimated horsepower requirement for the compressor
	. No compressor costs included for Devonian Shales, because these costs were expected to be included in the rate base of the gas utilities
Operations and Maintenance Costs	
. Basic O&M Costs	. Estimates based on data from 2,000 wells
	. Costs include normal operating expenses, surface repairs, maintenance expenses, subsurface repairs and maintenance expense, field overhead, and ad valorem taxes
	. Annual costs were expressed as logarithmic functions of depth for each region according to the equation, 12 x [e intercept + (slope x depth)]
. Compressor Operating Costs	. Estimated according to the equation, (annual production) x [0.024 + (0.097) x (fuel price)] where: - 0.024 is the estimated incremental operating and maintenance costs of a two stage compressor (estimated at \$0.012 per Mcf/per stage) - (.097 x fuel cost) is the estimated fuel costs for the Btu requirements

DRAFT

EXHIBIT II-8
(Continued)

Category of Economic, Financial, or Cost Data (Continued)	General Comments/Assumptions (Continued)
Royalties	. Estimated at 12.5 percent of gross-value of production and paid in the year produced
Severance Taxes	. Estimated based on current state severance tax rates and based on value of production after royalty
Allocation of General and Administrative Costs	. Estimated as 20 percent of total operating and maintenance costs plus 10 percent of investment costs (in the year of investment)
Tangible Costs, Intangible Costs, and Depreciation	. Tangible costs estimated at 30 percent of drilling and completion costs for production wells and depreciated using the unit of production depreciation method . Intangible costs estimated at 70 percent of drilling and completion costs for production wells . Costs of stimulation, exploration, and dry holes are expensed
Federal and State Income Taxes	. Federal income tax rate of 48 percent applied; Federal taxes reduced by accrued investment tax credits . State income taxes calculated using current rates
Capital Investment Criteria and Thresholds	. Net present value criteria used for tight gas sands and Devonian Shales; nominal discount rates of 26 percent and 16 percent were used in the Base and Advanced Cases respectively

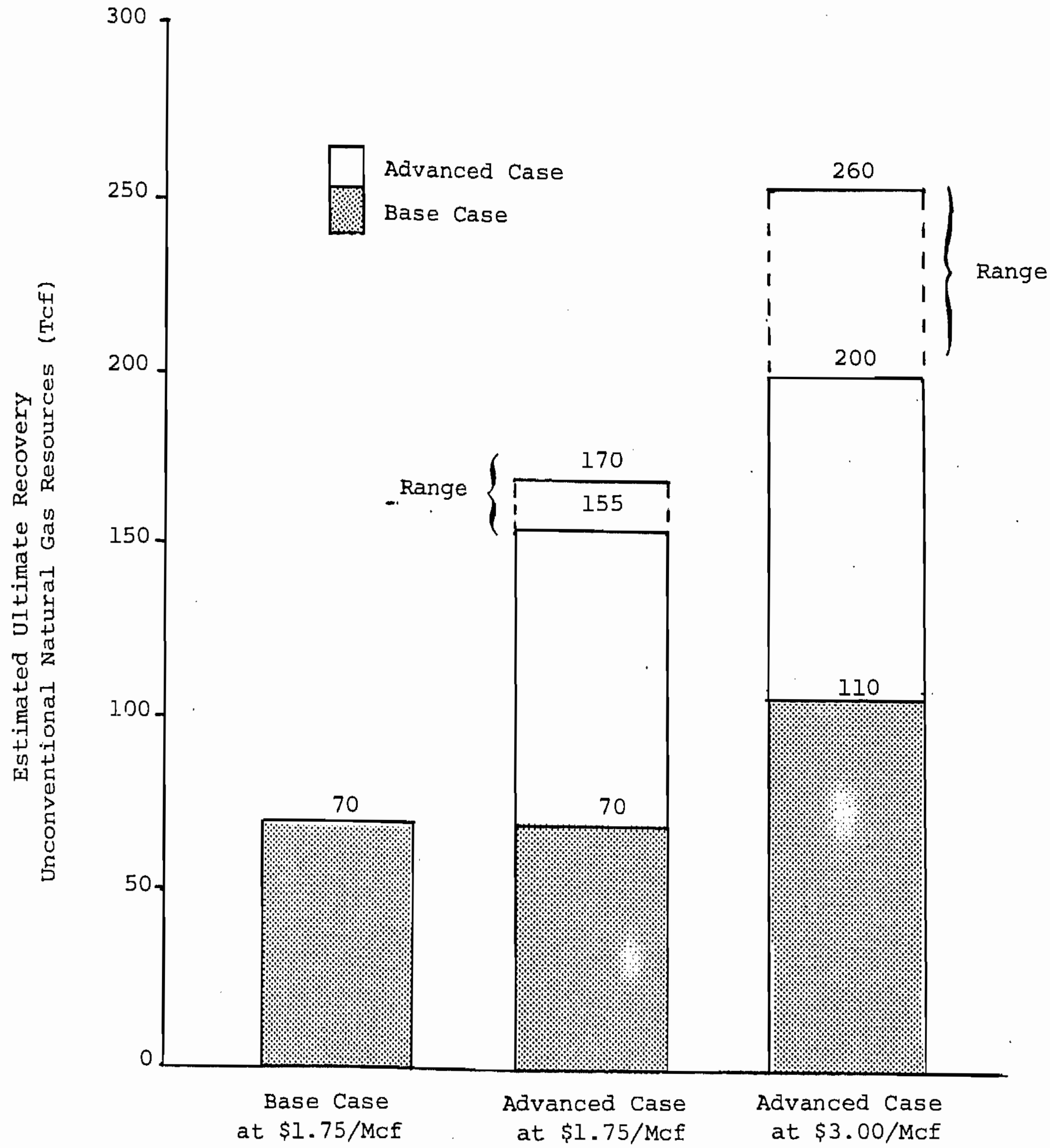
DRAFT

EXHIBIT II-8
(Continued)

Category of Economic, Financial, or Cost Data (Continued)	General Comments/Assumptions (Continued)
	. Payback criteria used for geopressured aquifers and methane from coal; threshold level used was maximum 10 year payback
Natural Gas Prices	. Three price levels employed ($1.75, 3.00, and 4.50 per Mcf); price stated in 1977 dollars and assumed maintained in constant dollars throughout analysis period

DRAFT

EXHIBIT II-9
The Potential of Gas From Unconventional Sources



DRAFT

provide a threshold price for beginning production from geopressured aquifers and methane from coal. In the tight gas basins, it will enable industry to exploit the more difficult portions of the target. As shown in Exhibits II-10 and II-11, the unconventional gas resources, already providing about 1 Tcf per year, could provide (under advanced technology and acceleration) from 3 to 4 Tcf in 1985 and from 6 to 8 Tcf in 1990 (at $1.75 and $3.00 per Mcf, respectively). Thus, unconventional sources of natural gas could be an important and economically attractive source for additional domestic gas supplies. The results of the analysis (summarized above) are presented below for each of the four unconventional resource areas.

(1) Tight Gas Sands

Production from the tight gas basins was found to be sensitive to increases in gas price and to advances in technology (Exhibits II-12 and II-13). Under current and near-term (Base Case) technology, industry is expected to produce substantial quantities of natural gas from these basins. At $1.75 per Mcf, nearly 70 Tcf will ultimately be recovered; annual production by 1990 is expected to exceed 2 Tcf. Improvements in the technology (Advanced Case) further increase recovery to 150 Tcf at $1.75 per Mcf and to 180 Tcf at $3.00 Tcf. Ultimate recovery then becomes relatively insensitive to price after this point. Technological advances also increase the annual rate of production by 1990 to 6.3 Tcf ($1.75 per Mcf) and to 7.7 Tcf ($3.00 per Mcf). Higher prices beyond $3.00 per Mcf add little to the 1990 production rate.

(2) Devonian Shales

As in the tight gas basins, ultimate recovery and production appear sensitive to gas price and technology (Exhibits II-14 and II-15). As shown in the exhibits, additions to ultimate recovery range from less than 2 Tcf ($1.75 per Mcf) to about 8 Tcf. At $4.50 per Mcf, ultimate recovery increases to 10.5 Tcf in the Base Case. Base Case annual production in 1990 increases from 0.1 Tcf at $1.75 per Mcf to about 0.3 Tcf at $3.00 per Mcf.

Under the Advanced Case assumptions, ultimate recovery at $1.75 per Mcf increases from 2 Tcf to over 4 Tcf in the Base Case. At $3.00 per Mcf, ultimate

DRAFT

EXHIBIT II-10
Total Domestic Gas Supply—
Conventional and Unconventional Sources
(at Gas Prices of $1.75/Mcf and
Current Technology)

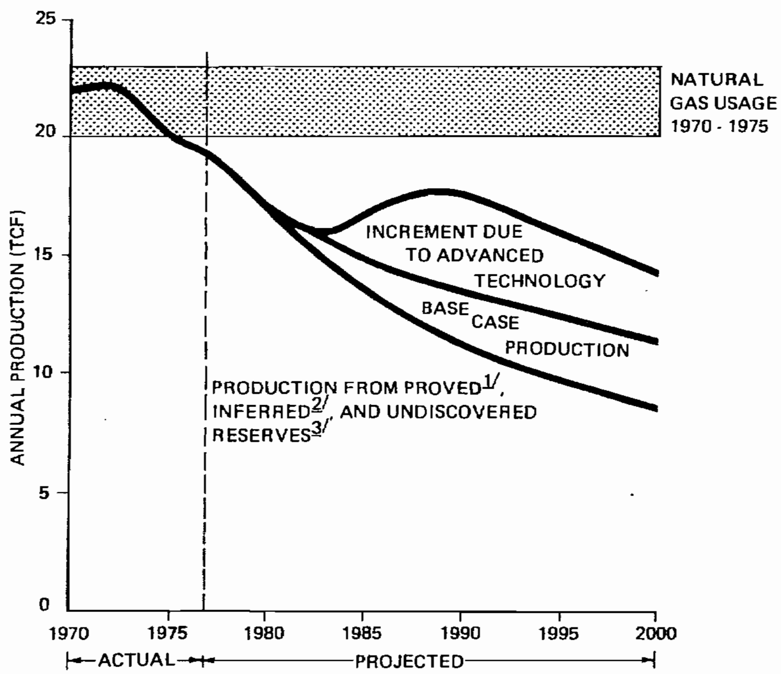
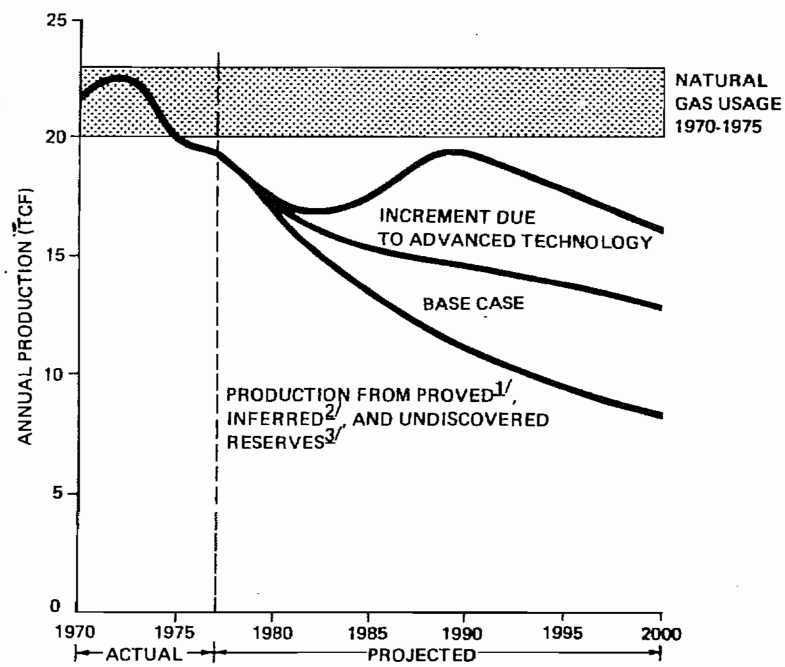


EXHIBIT II-11
The Potential of Unconventional Gas
Sources Under Advanced Technology
(at Gas Prices of $3.00/Mcf4)



1/ RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS AND NATURAL GAS IN THE UNITED STATES AND CANADA AS OF DECEMBER 31, 1976, BY AGA/API/CPA.
2/ BASED ON A RECENT LEWIN AND ASSOCIATES, INC., STUDY, ANALYSIS OF THE TIMING AND TOTAL OF INFERRED RESERVES OF NATURAL GAS IN THE CONTIGUOUS UNITED STATES, BY J. BRASHEAR AND F. MORRA.
3/ BASED ON ONSHORE (LOWER 48) DISCOVERIES OF 1.0 TCF/YEAR AND OFFSHORE (LOWER 48) DISCOVERIES OF 0.5 TCF/YEAR, GROWING TO 3.9 AND 1.9 TCF RESPECTIVELY THROUGH DEVELOPMENTAL DRILLING.
4/ CONVENTIONAL SOURCE GAS IS ESTIMATED AT $1.75 PER MCF.

