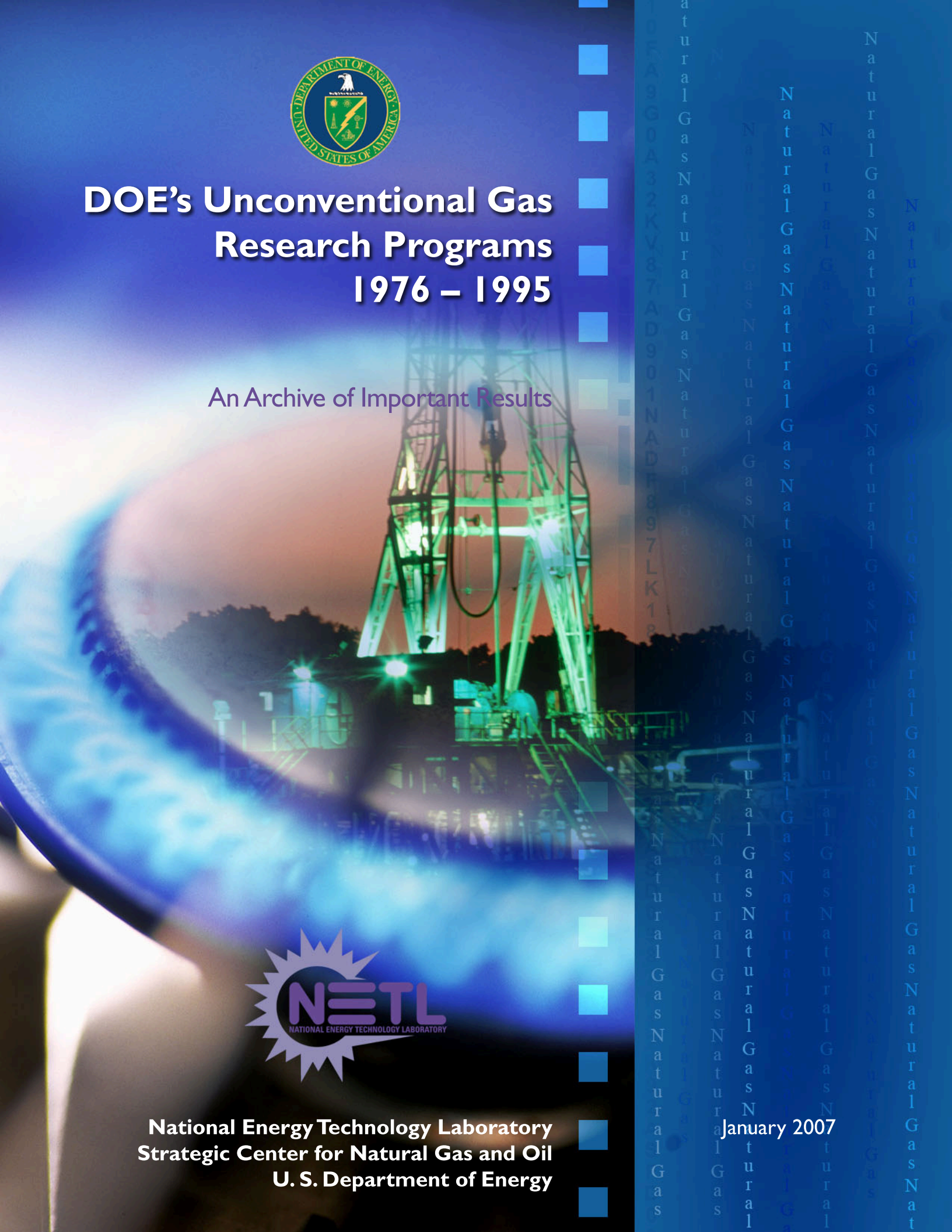
DOE's Unconventional Gas Research Programs 1976 – 1995

An Archive of Important Results



National Energy Technology Laboratory
Strategic Center for Natural Gas and Oil
U. S. Department of Energy