EXHIBIT II-12
Base and Advanced Case Ultimate Recovery
From the Tight Gas Basins at Three Prices

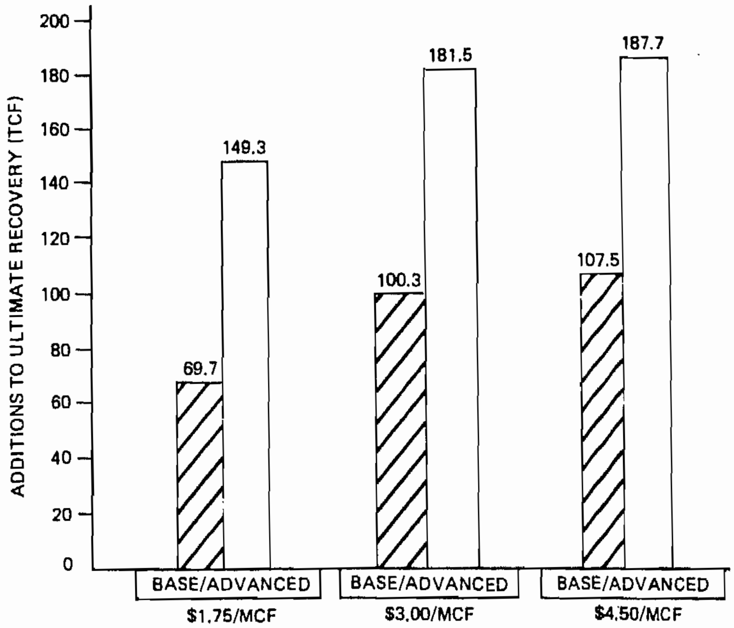
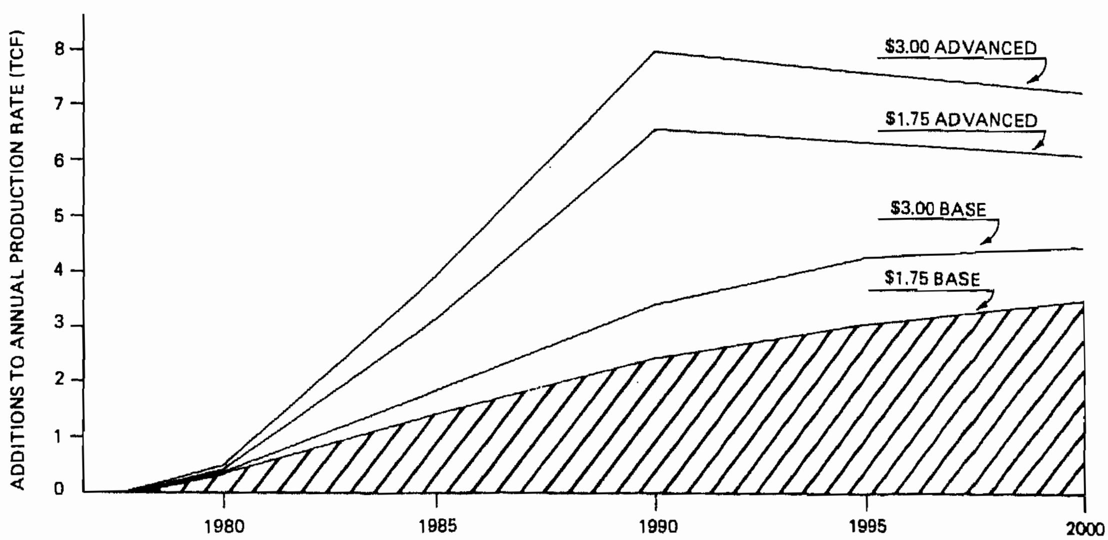


EXHIBIT II-13
Annual Production From the Tight Gas Basins to the
Year 2000 (At $1.75 and $3.00 Per Mcf)



DRAFT

EXHIBIT II-14
Devonian Shale Ultimate Recovery (at Three Gas Prices)

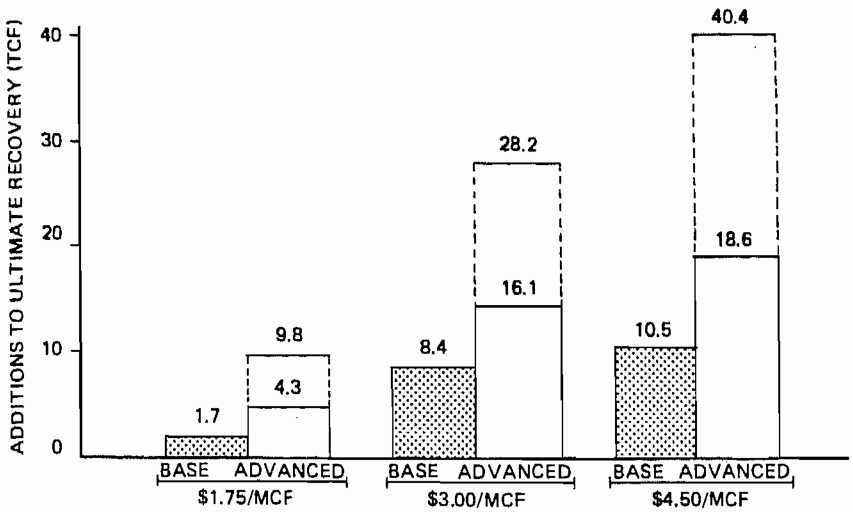
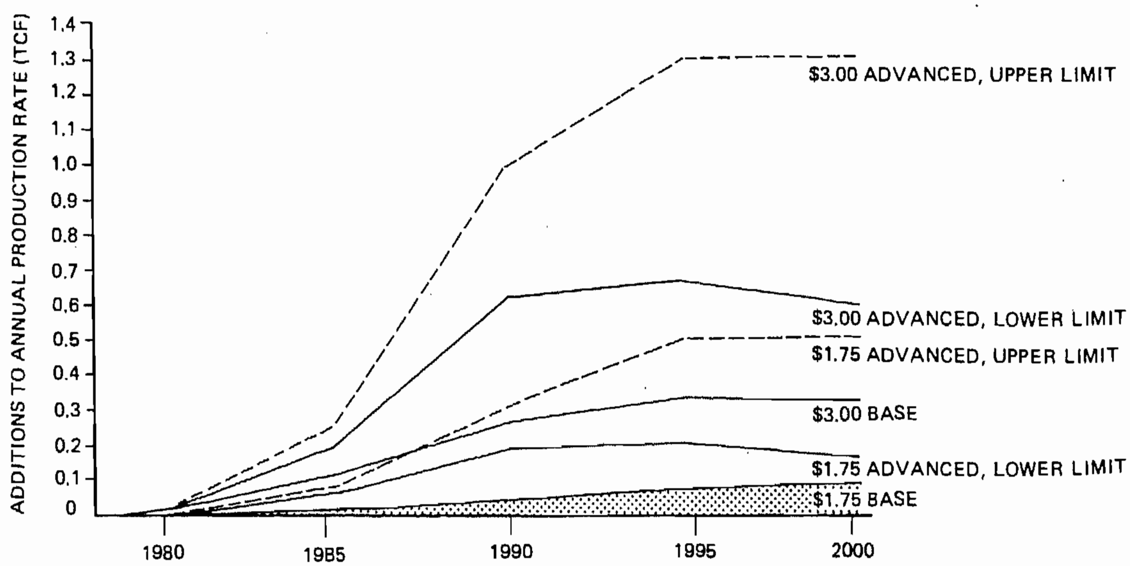


EXHIBIT II-15
Annual Production From the Devonian Shale
to the Year 2000 (at $1.75 and $3.00 per Mcf)



[1]DUE TO SIGNIFICANT UNCERTAINTIES IN KEY GEOLOGICAL AND ENGINEERING PARAMETERS, ADVANCED CASE PRODUCTION ESTIMATES ARE ESTIMATED IN TERMS OF RANGES AS OPPOSED TO POINT ESTIMATES.

DRAFT

recovery rises to 16 Tcf (versus about 8 Tcf in the Base Case). At $4.50 per Mcf, ultimate recovery would range from 18 to 40 Tcf. This range reflects geological uncertainties in the possible areas where little is known about the intensity of the natural fracture system. Advanced Case annual production in 1990 is estimated at 0.2 to 0.3 Tcf ($1.75 per Mcf). Increased price ($3.00 per Mcf) is estimated to increase annual production in 1990 to approximately 0.6 to 1.0 Tcf.

(3) Methane From Coal Seams

In general, the Appalachian Basin coal seams are too thin and too lean in methane content to support methane recovery economically on their own. Any estimates of recovery need to parallel closely the pace of mining and the opening of new mines. Assuming a vigorous installation of methane emissions recovery facilities in the "gassy" coal mines, the following production benefits could accrue:

Recovery/Production	Price Per Mcf		
	$1.75	$3.00	$4.50
Ultimate (30 Year) Recovery, in Tcf	1.1	1.6	1.6
Annual Production Rates, in Tcf/Year			
1985	0.02	0.02	0.02
1990	0.04	0.05	0.05
1995	0.04	0.07	0.07
Cumulative Recovery by the Year 1990, in Tcf	0.2	0.2	0.2

The analysis of methane recovery from deep, unminable coal seams using deviated wells provides the following estimates of recoverable methane as a function of natural gas price:

Price/Mcf	Recoverable Methane (Tcf)
$1.75	0-10
$3.00	0-20
$4.50	0-25

DRAFT

Because of the speculative nature of the resource base and the uncertain capacity of existing technology to exploit it economically, only a range of estimated recovery can be made at this time. No estimates have been made of production rates. All of the recovery is assumed to accrue from a joint public-private research and development program since there is little evidence of Base Case activity.

(4) Geopressured Aquifers

Although estimates of the gas-in-place in these reservoirs have been large, the essential question was not the total size of the resource but the portion that may be technically and economically recoverable. The analysis of the available data on the geopressured resources base[1] provided the following estimates of economic potential as a function of gas price:

Recoverable Gas	Total
Technically Recoverable Gas-in-Place (Tcf)	60
Economically Recoverable Gas at:	
$1.75/Mcf	0
$3.00/Mcf	1.0-28.0
$4.50/Mcf	5.0-43.0

1 Beyond the quantities estimated from using available resource data, still greater potential may exist in Texas and central Louisiana. Further, the research work on geopressured methane has intimated a second resource target that may be associated with geopressured aquifers—free methane in excess of that in the saturated reservoir brines. Should either of these conditions be proved by further research, the economic potential of geopressured aquifers may substantially increase.

Because of the very preliminary state of development of this resource, no production rates have been projected. It is unlikely that these resources will be developed without continued, active collaborative government-industry research and development.

* * * * *

As indicated in Exhibit 10 of the Executive Summary, the next step in the strategic analysis was the development of the specific R&D strategy and candidate projects which could unlock cost-effectively the estimated potential of the unconventional gas resources. Chapter III focuses on this step of the analysis.

DRAFT

III. STRATEGY FORMULATION AND CANDIDATE PROJECT SET DEVELOPMENT

1. INTRODUCTION

The purpose of the strategy formulation and project development section was to identify specifically and characterize a set of feasible EGR projects that have the greatest likelihood for realizing the potential of the unconventional gas resources. As shown in Exhibit 10 of the Executive Summary, there were four steps to accomplish the objective as follows:

- Identify major constraints to development
- Formulate strategies to overcome the constraints
- Determine a set of high-potential projects
- Completely characterize projects in terms of their primary attributes.

2. IDENTIFICATION OF MAJOR CONSTRAINTS TO FULL-SCALE EXPLOITATION OF UNCONVENTIONAL RESOURCES

The survey of the natural gas industry provided the primary input into the identification of the major constraints to full-scale exploitation of the unconventional resources. The industry survey focused on utilization and expansion of the current DOE/Bureau of Mines (BOM) interface with the natural gas and coal mining industries. Senior administrative, financial, and technical executives, representing 92 firms in the production, transmission, distribution, and mining segments of gas and coal industries, were interviewed. These executives were instrumental in monitoring their companies' interface with the Federal Government concerning enhanced gas recovery, shaping their firm's capital investment strategy, and formulating appropriate programs.

Open-ended discussions with a wide variety of these corporate representatives resulted in the identification of the following five major categories of constraints or barriers to increased exploitation of the unconventional resources:

DRAFT

- Technical risks
- Economic/capital market constraints
- Materials and equipment availability
- Environmental constraints
- Institutional and other external constraints.

In general, institutional and other external factors were stressed as most seriously constraining full exploitation of the unconventional resources. Price regulation, lack of stable national energy policy, and uncertainties over future Federal regulatory and environmental policies were identified as major problem areas. Technical risks were also identified as possible major constraints but did not approach the level of priority assigned to the institutional factors. Economic and capital market constraints and environmental constraints were given equal significance but less important when compared to technical constraints. Materials and equipment availability were identified as least significant and were stressed as near-term impacts. These detailed results of the identification and assessment focus of constraints are described below for each of the four unconventional resource areas.

(1) Geopressured Aquifers

Geopressured aquifers were singled out by industry as the unconventional resource possessing the greatest constraints to full-scale commercialization. The institutional, technical, and environmental risks and constraints were considered by industry as being comparable in severity. The most important individual problems identified included:

- Corrosion, subsidence, and reinjection
- Insufficient reservoir sizes to generate favorable economics
- Water disposal
- Artificially depressed prices for natural gas.

The other categories of constraints were considered much less important.

(2) Methane From Coal Seams

This unconventional resource area was identified by industry as the second most difficult area in terms of the existence of significant constraints and barriers to full-scale exploitation. In total, the constraints were considered as being much more significant than those incurred in the Devonian shales and tight gas sands. Economic/capital market and institutional constraints were considered more significant than technical and environmental constraints. Major problem areas and uncertainties identified by industry included the following:

- Gas ownership problem
- Stringency of Mine Safety & Health Administration and state safety regulations
- Marginal economics in all but very "hot" mines
- Limited markets—lack of nearby pipelines or internal use.

(3) Devonian Shales

The Devonian shales ranked next in terms of the severity of identified barriers to full-scale exploitation of the resource. Institutional constraints, particularly regulated price, were stressed as being significantly more important than any of the other classes of constraints, risks, or obstacles. These institutional constraints included:

- Marginal economics (based on current price), rather than technology, was considered the major obstacle to development.
- Many firms stated that an increase in gas prices to the $2.00-2.50/Mcf range would lead them either to initiate or to increase their activity significantly in the Devonian shales.

DRAFT

Technical risks were cited as the second most important set of constraints and were followed by economic and capital market constraints. Examples of specific technical risks are as follows:

- Uncertainty over the size of the resource base and suspicion that the recoverable reserves are much lower than currently estimated were considered to be the major technical risks.

- Problems caused by hydraulic fracturing in shale because of the effects of water on the clay were also cited as major technical problems.

The remaining categories of constraints were identified as approximately comparable in severity.

(4) Tight Gas Sands

This unconventional resource area was identified by industry as having the least severe constraints to full-scale exploitation. Institutional constraints were stressed as the most significant. Lack of trained manpower and insufficient price for gas were identified as two general constraints.

Technical risks and environmental constraints were identified as comparable in severity. Major technical problems included the following:

- Heterogeneous reservoirs with different lateral and vertical conditions

- Uncertainty over the resource base—reservoir locations and gas-in-place

- Inability to keep the fracture in the pay zone.

Environmental issues, equipment/materials availability, and economic/capital market constraints were not seen as major or insurmountable problems.

3. SPECIFICATION OF R&D STRATEGIES/ACTIVITIES TO OVERCOME OR SUFFICIENTLY MITIGATE THE CONSTRAINTS

Six major categories of strategies[1] were developed to overcome or sufficiently mitigate the significant commercialization constraints identified in the previous step. These categories included the following:

- Resource characterization and appraisal
- Development of improved diagnostic tools
- Development and improvement of enhanced gas recovery technology
- Testing the demonstration of improved enhanced gas recovery technology
- Overcoming enhanced gas recovery nonprocess constraints
- Stimulation of technology transfer.

4. COMBINING STRATEGIES WITH HIGH-POTENTIAL TARGETS TO PROVIDE CANDIDATE R&D PROJECT SET

The geologic, engineering, and production data from the "Resource Definition" and "Economic Evaluation of the Resource" steps of the strategic analysis were analyzed in more detail to identify a smaller set of high-potential target areas from each of the four unconventional resource areas.

The developed strategies were then "applied" to these high-potential target areas to formulate a specific set of candidate EGR projects. In this process, high-potential targets that were hindered by constraints that could not be sufficiently mitigated by the strategies were eliminated from further consideration. The resultant set of 21 candidate projects consisted of two primary categories, Group I projects and Group II projects. The 17 Group I projects

---

1 Six major categories were originally identified. During the development of the candidate set of projects, however, the six categories were condensed into four categories that were directly applicable to the high-potential targets.

DRAFT

consisted of the application of improved EGR technology to the possible and probable areas of the unconventional resources. The four Group II projects entailed the engineering/geologic characterization of the speculative portions of the unconventional resources. The primary objectives of the Group II projects are to obtain the necessary engineering and geologic data to assess reliably the economic potential of these speculative areas. The Group I and Group II projects are described in Exhibits III-1 and III-2.

5. COMPLETE SPECIFICATION AND CHARACTERIZATION OF CANDIDATE PROJECTS

After selection, the candidate projects were comprehensively characterized by two main factors: (1) the principal classes of R&D activities and (2) a homogeneous set of performance parameters (major costs, benefits, and impacts) which DOE program managers used as the primary basis for the allocation of Federal R&D dollars. For the Group I projects, these R&D activities included the following:

- Developing and implementing technology for resource characterization
- Conducting field tests to improve various EGR technologies
- Conducting recovery tests and performing economic studies to verify economic feasibility
- Disseminating all findings of the above activities to industry.

For Group II projects, the R&D activities were all related to in-depth characterization of the unconventional resource base. They included:

- Extensive review of published geologic and technical literature
- Collection of pertinent geologic and engineering data
- Resource characterization drilling.

EXHIBIT III-1
Group I Project Descriptions[1]

Unconventional Resource Area	Project Name	Target Area
Tight Gas Sands (See Exhibit III-3 for geographic locations)	. Tight, Blanket Gas Formations	Cotton Valley Trend (southern Arkansas, eastern Texas, northern Colorado Denver Basin (eastern Colorado) San Juan Basin (western Colorado and northwestern New Mexico) Wind River Basin (Wyoming) Quachita Mountains Province (central Arkansas and eastern Oklahoma)
	. Greater Green River Basin, Full Program	Greater Green River Basin (Wyoming)
	. Uinta Basin, Full Program	Uinta Basin (Utah)
	. Piceance Basin, Full Program	Piceance Basin (Colorado)
	. Other Tight Lenticular Sands	Sonora Basin (west Texas) Douglas Creek Arch (western Colorado) Big Horn Basin (northern Wyoming)
	. Low Permeability, Shallow Gas Sands	Williston Basin of the Northern Great Plains Province (Montana)
	. Tight, Shallow Gas Sands	Williston Basin of the Northern Great Plains Province (Montana)
	. Shallow Near Conventional Gas Sands	Williston Basin of the Northern Great Plains Province (Montana)
	. Other Low Permeability Reservoirs	Bruckner-Smackover Limestone of the Cotton Valley Trend (eastern Texas and northern Louisiana)
Devonian Shales (See Exhibit III-4 for geographic locations)	. Dual Completion of Marginal Devonian Shales - Ohio	Brown shale sequences of the Ohio Shale Formation (Ohio)
	. Deep Appalachian Front Area	Middle Devonian brown/black shales (W. Virginia, Penna.)
	. Define Potential of Deep Devonian Shales	Harrell and Marcellus Formations (Pennsylvania and New York)
	. Improve Recovery Efficiency in Productive Devonian Shale	Upper Devonian brown/black shales (eastern Kentucky and western West Virginia)
	. Other Devonian Shale Basins	Illinois Basin (western Kentucky southwestern Indiana and south central Illinois) Michigan Basin (Michigan, northern Indiana and Ohio)
Methane From Coal (See Exhibit III-5 for geographic locations)	. Methane From Minable Coal - Appalachian Basins	Pittsburgh, Pocahontas No. 3, Pratt, and Kittanning Coalbeds (Appalachia)
	. Methane From Unminable Coal	Deep Coal Deposits (Colorado, Wyoming, Utah, and New Mexico)
Geopressured Aquifers (See Exhibit III-6 for geographic locations)	. Geopressured Aquifers, Full Program	Tertiary Age Formations (Texas Gulf Coast) Miocene and Upper Cretaceous Formations (Louisiana and Mississippi Gulf Coast)

1 Refer to Appendix F for more thorough and detailed descriptions of Group I projects.

DRAFT

DRAFT

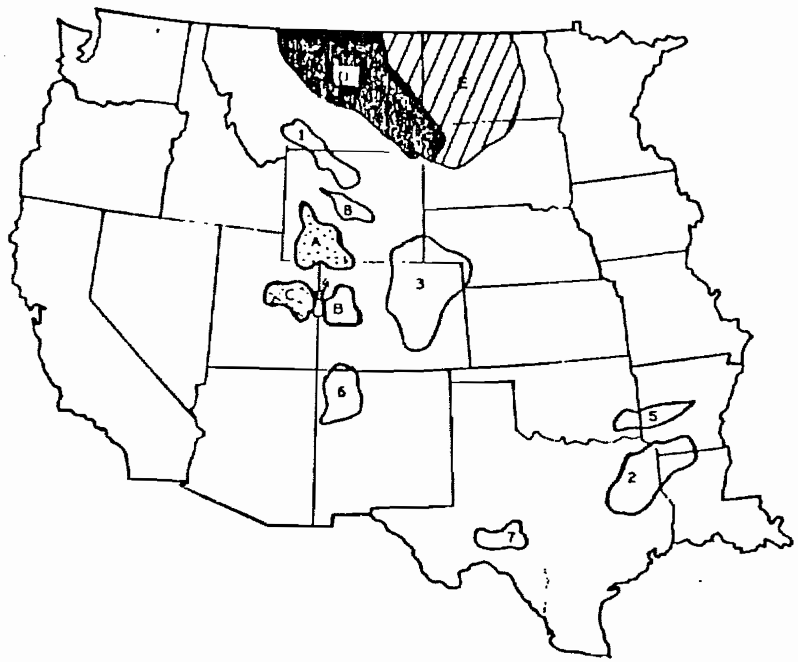
EXHIBIT III-2
Group II Project Descriptions[1]

Unconventional Resource Area	Project Name	Target Area
Tight Gas Sands (See Exhibit III-3 for geographic locations)	• Characterization of the Speculative Areas of Tight Gas Sands Formation	The target area consists of ten basins including the four Western Tight Basins, the Shallow Basins and five other basins with particularly difficult geological problems. Also, the six basins excluded previously from Group I for lack of data are included.
Devonian Shales (See Exhibit III-4 for geographic locations)	• Characterization of the Speculative Areas of Devonian Shales	The target area consists of the speculative areas of the Appalachian, Michigan, and Illinois Basins.
Methane From Coal (See Exhibit III-5 for geographic locations)	• Characterization of the Speculative Areas of Deep Coal Seams	The target area includes the deep and speculative unminable coal seams, predominantly in the West.
Geopressured Aquifers (See Exhibit III-6 for geographic locations)	• Characterization of the Speculative Areas of Geopressured Aquifer Zones	The target area consists of the speculative, onshore areas of south Louisiana and Coastal Texas.

1 Refer to Appendix F for more thorough and detailed descriptions of Group I projects.

DRAFT

EXHIBIT III-3
Locations of Major Tight Gas Sand Basins

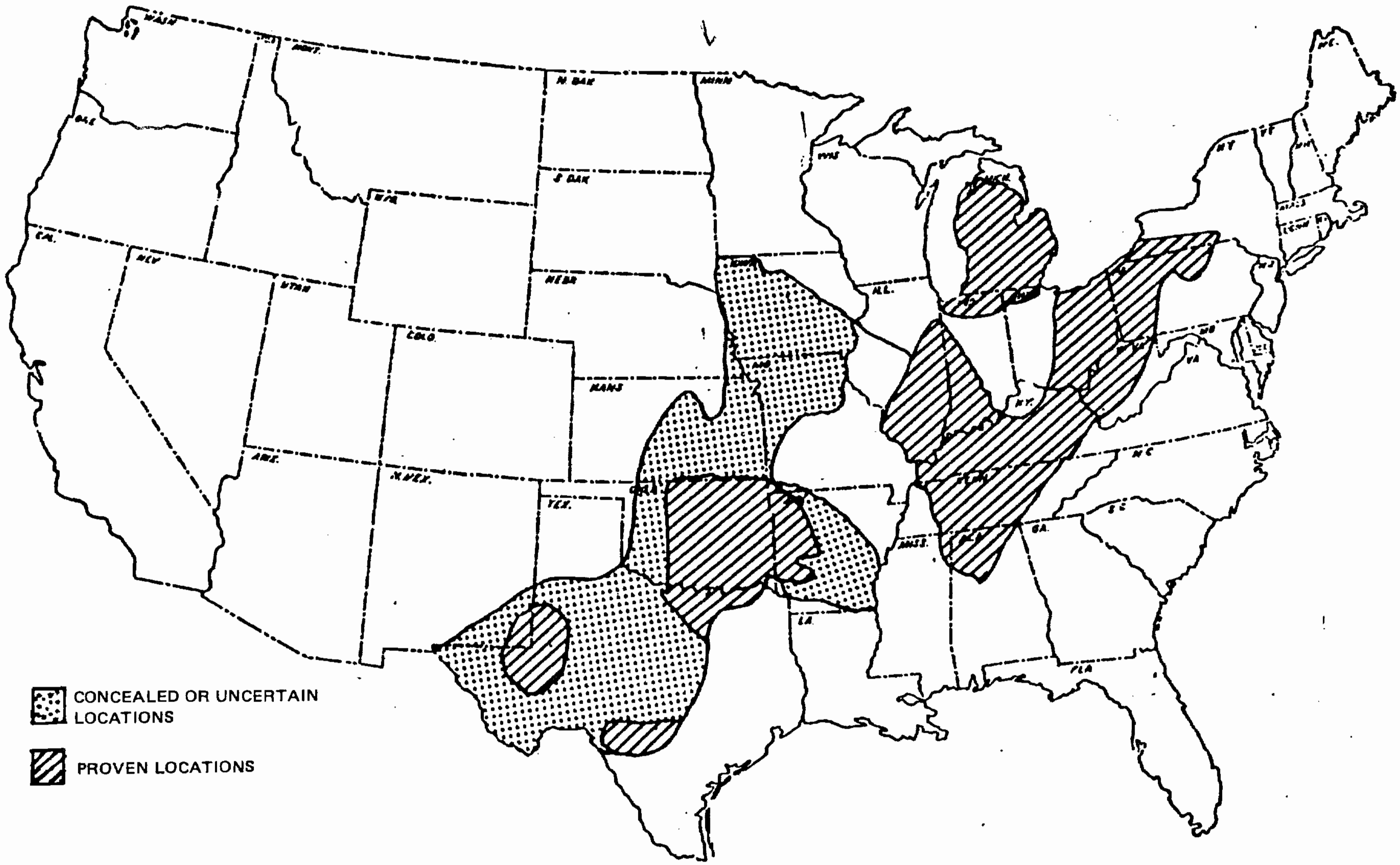


ERDA'S PRIMARY STUDY AREAS	GEOLOGICAL AREA
A. GREATER GREEN RIVER BASIN	TERTIARY AND CRETACEOUS
B. PICEANCE BASIN	TERTIARY AND CRETACEOUS
C. UINTA BASIN	TERTIARY AND CRETACEOUS
D. NORTHERN GREAT PLAINS PROVINCE	CRETACEOUS
E. WILLISTON BASIN	CRETACEOUS
ADDITIONAL LOW-PERMEABILITY AREAS IN THE STUDY	
1. BIG HORN BASIN	TERTIARY AND CRETACEOUS
2. COTTON VALLEY TREND	JURRASSIC
3. DENVER BASIN	CRETACEOUS
4. DOUGLAS CREEK ARCH	CRETACEOUS
5. DUACHITA MOUNTAINS PROVINCE	MISSISSIPPIAN
6. SAN JUAN BASIN	CRETACEOUS
7. SONORA BASIN	PENNSYLVANIAN
8. WIND RIVER BASIN	TERTIARY AND CRETACEOUS
OTHER LOW-PERMEABILITY AREAS NOT INCLUDED IN STUDY	
a. ANADARKO BASIN	PENNSYLVANIAN
b. ARKOMA BASIN	PENNSYLVANIAN
c. FORT WORTH BASIN	PENNSYLVANIAN
d. RATON BASIN	TERTIARY AND CRETACEOUS
e. SNAKE RIVER DOWNWARP	TERTIARY AND CRETACEOUS
f. WASATCH PLATEAU	CRETACEOUS
g. WESTERN GULF BASIN	TERTIARY AND CRETACEOUS

Source: U.S. ERDA, Western Gas Sands, Project Plan.

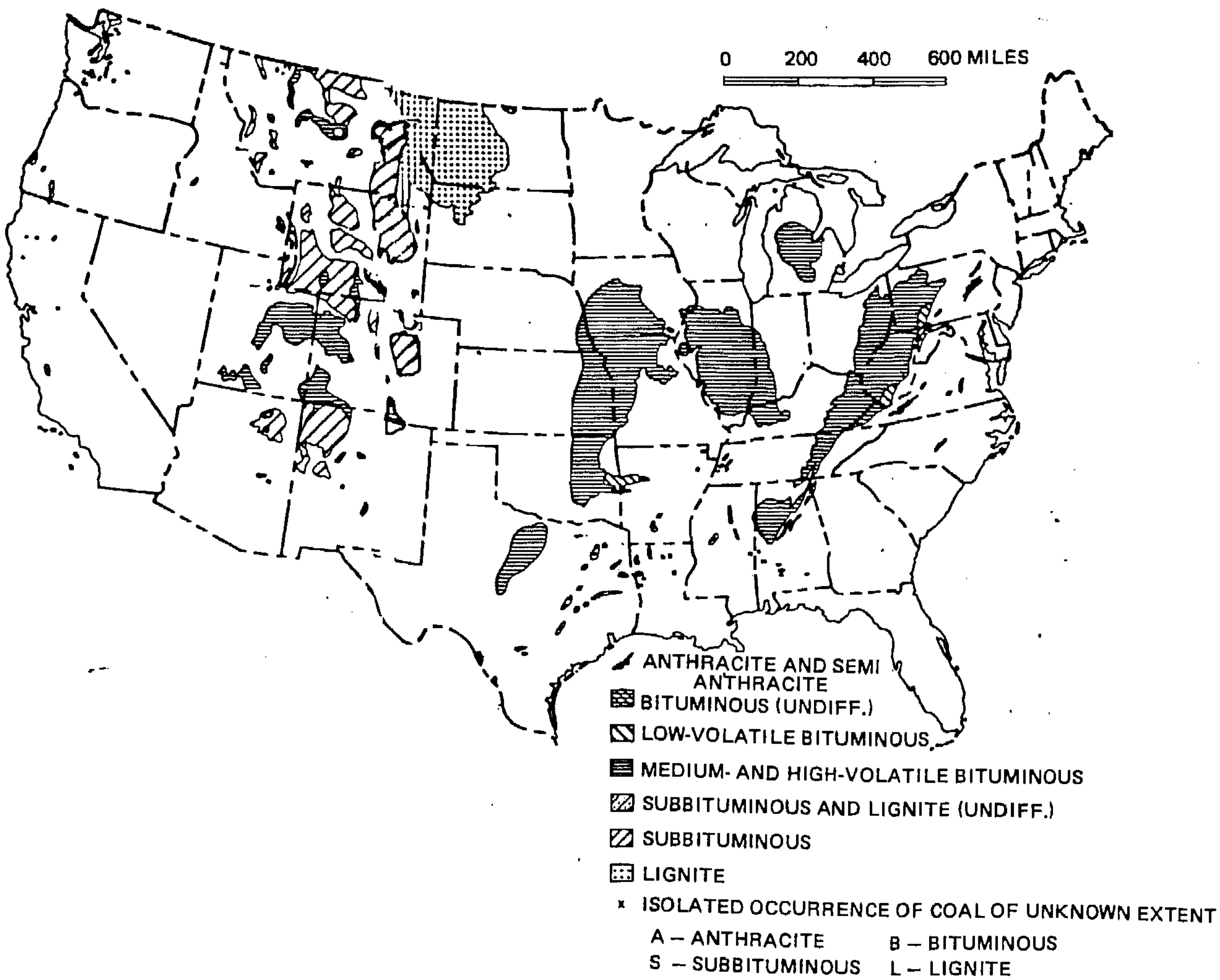
DRAFT

EXHIBIT III-4
Devonian Shale Deposits of the United States



SOURCE: U.S. ERDA PROJECT PLAN DOCUMENT FISCAL YEAR 1977. EASTERN GAS SHALES PROJECT, p. 4.

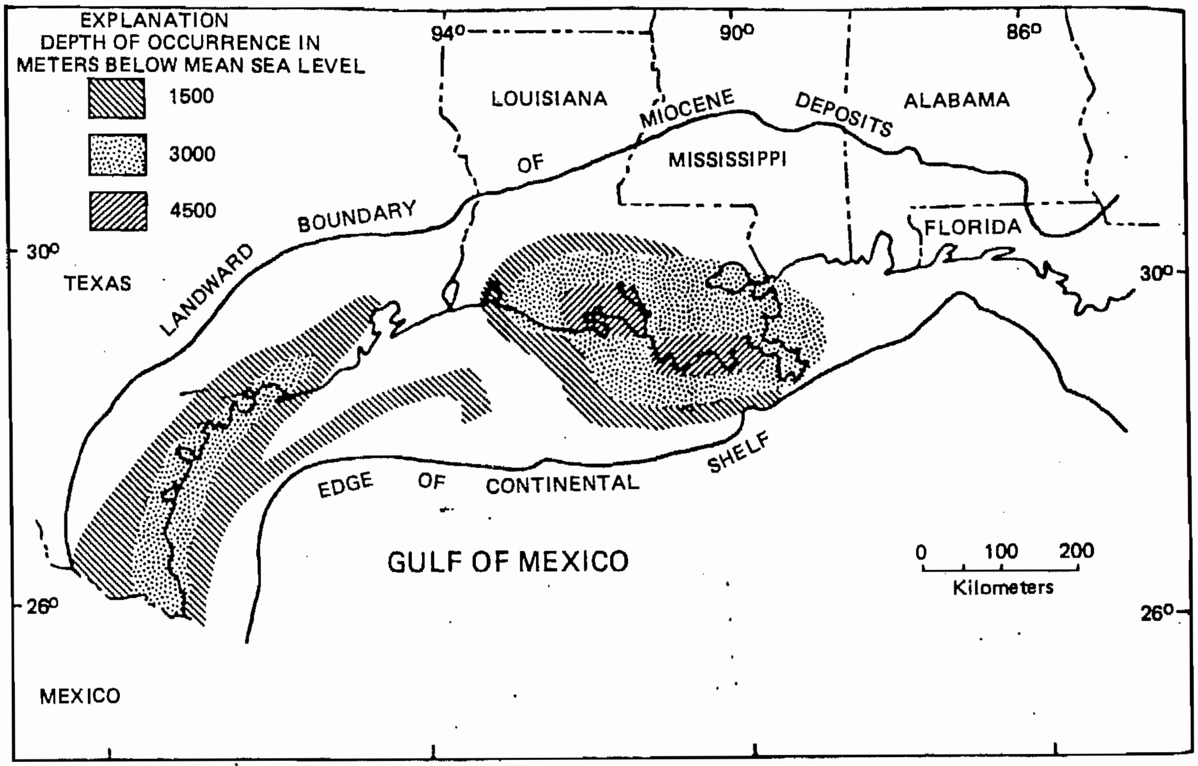
EXHIBIT III-5
Coal Deposits of the Continental United States



Source: Illinois State Geological Survey, Place of Coal in the Total Energy Needs of the United States, p. 4.

DRAFT

EXHIBIT III-6
Locations of Possible Geopressured Zones



SOURCE: D.G. BEBOUT, PROCEEDINGS OF SECOND GEOPRESSURED GEOTHERMAL ENERGY CONFERENCE, VOL. I, SUMMARY AND FUTURE PROJECTIONS, p. 6.

DRAFT

(1) Group I Performance Parameters

The homogeneous set of performance parameters used to characterize the Group I projects was developed on the basis of significant feedback from public sector managers involved in the formulation, management, and assessment of the EGR R&D program. The objective of this process was to select carefully those parameters which clearly depict the projects in terms of their ability to meet overall program objectives as well as to contribute to the realization of national goals in the natural gas area. Consequently, each of the candidate Group I projects was characterized in terms of six major performance parameters:

- Environmental impacts
- Socioeconomic impacts
- Incremental production
- Incremental ultimate recovery
- Direct DOE funding - 5-year budget
- Industry Base Case cumulative production.

These parameters are defined and described in detail in the ensuing paragraphs. In addition, the specific values of these performance parameters for each of the candidate Group I projects is presented in Exhibit III-7.

1. Environmental Impacts

Virtually all of the candidate Group I projects had associated environmental impacts of varying degrees. For purposes of the strategic analysis, it was impossible to quantify accurately all of the potential environmental impacts and estimate the costs required to overcome or mitigate the negative impacts potentially associated with full commercial-scale versions of the projects. Thus, the costs were represented in terms of a qualitative scale which reflected the ease (and thus the cost) of technology implementation from an environmental standpoint. The qualitative scale consisted of the following five broad classes of measurement:[1]

---

[1] Appendix G presents a description of the process by which the qualitative scale for environmental impacts was developed.

DRAFT

- Class I - Most Favorable: The proposed project will result in positive environmental benefits to the region affected.

- Class II - Favorable: The proposed project will not adversely impact regional environmental conditions.

- Class III - Slightly Unfavorable: The proposed project will result in temporary adverse environmental impacts.

- Class IV - Unfavorable: The proposed project will result in certain adverse but controllable environmental impacts. Special efforts will be required to reduce these impacts.

- Class V - Unachievable: The proposed project cannot be conducted because of the severity of environmental impacts or the strict regulations prohibiting such activity. (None of the Group I projects fell into this category.)

It was impossible to quantify the costs required to reduce the environmental impacts which may result with projects falling into Categories III and IV (no projects fall into Category V). Additional insight is provided, however, in column 2 of Exhibit III-7 by a listing (in the form of an alphabetic code) of the environmental factors which potentially may have the most severe impact on the full-scale commercialization of each project. The alphabetic code used is defined as follows:

A Water Requirement
B Water Disposal
C Gaseous Emissions
D Hazardous Substances
E Noise Levels
F Geohydrological Impacts
G Land Modifications
H Ecosystem Impacts
I Aesthetic Degradation

DRAFT

Unconventional Resource Area	Project Name	(1) Project No.	(2) Environmental Impact Class*	(3) Socioeconomic Impact Class*	Incremen		
					$1.75/Mcf		
					(4a) 1985	(4b) 1990	(1
Tight Gas Sands	Low-Permeability, Shallow Gas Sands	1	III C	IV A,B	0.0	0.0	
Methane from Coal	Methane from Mineable Coal Appalachian Basins	2	III B	III F	< 0.05	< 0.05	<
Tight Gas Sands	Tight Blanket Gas Formations	3	III C	III A	0.6	1.5	
		4	II	III A	0.0	0.1	
Geopressured Aquifers	Geopressured Aquifer, Full Program	5	IV G,H	I	NA**	NA	
Tight Gas Sands	Other Low Permeability Reservoirs	6	II	II	0.0	0.1	
Tight Gas Sands	Tight, Shallow Gas Sands	7	III C	IV A,B	0.0	0.0	
Devonian Shale	Dual Completion of Marginal Devonian Shales Ohio	8	IV B,C	III G	0.1	0.2	
Tight Gas Sands	Greater Green River Basin Full Program	9	III A	IV A,B	0.4	0.8	
Tight Gas Sands	Piceance Basin, Full Program	10	III A	IV A,B	0.1	0.2	
Methane from Coal	Methane from Unminable Coal	11	III A	IV A,B	NA**	NA	
Devonian Shale	Deep Appalachian Front Area	12	III B	IV F,G	0.0- <.05	0.0-0.1	0.
Devonian Shale	Define Potential of Deep Devonian Shales	13	III B	III F	0.0	0.0	
Tight Gas Sands	Shallow, Near Conventional Gas Sands	14	III C	IV A,B	0.1	0.2	<
Tight Gas Sands	Other Tight Lenticular Sands	15	II	III A	0.1	0.4	
Devonian Shale	Improve Recovery Efficiency in Productive Devonian Shales	16	III B	III F	0.0	0.0	
Tight Gas Sands	Uinta Basin, Full Program	17	III A	IV A,B	0.5	0.8	
Devonian Shale	Other Devonian Shale Basins	18	III B	II	0.0-0.5	0.0-0.2	0.

*Class -
I Most Favorable
II Favorable
III Slightly Unfavorable
IV Unfavorable
V Unachievable

**NA = Not Availabl

EXHIBIT III-7

Performance Parameters for Group I Projects

SURVEY FORM

Performance Parameters								
(4) ental Annual Production (Tcf)				(5) Direct DOE Funding - 5 Year Budget (Millions of Constant 1977 $)	(6) Incremental Ultimate Recovery (Tcf)			(7) Industry Base Case Cumulative Production by 1990 at $1.75/Mcf
	$3.00/Mcf							
(4c) 1995	(4d) 1985	(4e) 1990	(4f) 1995		(6a) $1.75/Mcf	(6b) $3.00/Mcf	(6c) $4.50/Mcf	
0.2	0.0	0.0	0.2	6.2	1.3	1.3	1.3	0.2
< 0.05	< 0.05	0.1	0.1	26.2	1.1	1.6	1.6	0.0
1.2	0.4	1.2	0.8	25.0	27.4	15.2	15.5	5.9
0.1	0.1	0.1	0.1	68.0	1.5	2.6	3.8	1.1
NA	NA	NA	NA	100.9	0.0	1.0 - 28.0	6.0 - 37.0	0.0
0.0	0.1	0.3	0.2	6.5	0.9	5.1	1.6	1.0
0.0	< 0.05	0.1	0.2	9.3	0.0	7.6	10.0	0.0
0.1	0.1	0.3	0.3	29.3	2.6	6.0	6.0 - 8.8	< 0.05
0.6	0.4	0.9	0.7	44.7	14.8	16.7	16.3	0.8
0.2	0.2	0.5	0.3	29.8	5.0	8.6	10.3	0.1
NA	NA	NA	NA	24.1	0.0-10.0	0.0-20.0	0.0-25.0	0.0
0.0-0.1	0.0-0.1	0.0-0.2	0.0-0.2	6.5	0.0-1.8	0.0-4.5	0.0-4.5	0.0
0.0	0.0	0.0	0.0	25.1	0.0	0.0	0.0-6.7	0.0
< 0.05	0.1	0.3	< 0.05	5.5	0.8	2.3	1.7	4.0
0.6	< 0.05	0.2	0.3	17.8	15.5	8.9	8.3	1.5
0.0	0.1	0.2	0.1	10.0	0.0	1.7	2.1	0.0
0.5	0.5	1.0	0.6	44.8	13.9	15.5	15.3	0.4
0.0-0.2	0.0-0.1	0.0-0.4	0.0-0.3	22.4	0.0-3.7	0.0-7.6	0.0-7.6	0.0

ble (could not be estimated due to significant uncertainties in the resource base and its technological development)

2. Socioeconomic Impacts

As in the case of environmental factors, the candidate Group I projects have associated with their commercial-scale development a wide variety of socioeconomic effects which potentially impact directly on their development and full-scale commercialization. While the DOE program in EGR cannot be expected to mitigate directly or overcome negative socioeconomic impacts only through technology development funding, the internal allocation of these dollar resources must take full cognizance of the level of these potential socioeconomic effects and potential impacts on commercialization of the EGR technology.

The socioeconomic parameter was specified as a qualitative scale which consists of the following five broad categories of measurement:[1]

- Class I - Most Favorable: The proposed project will result in positive socioeconomic benefits to the region affected.
- Class II - Favorable: The proposed project will not adversely impact regional socioeconomic conditions.
- Class III - Slightly Unfavorable: The proposed project will result in temporary adverse socioeconomic impacts.
- Class IV - Unfavorable: The proposed project will result in certain adverse but controllable socioeconomic impacts. Special efforts will be required to reduce these impacts.
- Class V - Unachievable: The proposed program cannot be conducted due to the severity of socioeconomic impacts or to strict regulation prohibiting such activity. (None of the Group I projects fell into this category.)

---

1 See Appendix G for a description of the process by which the qualitative scale for socioeconomic impacts was developed.

As in the case of the environmental impacts, it was impossible to quantify the public sector costs which may be required to mitigate some of the more adverse socioeconomic impacts which may result with projects falling into Categories III and IV (no projects fell into Category V). Additional insight, however, is provided in column 3 of Exhibit III-7 by a listing (in the form of an alphabetic code) of the socioeconomic factors which may potentially have the most severe impact on the full-scale commercialization of each project. The alphabetic code used is defined as follows:

A	Labor Force Requirements
B	Population Impacts
C	Income Level
D	Housing
E	Commercial and Service Facilities
F	Local Government
G	Community Services
H	Transportation
I	Land Use
J	Infrastructure

3. Incremental Production

Production benefits are industry's anticipated exploitation of the resource, given the increased geologic understanding and advancement of the technology that would result from accomplishing the goals of the respective projects. The estimates are incremental in that they are over and above the Base Case levels of exploitation expected to be accomplished by industry in the absence of a Federal technology development program.

The numbers in columns 4a-4f of Exhibit III-7 are point estimates (and, in some cases, ranges) of the annual incremental production at three key dates (1985, 1990, and 1995) resulting from DOE-sponsored technology development. The numbers are expressed in trillions of standard cubic feet (Tcf)[1] and are presented for two price levels [$1.75 per thousand cubic feet (Mcf) and $3.00 per Mcf].

---

[1] One Tcf is approximately equivalent to one quad.

DRAFT

4. Incremental Ultimate Recovery

Incremental ultimate recovery is the total anticipated incremental reserve additions from a target resource that would result from accomplishment of the goals of the respective projects. As such, it is a suitable measure of maximum potential benefits of a particular technology development project.

The numbers in column 6 of Exhibit III-7 represent point estimates (in some cases, ranges) of the anticipated incremental recovery resulting from DOE-sponsored technology development. Again, they represent recovery (expressed in Tcf) above and beyond that expected from industry's efforts (Base Case), excluding any DOE technology development funding.

5. Direct DOE Funding - 5-Year Budget

The number in column 5 of Exhibit III-7 represents the total 5-year DOE budget required for each candidate EGR project. The numbers are expressed in terms of millions of 1977 constant dollars and do not include the industry portion of those candidate projects which are cost-shared. As discussed previously, these DOE funding levels do not include the costs to reduce the environmental impacts (if any) which may result in some projects, nor do they address the public sector costs which may be required to mitigate some of the more adverse socioeconomic impacts which may result.

6. Industry Base Case Cumulative Production

This performance parameter represents the cumulative production (from now until 1990) anticipated to be realized on the basis of private sector activity in the absence of a Federal technology development program. The parameter is an indicator of anticipated industry (Base Case) exploitation of the resource.

DRAFT

7. Other Project Impacts

The set of performance parameters previously described are important from a standpoint of project characterization and differentiation. The set, however, is recognized as not being comprehensive. Other potential benefits of these projects, such as increased technical knowledge, could not be easily measured and then translated into manageable terms. The majority of the parameters excluded from direct measurement tended to be qualitative in nature and were thus considered when arriving at a final recommended EGR program.

(2) Group II Performance Parameters

The Group II projects were characterized on the basis of four performance parameters as shown in Exhibit III-8:

- Gas-in-place
- Technically recoverable gas
- Speculative area
- Direct DOE funding - 5-year budget.

The parameters are described in the following sections.

1. Gas-in-Place

These estimates were based on a simple volumetric analysis—gas content per unit volume multiplied by volume of material. This parameter presented "upper bound" estimates of the overall potential of the speculative portions of the unconventional resources but did not address the technical and economic feasibility of recovery.

2. Technically Recoverable Gas

The amount of technically recoverable gas was determined by applying the ratio of cumulative production/gas-in-place values for each Group I area to the range of gas-in-place for each Group II area. The parameter thus presents (by analogy) very rough estimates of the volume of gas recoverable with current technology but did not consider the economics of such potential recovery.

DRAFT

DRAFT

EXHIBIT III-8
Performance Parameters for Group II Projects

Resource Area	Project Name	DOE Funding 5-Year Budget (Millions of Constant 1977 $)	Speculative Area (Square Miles)	Gas-In-Place (Tcf)	Technically Recoverable Gas (Tcf)
Tight Gas Sands	Characterization of the Speculative Areas of the Tight Gas Sands Formation	27.13	132,365	290-700	100-350
Devonian Shales	Characterization of the Speculative Areas of the Devonian Shales	27.13	150,000	200-900	80-450
Methane From Coal	Characterization of the Speculative Areas of Deep Coal Seams	27.13	38,000	200-500	20-250
Geopressured Aquifers	Characterization of the Speculative Areas of the Geopressured Aquifers	27.13	63,000	320-4800	10-500

3. Speculative Area

Square miles of speculative area in each resource type were estimated from a variety of sources including USGS resource data; Bureau of Mines data; and data from the University of Texas, DOE/Headquarters, MERC, and BERC/Las Vegas. This parameter presented another rough estimate of the size of the speculative portions of the unconventional resources and also served to focus the magnitude of the resource characterization efforts required.

4. Direct DOE Funding - 5-Year-Budget

This parameter represented the DOE funding requirement for the first 5 years of the Group II projects. The funding levels encompassed two major project components—base geology and a drilling program. Base geology costs encompass the collection of basic geologic data in the speculative areas. Among others, activities include well log studies, mapping, and outcrop sampling. The drilling program costs primarily encompass resource characterization drilling, principally core collection. The cost estimate for the drilling component only includes activities which will be performed within the 5-year time frame of the overall program. A more comprehensive and aggressive resource characterization effort, which would significantly increase the total portion of the speculative resources addressed, would encompass drilling activity extending over an 8- to 10-year time frame at a moderately higher level of total funding than the 5-year budget requirement.

* * * * *

Chapter IV presents the important features of the next step in the strategic analysis—establishment of priorities among the 21 candidate EGR projects.

DRAFT

IV. ESTABLISHMENT OF CANDIDATE PROJECT PRIORITIES

1. INTRODUCTION

Establishment of priorities among the 21 candidate programs (as depicted in Exhibit 10 of the Executive Summary) was the next major step of the strategic analysis. The objective of this prioritization was to provide EGR program managers with specific insights concerning the potential impacts of constrained budget levels on the timing, composition, and amount of benefits associated with the recommended EGR program.

In accomplishing this objective, two steps were employed:

- Performance of an analytical survey to establish priorities among Group I projects
- Conduct of in-depth interviews to determine priorities among Group II projects and also between Group I and Group II projects as a whole.

Both the analytical survey and personal interviews were addressed to a select group of 11 key DOE/ET decisionmakers who were responsible for planning and implementing the EGR R&D program.

2. FORMULATION AND RESULTS OF THE ANALYTICAL SURVEY

The analytical survey was constructed to provide insights as to the preferences of the key DOE/ET managers among the Group I projects and to obtain specific recommendations as to how trade-offs among the various project benefits, costs, and impacts should be made.

The survey participants (11 key DOE/ET decisionmakers) were given a list of the Group I projects (unidentified by name) and the estimates for the key performance parameters (see Exhibit III-7). Based upon the information presented, the decisionmakers ranked and scored each of the candidate Group I projects.[1]

---

1 Appendix H contains the analytical survey form and set of instructions which were given to each of the 11 key DOE/ET participants.

DRAFT

Once the surveys were completed, a detailed statistical analysis was performed.[1] The analysis revealed that the Group I projects fell into five priority groupings (see Exhibit IV-1). The analysis identified two important methodological findings, as follows:

- Priorities among these Group I projects could statistically be determined only on the basis of groups of projects (Category I implies highest priority and Category V implies lowest priority).
- Within each grouping, the projects were equal in terms of priority.

As depicted in Exhibit IV-2, the three performance parameters which were used most frequently by the survey participants as the single most important factor in establishing Group I project priorities included:

- Incremental annual production of gas in 1985 at a price of $3.00 per MCF
- Incremental annual production of gas in 1985 at a price of $1.75 per MCF
- Incremental ultimate recovery of gas at a price of $3.00 per MCF.

In addition, Exhibit IV-3 shows that the following two performance parameters were among the top three most frequently used by survey participants to prioritize the Group I projects:

- 5-Year DOE budget required for each project, and
- Incremental ultimate recovery of gas at a price of $3.00 per MCF.

The results of the statistical analysis of the Group I analytical survey then served as a major input to the second step of the analytical methodology.

---

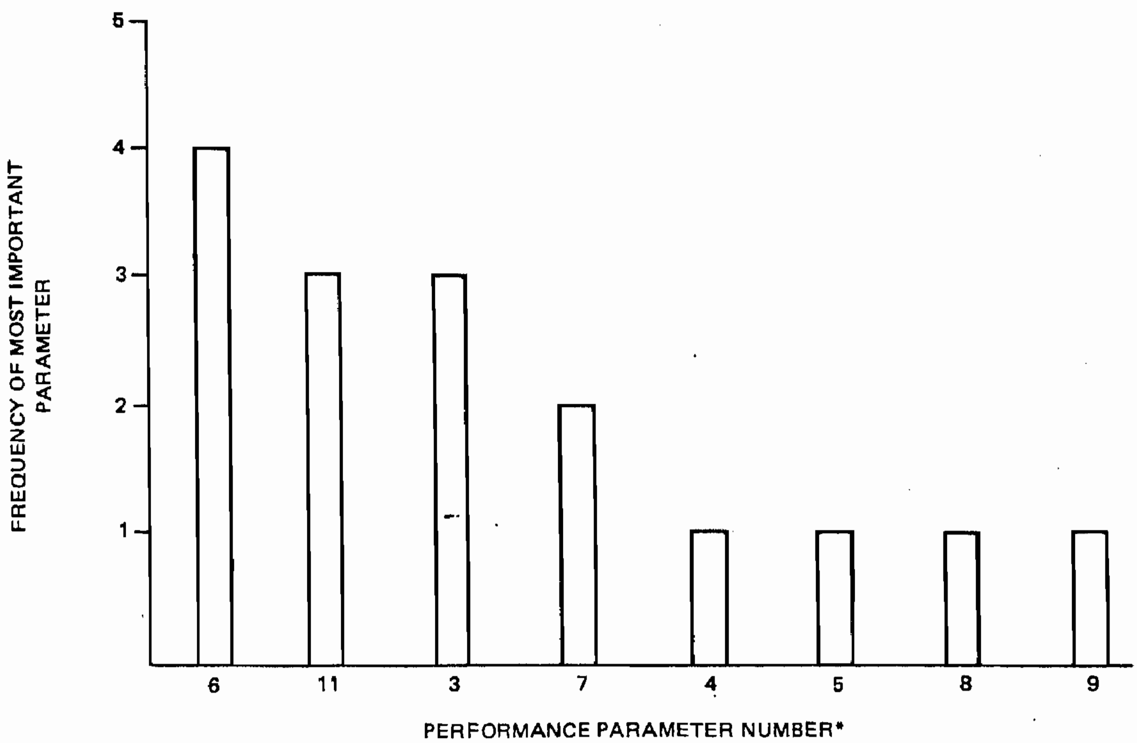
1 Appendix I presents the details of the statistical analysis of the analytical survey results. The major results of that analysis are presented here in the text.

DRAFT

EXHIBIT IV-1
Priority Categories for Group I Project

Priority Categories	Number	Resource Area	Name
I	3	Tight Gas Sands	Tight, Blanket Gas Formations
II	9	Tight Gas Sands	Greater Green River Basin, Full Program
	15	Tight Gas Sands	Other Tight, Lenticular Sands
	17	Tight Gas Sands	Uinta Basin, Full Program
III	10	Tight Gas Sands	Piceance Basin, Full Program
	6	Tight Gas Sands	Other Low-Permeability Reservoirs
	14	Tight Gas Sands	Shallow, Near Conventional Gas Sands
	7	Tight Gas Sands	Tight, Shallow Gas Sands
IV	8	Devonian Shale	Dual-Completion of Marginal Devonian Shales-Ohio
	11	Methane from Coal	Methane From Unminable Coal
	12	Devonian Shale	Deep Appalachian Front Area
	18	Devonian Shale	Other Devonian Shale Basins
	5	Geopressured Aquifers	Geopressured Aquifers, Full Program
	1	Tight Gas Sands	Low-Permeability, Shallow Gas Sands
	2	Methane from Coal	Methane From Minable Coal-Appalachian Basins
	16	Devonian Shale	Improve Recovery Efficiency in Productive Devonian Shales
V	13	Devonian Shale	Define Potential of Deep Devonian Shales

EXHIBIT IV-2
Frequency of Single Most Important Performance
Parameter Used in Ranking Group I Projects



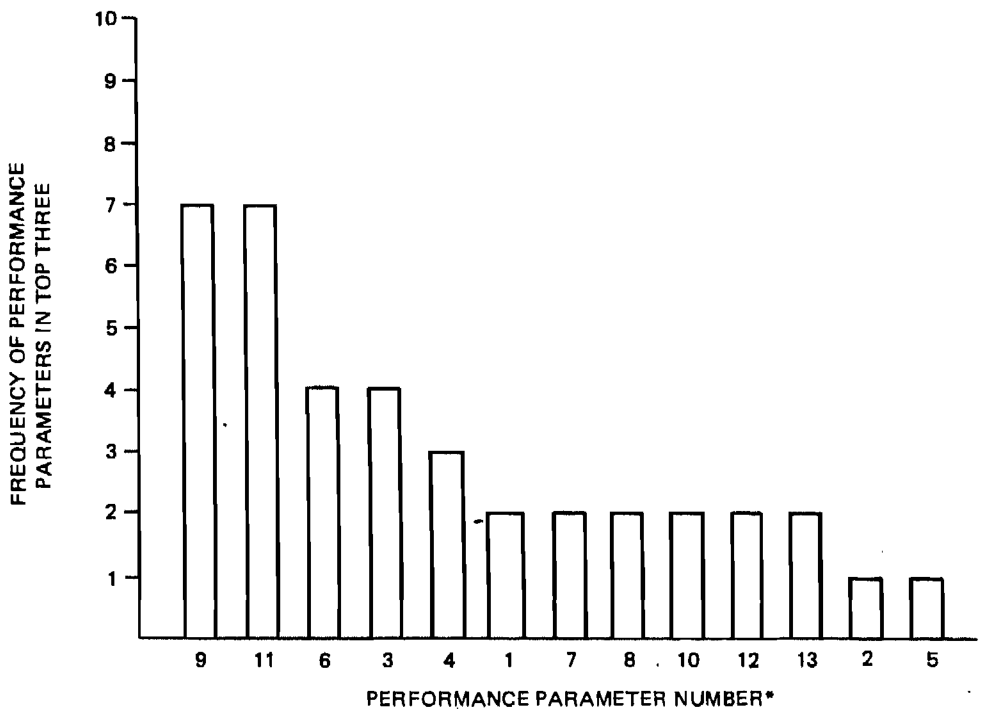
Legend*

1. Environmental Impact
2. Socioeconomic Impact
3. Incremental Annual Production (Tcf) 1985 @ $1.75/Mcf
4. Incremental Annual Production (Tcf) 1990 @ $1.75/Mcf
5. Incremental Annual Production (Tcf) 1995 @ $1.75/Mcf
6. Incremental Annual Production (Tcf) 1985 @ $3.00/Mcf
7. Incremental Annual Production (Tcf) 1990 @ $3.00/Mcf
8. Incremental Annual Production (Tcf) 1995 @ $3.00/Mcf
9. DOE Funding - 5 Year Budget
10. Incremental Ultimate Recovery (Tcf) @ $1.75/Mcf
11. Incremental Ultimate Recovery (Tcf) @ $3.00/Mcf
12. Incremental Ultimate Recovery (Tcf) @ $4.50/Mcf
13. Industrial Base Case Cumulative Production by 1990 @ $1.75/Mcf

Note: In two cases where participants employed ratios to derive their project evaluation parameters, each of the ratio components was counted in the determination of the frequency of parameter used.

DRAFT

EXHIBIT IV-3
Performance Parameters Most Frequently
Among the Top Three Used to Rank Group I Projects



* LEGEND

1. Environmental Impact
2. Socioeconomic Impact
3. Incremental Annual Production (Tcf) 1985 @ $1.75/Mcf
4. Incremental Annual Production (Tcf) 1990 @ $1.75/Mcf
5. Incremental Annual Production (Tcf) 1995 @ $1.75/Mcf
6. Incremental Annual Production (Tcf) 1985 @ $3.00/Mcf
7. Incremental Annual Production (Tcf) 1990 @ $3.00/Mcf
8. Incremental Annual Production (Tcf) 1995 @ $3.00/Mcf
9. DOE Funding - 5 Year Budget
10. Incremental Ultimate Recovery (Tcf) @ $1.75/Mcf
11. Incremental Ultimate Recovery (Tcf) @ $3.00/Mcf
12. Incremental Ultimate Recovery (Tcf) @ $4.50/Mcf
13. Industrial Base Case Cumulative Production by 1990 @ $1.75/Mcf

Note: In two cases where participants employed ratios to derive their project evaluation parameters, each of the ratio components was counted in the determination of the frequency of parameter used.

DRAFT

3. FORMULATION AND RESULTS OF INTERVIEWS

A set of structured interviews was constructed to provide insights as to the preferences of the 11 key DOE/ET decisionmakers between Group I and Group II projects and among the Group II projects.[1] In the interviews, the decisionmakers provided specific recommendations as to how trade-offs (at alternate budget levels) between the two groups of projects and among the Group II projects should be made.[2]

Prior to the interviews, the participants were supplied with the following data:

- Results of the Group I project prioritization
- Description of each of the four Group II projects (identified by resource base)
- Estimates of gas-in-place, technically recoverable gas, speculative acreage, and budget
- Discussion of the differences between Group I and II projects.

Based on this previously supplied information, the participants were then asked to first allocate five specific 5-year budget levels ($100, $200, $300, $400, and $500 million) between Groups I and II, and second to allocate five specific budget levels ($25, $50, $100, $150, and $200 million) among the four Group II projects.

The detailed statistical analysis of the interview results indicated a strong preference by the decisionmakers for Group I projects over Group II projects at all five budget levels.3 The proportion of total budget allocated to Group I projects varied insignificantly (77.3 to 77.9 percent)

---

1 Appendix J contains a thorough description of the process and forms utilized to conduct the personal interviews.

2 Nine of the eleven decisionmakers interviewed provided specific quantitative data concerning their trade-offs at alternate budget levels.

3 Appendix I contains the details of the statistical analysis. The major results are presented here in the text.

DRAFT

over the five budget levels (see Exhibit IV-4). The estimated production and recovery benefits associated with the five budget levels are illustrated in Exhibit IV-5. These figures were derived by mechanically applying the Group I budget allocations (indicated by the DOE/ET decisionmakers and previously presented in Exhibit IV-4) to the Group I projects in descending order of project priority until the budget allocation was exhausted.

In addition, a detailed analysis of the interview results pertaining to the allocation of Group II funding (at each of the five budget levels) among the four unconventional resources indicated the lack of any consistent pattern.

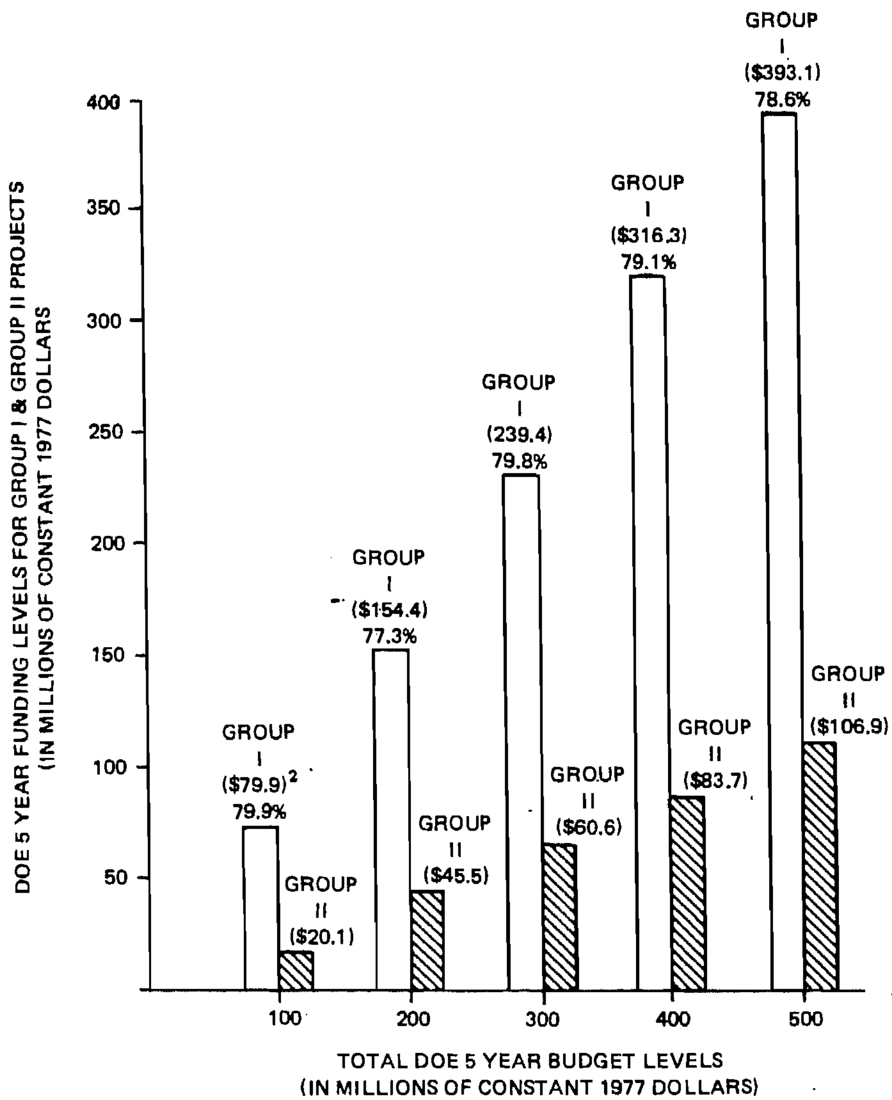
At each budget level, the allocations among the four resource areas were statistically indistinguishable. Thus, for example, at the $300 million budget level, the allocation of the Group II component ($60.6 million) was on the average divided equally among the Devonian shale, tight gas sand, geopressured aquifers, and methane from coal seams projects. This result occurred because of the wide divergence of opinion among the DOE decisionmakers concerning allocations among Group II projects. The potential benefits by resource area of these Group II budget allocations, as measured in terms of percentage of speculative resources characterized, are presented in Exhibit IV-6.

*   *   *   *

As depicted in Exhibit 10 of the Executive Summary, the last step in the strategic analysis consisted of final program selection. Chapter V presents the detailed results and important highlights of this step.

DRAFT

EXHIBIT IV-4
Average Total Dollar Allocation to
Group I and Group II Projects[1]

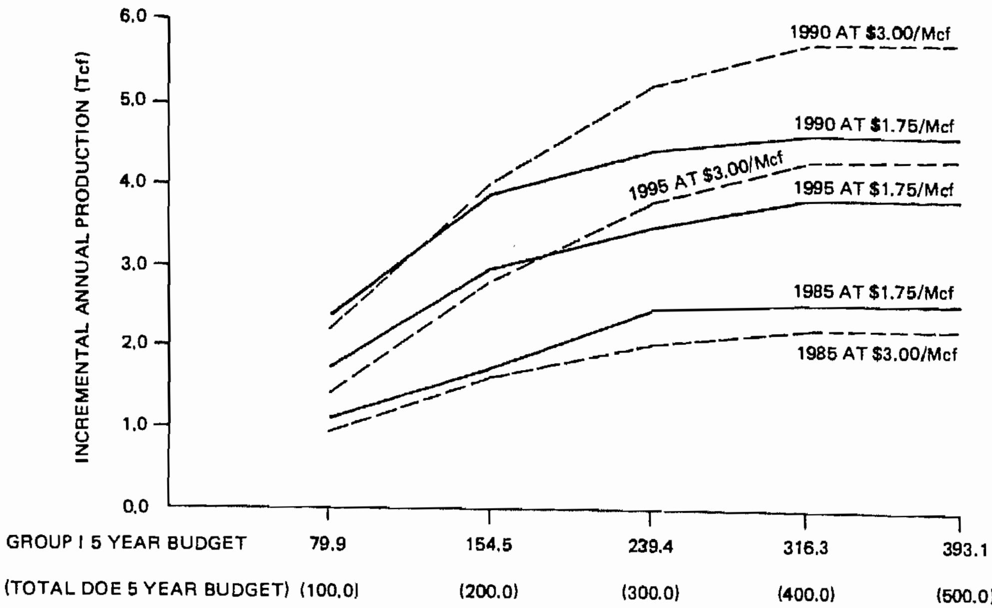


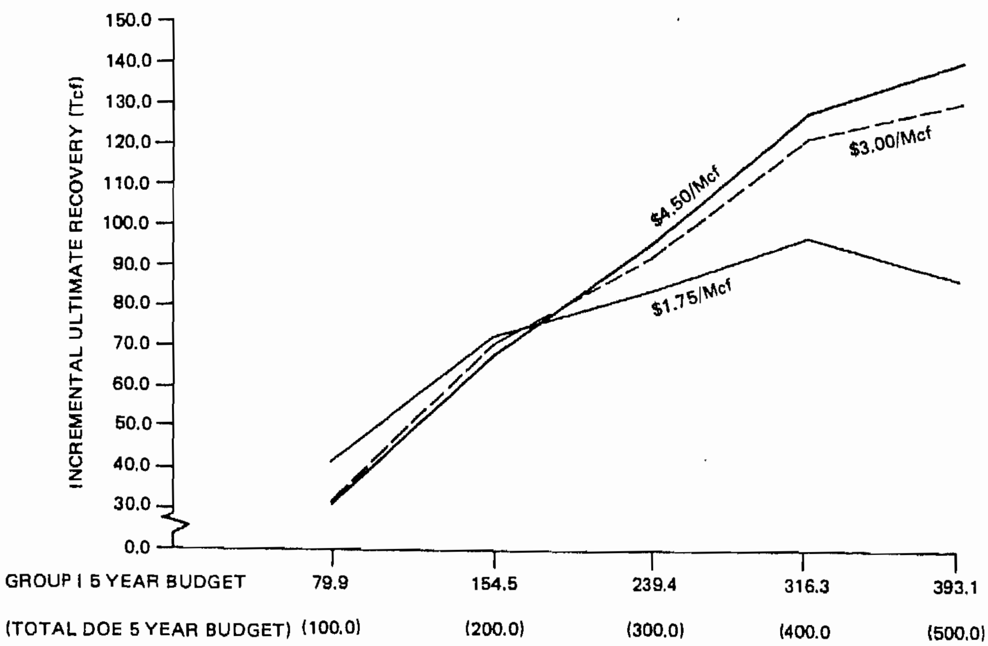
[1]The budget allocations between Group I and Group II projects displayed in this Exhibit represent the averages derived from the interviews conducted with 11 key DOE/Energy Technology managers responsible for the planning and management of the EGR program.

[2]Represents the proportion of total DOE 5-year budget allocated to Group I projects.

DRAFT

EXHIBIT IV-5
Incremental Annual Production of Group I
Projects at Alternative 5-Year Budget Levels

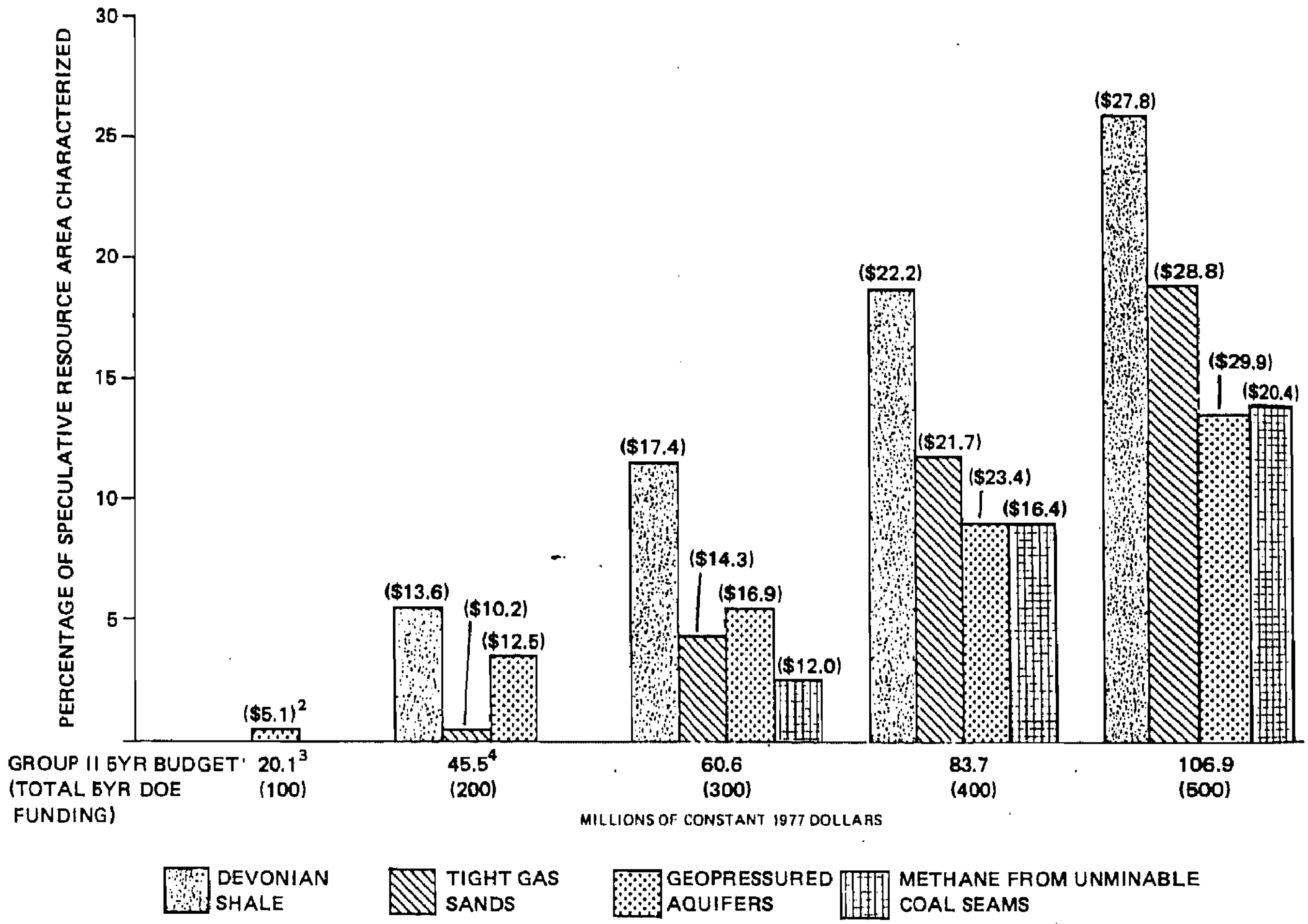




[1]The production and recovery estimates for each budget level were derived by mechanically applying the Group I funding allocations to the 17 Group I projects (Exhibit 1-2) in descending order of priority. The actual recommended program at any of these five budget levels will depend, of course, upon a set of key qualitative and programmatic factors which have not yet been explicitly considered in the strategic analysis.

DRAFT

EXHIBIT IV-6
Percentage of Speculative Resource Characterized for the Five Budget Levels of Group II Projects[1]



[1] The Group II project for each nonconventional resource area consists of two components: basic geologic studies and drilling. The basic geologic component for each project represents a fixed cost which must be funded before any drilling can be initiated. The funding requirements (basic geologic component) are: $10 million each for tight gas sands, Devonian shale, and coal seams; $5 million for geopressured aquifers.

[2] The numbers in parentheses are the average dollars (in millions) allocated to each Group II project by resource area.

[3] A total of $14.7 million of the $20.1 million was allocated, on average, to basic geologic studies in the Devonian shales, tight gas sands, and methane from coal seams. Only in the case of the geopressured resource was the allocation sufficient to cover the fixed cost for basic geological studies and also provide funding for drilling.

[4] This total includes $9.2 million for basic geologic studies in the methane from coal seams area.

DRAFT

V. FINAL PROGRAM SELECTION

1. INTRODUCTION

The objective of the final phase of the strategic plan was to refine the 21 high-potential Group I and Group II projects into a final 5-year DOE EGR R&D program. Three steps are involved in this refinement process as follows:

- Conduct trade-off analysis to assess the ability of the set of high-potential R&D projects, higher gas prices, and a combination of R&D and higher gas prices to significantly increase gas production from unconventional sources.
- Perform a profile analysis (by comparing the tentative recommended program with current DOE EGR program) to identify and review indicated new program thrusts.
- Incorporate key qualitative and programmatic factors which were not explicitly included in the analysis and prioritization of the set of 21 high-potential R&D projects.

2. TRADE-OFF ANALYSIS

The trade-off analysis took into consideration the relative merits of the proposed EGR R&D program versus non-R&D incentives and R&D in other related energy areas.

Numerous non-R&D incentives, such as the following, could have an effect on the rate of unconventional resource development:

- Increase prices to a level which is high enough to bring on a new threshold of resources
- Promote deregulation of gas in general or of specific gas resource areas to promote development of unconventional resources

DRAFT

- Provide limited tax incentives, such as depletion allowances and higher investment tax credits, to industry for developing unconventional gas resourc

- Implement loan guarantees for the commercial development of unconventional gas resources.

Since technical problems associated with unconventiona recovery represent a significant barrier to the rapid development of these resources, the above incentives are viewed to a large extent as having only a limited effect on accelerating the recovery of EGR resources in the short term. For the unconventional gas sources, higher prices (or other improvements in economic incentives) can substitute for improved technology but only up to a limit. Using economic incentives alone, however, appears to provide less than the optimum public policy choice. An advanced technology strategy (Advanced Case), at either \$1.75 per Mcf or \$3.00 per Mcf, is the preferred choice. As indicated in th following table, the Advanced Case provides substantially more gas than the current Base Case at all examined gas prices.

Price/Mcf	Base Case Ultimate Recovery (Tcf)	Base Case 1990 Production Rate (Tcf/Year)	Advanced Case Ultimate Recovery (Tcf)	Advanced Case 1990 Production Rate (Tcf/Year)
\$1.75	70	2.3	155-170	6.6
\$3.00	110	3.5	200-260	8.3
\$4.50	120	3.8	210-240	8.5

An advanced technology strategy in combination with a gas price of up to \$3.00 per Mcf offers a large amount of gas at a relatively low cost to the public. Under the Base Case, 3.5 Tcf per year would be produced in 1990. Ultimate recovery would be 110 Tcf, with 22 Tcf produced by 1990. Under the Advanced Case, the production rate from unconventional sources could reach 8 Tcf per year in 1990. Ultimate recovery would be 200 to 220 Tcf; with nearly 50 Tcf being produced by 1990. The energy cost to the public would be \$600 to \$660 billion ultimately.

DRAFT

Obtaining comparable quantities of gas from other sources would impose a higher energy cost on the public and place additional pressure on the balance of payments. Even assuming comparable quantities could be obtained at $4.00 to $5.00 per Mcf,[1] the energy cost to the public would be $800 to $1,100 billion ultimately, with significant portions being paid to other governments, at least in the initial year. These findings are shown on the following table.

Economic Considerations	Additions to Domestic Gas Supply (Tcf) By 1990	Ultimate	Energy Cost to the Public (Billions) By 1990	Ultimate
Advanced Case Enhanced Gas Recovery (at $3.00 per Mcf)	50	200-260	150.4	600-780
Substitute Energy Case (at $4.00 to $5.00 per Mcf)	50	210-240	200-250	840-1200

The Advanced Case strategy is also more cost effective than using economic subsidies in excess of real market prices. The analysis in the preceding section was bounded by market-level prices for natural gas of up to $3.00 per Mcf. However, as in the case of imported liquefied natural gas (LNG), the Government could consider a price of $4.50, and thus a subsidy of up to $1.50 per Mcf,[2] to stimulate production from unconventional gas sources. The analysis

1 Assuming the cost of imported gas is at $2.50 to $3.00 per Mcf, Alaskan gas at $3.00 to $5.50 per Mcf (including transportation), liquefied natural gas (LNG) imports at $4.50 per Mcf, and coal gasification at $4.50 to $5.50 per Mcf. The analysis of supplies from conventional gas resources due to higher prices was beyond the scope of this strategic analysis.

2 Again, the price of gas (or its economic equivalent) is expressed in 1977 dollars and held constant for the period of analysis; a $4.50 price in 1977, held constant with respect to 6 percent inflation, would be $7.20 in 1985 dollars and the $1.50 subsidy would be $2.40.

under the Base Case shows only very limited price elasticity between $3.00 to $4.50 per Mcf—total supply increases by 10 Tcf, from 110 to 120 Tcf—and at a high cost to the public. In addition, the analysis of the Base Case is based on empirical evidence and projections that have been built on evolutionary changes in gas prices up to about $3.00 per Mcf. At higher gas prices (particularly if they are guaranteed or subsidized), it is likely that industry will increase its near-term investment in R&D, and thus accelerate the production of the unconventional sources. In this case, one can defer public investment in R&D. In return, however, this will impose a considerable cost (from $180 to $360 billion) to the public. At these prices, gas recovery could range from 120 to 240 Tcf, depending on how industry's R&D initiatives respond to the price incentives.

Stimulating a $0.4 billion investment in R&D to attain 200 to 220 Tcf (assuming a market price of $3.00 per Mcf) is more cost effective and certain than spending $180 to $360 billion in public subsidies to obtain 120 to 240 Tcf (assuming a subsidy of $1.50 per Mcf over the same market price of $3.00 per Mcf). These findings are shown in the following table.

Economic Considerations	Ultimate Recovery (Tcf)	Additional Cost to the Public (Billions)
R&D with a $3.00/Mcf Market Price	200-220	0.4[1]
Public Economic Subsidy of $1.50/Mcf Over a $3.00/Mcf Market Price	120-240	180-360

1 Constant 1977 dollars

DRAFT

3. RECOMMENDED 5-YEAR EGR R&D PROGRAM

Exhibit V-1 presents the recommended, unconstrained 5-year DOE EGR R&D program. Implementation of the full program requires $596.9 million. This program consists of three major components:

- Group I projects
- Group II projects
- Environmental and Support Activities.

The Group I projects consist of the application of improved technology to the possible and probable areas of the unconventional resources. The majority of the 17 Group I projects entail cost-sharing with the private sector. The total DOE cost to implement these projects is $434.1 million over a 5-year period. The corresponding industry costs total $135.9 million. The four Group II projects entail the engineering-geologic characterization of the speculative portions of the unconventional resources. The primary objective of these projects is to obtain the necessary engineering and geologic data to realistically assess the economic recovery potential of such speculative areas. The Group II projects require $108.52 million to implement, and entail 100-percent funding by DOE.

The environmental and support activities require $54.3 million over a 5-year period and generally fall into the following four areas:

- Environmental studies and mandated program documents (e.g., Environmental Development Plan)

- Technology transfer[1]

---

1 Each of the individual Group I projects already contains specific technology transfer activities. The technology transfer activities specified here under the heading of "Environmental and Support Activities," relate specifically to DOE Headquarters functions and planning.

DRAFT

EXHIBIT V-1
Department of Energy Comprehensive Research and Development, Enhanced Gas Recovery Program

GROUP I PROJECTS

Resource Area	Name	DOE Funding 5 Year Budget (Millions of Constant 1977 $)	DOE Annual Funding (Millions of Constant 1977 $)					Incremental Ultimate Recovery (Tcf@$3/Mcf)	Incremental Annual Production (Tcf in 1985)		Incremental Annual Production (Tcf in 1990)		Incremental Annual Production (Tcf in 1995)	
			Year 1	Year 2	Year 3	Year 4	Year 5		$1.75/Mcf	$3.00/Mcf	$1.75/Mcf	$3.00/Mcf	$1.75/Mcf	$3.00/Mcf
Tight Gas Sands	Tight, Blanket Gas Formations	25.0	5.5	5.5	5.5	5.5	3.0	15.2	0.6	0.4	1.5	1.2	1.2	0.8
Tight Gas Sands	Greater Green River Basin, Full Program	44.7	7.6	9.0	9.0	9.0	10.1	16.7	0.4	0.4	0.8	0.9	0.6	0.7
Tight Gas Sands	Other Tight, Lenticular Sands	17.8	3.4	4.1	4.1	4.1	2.1	8.9	0.1	0.05	0.4	0.2	0.6	0.3
Tight Gas Sands	Uinta Basin, Full Program	44.8	7.6	9.0	9.0	9.0	10.2	15.5	0.5	0.5	0.8	1.0	0.5	0.6
Tight Gas Sands	Piceance Basin, Full Program	29.8	5.0	6.0	6.0	6.0	6.8	8.6	0.1	0.2	0.2	0.5	0.2	0.3
Tight Gas Sands	Other Low-Permeability Reservoirs	6.5	2.2	2.0	0.9	0.9	0.5	5.1	0.0	0.1	0.1	0.3	0.0	0.2
Tight Gas Sands	Shallow, Near Conventional Gas Sands	5.5	1.1	1.2	1.2	1.0	1.0	2.3	0.1	0.1	0.2	0.3	0.05	0.05
Tight Gas Sands	Tight, Shallow Gas Sands	9.3	2.0	2.0	2.0	1.7	1.6	7.6	0.0	0.05	0.0	0.1	0.0	0.2
Tight Gas Sands	Low Permeability, Shallow Gas Sands	6.2	1.3	1.4	1.4	1.1	1.0	1.3	0.0	0.0	0.0	0.0	0.2	0.2
Devonian Shale	Dual Completion of Marginal Devonian Shales, Ohio	29.3	5.9	7.0	6.4	5.3	4.7	6.0	0.1	0.1	0.2	0.3	0.1	0.3
Devonian Shale	Other Devonian Shale Basins	22.4	4.5	5.4	4.9	4.0	3.6	0.0-7.6	0.0-0.5	0.0-0.1	0.0-0.2	0.0-0.4	0.0-0.2	0.0-0.3
Devonian Shale	Deep Appalachian Front Area	6.5	1.5	1.8	1.5	1.0	0.7	0.0-4.5	0.0- 0.05	0.0-0.1	0.0-0.1	0.0-0.2	0.0-0.1	0.0-0.2
Devonian Shale	Improve Recovery Efficiency in Productive Devonian Shales	10.0	2.4	2.4	1.9	1.9	1.4	1.7	0.0	0.1	0.0	0.2	0.0	0.1
Devonian Shale	Define Potential of Deep Devonian Shales	25.1	5.8	7.0	5.3	4.0	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Methane From Coal	Methane From Minable Coal-Appalachian Basins	26.2	2.7	4.4	6.5	6.6	6.0	1.6	0.05	0.05	0.05	0.1	0.05	0.1
Methane From Coal	Methane From Unminable Coal-Western Basins	24.1	1.1	4.1	6.2	7.2	5.5	0.0-20.0	NA	NA	NA	NA	NA	NA
Geopressured Aquifers	Geopressured Aquifers, Full Program	100.9	23.3	25.6	23.3	16.1	12.6	1.0-28.0	NA	NA	NA	NA	NA	NA
	GROUP I TOTALS	434.1	87.9	97.9	95.6	84.4	73.3	91.5-150.6	1.90-2.50	1.90-2.25	4.25-4.55	5.1-5.7	3.5-3.8	3.85-4.35

GROUP II PROJECTS

Resource Area	Name	DOE Funding 5 Year Budget (Millions of Constant 1977 $)	DOE Annual Funding (Millions of Constant 1977 $)					Speculative Area (Square Miles)	Gas In Place (Tcf)	Technically Recoverable Gas (Tcf)
			Year 1	Year 2	Year 3	Year 4	Year 5			
Devonian Shales	Characterization of the Speculative Areas of the Devonian Shales	27.13	5.41	5.43	5.41	5.41	5.41	150,000	200-900	80-450
Tight Gas Sands	Characterization of the Speculative Areas of Tight Gas Sands Formation	27.13	5.41	5.41	5.43	5.43	5.41	132,365	290-700	100-350
Geopressured Aquifers	Characterization of the Speculative Areas of the Geopressured Aquifers	27.13	5.41	5.43	5.41	5.41	5.41	63,000	320-4800	10-500
Methane From Coal	Characterization of the Speculative Areas of Deep Coal Seams	27.13	5.43	5.41	5.41	5.41	5.41	38,000	200-500	20-250
	GROUP II TOTALS	108.52	21.7	21.7	21.7	21.7	21.7	670,365	1010-6900	210-1550

	DOE Funding 5 Year Budget (Millions of Constant 1977 $)	DOE Annual Funding (Millions of Constant 1977 $)				
		Year 1	Year 2	Year 3	Year 4	Year 5
Environmental and Support Services	54.3	10.8	10.8	10.8	10.8	10.8
EGR PROGRAM TOTALS	596.92	115.4	130.4	128.1	116.9	105.8

DRAFT

- Expansion of the knowledge base[1]
- General contractor support.

Exhibits V-2 and V-3 depict the target levels of production and ultimate recovery (at various gas prices). As delineated previously, these goals include an increase in ultimate recoverable gas of from 82 to 97 Tcf (at $1.75), and from 92 to 152 Tcf (at $3.00) above the Base Case. This represents an increase in annual gas production of 2 Tcf above the Base Case by 1985. It is important to emphasize several of the more prominent factors and assumptions upon which the program is based. These include the following:

- The methodology employed to develop the proposed program depends on the various estimates of major engineering, geologic, and economic variables which characterize specific unconventional resource areas and individual projects. Such estimates, while consistently derived, are subject to judgment and change as more is learned about the technical, economic, and institutional aspects of EGR. While widely divergent opinions and estimates concerning these major variables abound, the strategic analysis serving as the foundation for the recommended,unconstrained program took into consideration and utilized only those data which were fully supported by empirical evidence, historical precedent, and/or sound geologic-engineering theory. The recommended program contains a set of activities ("expanding the knowledge base") which focus on a detailed and continuous review, reevaluation, and additional investigation of the comprehensive analysis from which the recommended program was derived. As significant new insights are obtained, these will be incorporated into the EGR program strategy in the course of the anticipated regular reviews.

---

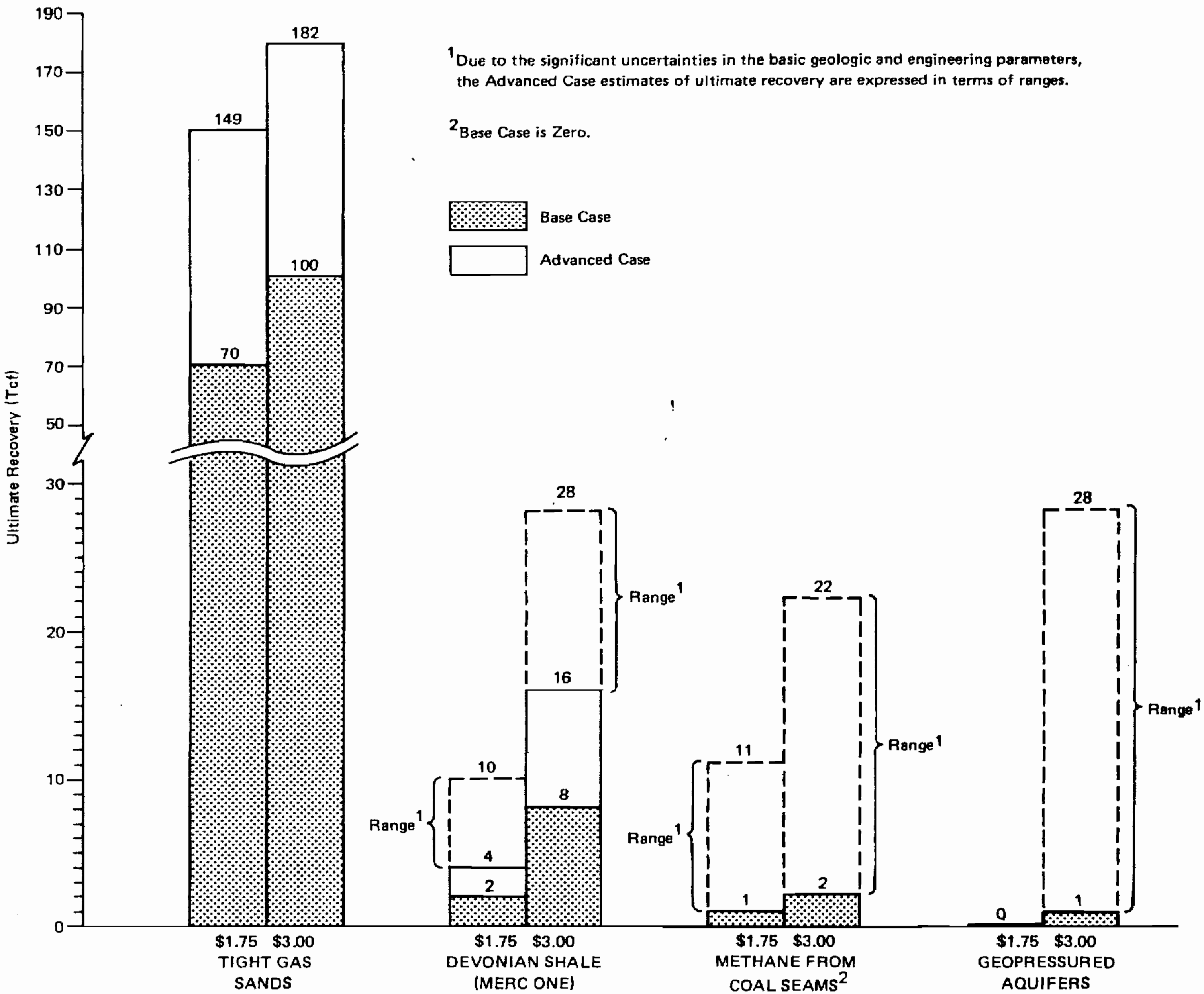
1 During the course of the strategic plan development, significant differences of opinion surfaced concerning the potential of certain unconventional resource areas and the ability of alternative technology approaches to economically unlock the resources. The technical uncertainties clearly demonstrated the need for continuing refinement, review, and further investigation in the development of the recommended program. Thus, the recommended 5-year program contains funding for these "knowledge base expansion" activities.

DRAFT

EXHIBIT V-2
Incremental Annual Production Levels for DOE EGR R&D Program

DRAFT

EXHIBIT V-3
Ultimate Recovery by Unconventional Resource Area
for DOE EGR R&D Program



[1] Due to the significant uncertainties in the basic geologic and engineering parameters, the Advanced Case estimates of ultimate recovery are expressed in terms of ranges.

[2] Base Case is Zero.

DRAFT

- The recommended program stresses a balance between near-term production goals and the need to assess more carefully the total economic potential of the speculative portions of the unconventional resources.

- The individual projects delineated in Exhibit V-1 represent broad classes of focused R&D activities. They are not, however, so finely defined as to be field or reservoir specific. The final definition of these projects will be the major focus of subsequent implementation planning.

- Major environmental and socioeconomic factors bearing on the rate of commercialization were explicitly considered in program development. These factors were incorporated into a set of aggregate indices which described their potential impacts on the development and commercialization of individual projects.[1] In-depth assessment of the environmental and socioeconomic impacts, realistic estimates of the costs to mitigate the more significant factors, and the development of the overall strategy for environmental and socioeconomic quality assurance are major elements of the subsequent implementation plan phase.

As depicted in Exhibit V-4, the recommended, unconstrained 5-year program contains R&D projects in each of the four major unconventional resources. DOE funding requirements and percentages are as follows:

- Tight Gas Sands - $216.7 million (36 percent of the total program)

- Devonian Shale - $120.4 million (20 percent of the total program

- Methane from Coal Seams - $77.4 million (13 percent of the total program)

- Geopressured Aquifers - $128.0 million (22 percent of the total program).

The remaining $54.3 million (9 percent of the total program) consists of the environmental and program support activities.

---

1 Refer to Appendix G for complete details on the environmental and socioeconomic factors.

DRAFT

DRAFT

EXHIBIT V-4
Present and Recommended Funding Levels for Unconventional Resource Areas ($-Millions)

	Tight Gas Sands							Devonian Shales							Methane From Coal						
	FY 1978	5-Year Fully Funded Program Year						FY 1978	5-Year Fully Funded Program Year						FY 1978	5-Year Fully Funded Program Year					
		1	2	3	4	5	Total		1	2	3	4	5	Total		1	2	3	4	5	Total
Budget Level	$5.0	41.1	45.5	44.5	43.7	41.7	$216.7	$12.0	25.5	29.0	25.9	21.6	18.3	$120.43	$6.8	9.2	13.9	18.1	19.2	16.9	$ 77.4
Percent of Total Annual EGR Budget[1]	11%	36%	34%	35%	37%	39%	(36%)	26%	22%	22%	20%	18%	17%	(20%)	14%	7%	11%	14%	16%	16%	(13%)

	Geopressured Aquifers							Engineering and Support Services						
	FY 1978	5-Year Fully Funded Program Year						FY 1978	5-Year Fully Funded Program Year					
		1	2	3	4	5	Total		1	2	3	4	5	Total
Budget Level	$19.0	28.7	31.0	28.7	21.5	18.0	$128.03	$3.8	10.8	10.8	10.8	10.8	10.8	$ 54.3
Percent of Total Annual EGR Budget[1]	41%	25%	24%	23%	19%	17%	(22%)	8%	9%	8%	8%	9%	10%	(9%)

[1] Number in brackets represents the percent of the total 5 year budget for all resource areas.

4. PROFILE ANALYSIS

The recommended, unconstrained program represents a significant increase in annual DOE EGR funding requirements ($119.3 million on the average versus $25.6 million for the current program in FY 78). As shown in Exhibit V-4, there are significant funding increases for each of the unconventional resource areas and engineering and support activities. The annualized costs for the tight gas sands represent an eightfold increase above the current level. For the other three unconventional resources, the annualized funding requirements associated with this program range from 35 percent (Geopressured Aquifers) to 100 percent (Devonian Shales) above FY 78 levels.

In terms of relative funding levels, this program represents a significant shift in emphasis toward the tight gas sands resource areas, which comprise 36 percent of the total funding requirements, as opposed to the 11-percent figure under the FY 78 budget. Devonian Shales, while significantly increased under this program in terms of annual funding levels, represent approximately 20 percent of the total program, as opposed to 26 percent under the FY 78 budget.

The relative shift in emphasis reflects the importance attached by key DOE managers to the significant near-term production potential associated with the tight gas sands. As indicated in Exhibit V-1, the incremental ultimate recovery for the tight gas sands, which could be unlocked by a combination of high gas prices ($3.00 per Mcf) and federally sponsored R&D, is significantly greater than the economic recovery potential for Devonian shales. Also, the program shows significant annual increases in funding for methane from coal and geopressured aquifers. These increases were not as large as those for the tight gas sands and Devonian shales, but still reflect the importance of a more accelerated effort to solve technology and resource characterization problems associated with methane drainage from coal seams and production from geopressured aquifers.

DRAFT

5. INCORPORATION OF KEY QUALITATIVE AND PROGRAMMATIC FACTORS

To make the transition from the recommended, unconstrained EGR program to a final EGR program, specific budget, qualitative, and programmatic factors must be incorporated into the analysis. Presently, the analysis is continuing to evaluate and incorporate the following factors.

- Historical and Anticipated Budget Levels. This unconstrained, recommended 5-year plan reflects but does not duplicate the DOE-funded R&D activities in certain areas in recent years. The recommended plan attempts to carry on significant work that has already begun and tends to emphasize those projects which have met with some success and deemphasize those which were not effective. Budget levels designed for technology and resource type must be implemented to reflect these concerns. Since this recommended 5-year program was constructed on an unconstrained basis, development of a final program will have to conform to real budget limitations.

- Program Diversification Requirements. The DOE/ET mission includes development of a variety of technologies and resource types in EGR. This mission requires that the greatest emphasis be placed on the most promising resources. It also calls for significant R&D in marginal areas as well. This emphasis is, to a great extent, already reflected in the wide range of projects which are included in the candidate set of 21 projects.

- Time and Risk Preferences. The emphasis on certain resource types is determined by DOE's concern for improving the gas supply situation in the near-term. Thus, those technologies and resources which are closest to commercialization in terms of industry risk preference are the ones which must be given highest priority in the final 5-year plan. This is currently reflected in the higher priorities given to tight gas sands and Devonian shales.

DRAFT

- Regional Market Considerations. Regional markets, pipeline infrastructures, and recent gas curtailments, have all influenced the development of unconventional resources in certain areas. A final 5-year plan must reflect R&D activities in areas where industry sees the development of unconventional resources as a solution to local/regional gas supply problems.

- Program Phasing Requirements. Since individual programs in the recommended 5-year plan will require very large volumes of start-up funding, it is unreasonable to assume that funds already allocated to EGR for FY 79 would be adequate. Thus, funding levels in the 5-year plan reflect budget needs for FY 80 to FY 84. This budgetary program phasing problem must be reflected in the final EGR program. Suggested annual budget levels will promote the complete and phased development of each project.

- Knowledge Base Activities. Other types of activities are necessary to augment and/or assess the effectiveness of the DOE EGR program. These include numerous energy research laboratory projects, research efforts by several universities, and contractor support in several areas, including simulation modeling, economic analyses, technology cost/benefit analyses, market studies, and other types of studies. In addition, considerable work is necessary to assess and develop management plans for environmental problems associated with EGR development. These knowledge base activities will have to be adequately accounted for and funded in the 5-year plan.

6. STRATEGY IMPLEMENTATION

Implementation of the final 5-year program will be guided by a subsequent Technology Implementation Plan (TIP). The TIP will set forth in greater detail the specific project activities and time phasing required to implement the program strategy. Projected completion of the TIP is scheduled for December, 1978.