January 2007

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January 31, 2007

TABLE OF CONTENTS

Executive Summary 1
1. Background 11
2. GRI Research into Unconventional Gas Resources 14
3. Structure of the Enhanced Gas Recovery Program (EGR) 16
3.1. Eastern Gas Shales Program (1976-1992) 16
3.1.1. Key Questions and Related R&D Goals 19
3.1.2. Program Design and Overview of Major Projects 20
3.1.3. Key Eastern Gas Shales Projects 22
3.1.4. Highlights of Important Results 30
3.1.5. Subsequent Developments in DOE and Other Research Related to Eastern Gas Shales 35
3.2. Western Gas Sands Program (1978-1992) 49
3.2.1. Key Questions and Related R&D Goals 50
3.2.2. Program Design and Overview of Major Projects 53
3.2.3. Key Western Gas Sands Projects 60
3.2.4. Highlights of Important Results 64
3.2.5. Subsequent Developments in DOE Research Related to Tight Gas Sands 70
3.3. Methane Recovery from Coalbeds Program (1978-1982) 78
3.3.1. Key Questions Related to Coal Seam Methane 79
3.3.2. MRCP Program Design and Overview 80
3.3.3. Key Methane Recovery from Coalbeds Projects 84
3.3.4. Highlights of Important Results 91
3.3.5. Subsequent Research Related to Methane Recovery from Coalbeds 93
3.4. Deep Source Gas Project (1982-1992) 100
3.4.1. Key Deep Source Gas Projects 102
3.4.2. Highlights of Important Results 105
3.5. Methane Hydrates Program (1982-1992) 111
3.5.1. Methane Hydrates Workshop (March 1982) 111
3.5.2. Key Questions and Related R&D Goals 112
3.5.3. Program Design 115
3.5.4. Major Contracted Gas Hydrates Projects 117
3.5.5. Methane Hydrate Research Efforts of METC's In-House Organization 124
3.5.6. Highlights of Important Results 125
3.5.7. Subsequent Developments in Methane Hydrate Research 126
3.6. Secondary Gas Recovery (1987-1995) 133
3.6.1. Key Objectives and Program Design 134
3.6.2. Major Projects 137
3.6.3. Major Results 139
4. Elements of Spreadsheet Bibliographies (by Program) 142

Appendix A: Details of Major 1970-1980 Unconventional Gas Resource Assessments 144

DOE's Unconventional Gas Research Programs of 1976-1995
An Archive of Important Results

Executive Summary

Beginning about 1976, groundbreaking research directed by the Department of Energy catalyzed several innovative industry "firsts" that later became commercial technologies, and also resulted in the acquisition, analysis and wide dissemination of an enormous quantity of "ground truth" data on a topic that at the time generated little interest: unconventional sources of natural gas. At the time, less than 7 percent of the natural gas produced from gas wells came from unconventional sources.

Today, more than 40 percent of the natural gas produced from gas wells in the United States—7.5 trillion cubic feet (Tcf) per year—comes from unconventional sources: fractured gas shales, tight gas sands and coal seams. Without the contribution from these reservoirs, the volume of natural gas the nation must import would be much higher than its current level, which has reached about 15 percent of consumption.

The growth in unconventional gas production over the past thirty years has been driven by several factors, but the rapid growth in new technologies for finding and producing unconventional gas have played an important role. Tax credits that began in 1980, and higher natural gas prices driven by rapidly growing demand have played a part in supporting economics, but the tools for tapping into these resources when economics began to make sense would not have been there, or would not have been adapted as quickly, if the groundwork had not been laid by research carried out through the DOE's Unconventional Gas Research (UGR) Programs.

For example, the first use of nitrogen foam to effectively stimulate production of gas from shale wells, the discovery of how natural gas is stored in coal seams and fractured shales, recognition of the importance of interconnected natural fractures in the production of gas from such reservoirs, the first use of directional drilling in shale reservoirs to improve productivity by intersecting fractures, the creation of advanced tools and methods for measuring the properties of unconventional reservoir rocks, and the early development of micro-seismic monitoring techniques for mapping hydraulically-created fractures; are just a few of the advances initiated by DOE-funded research. The pay-offs from these early investments are reflected in the commercial technologies that are making the current expansion of unconventional gas production possible.

Today, for example, micro-seismic fracture mapping is playing a key role in optimizing the way gas wells are hydraulically stimulated in the Barnett Shale Play in North-Central Texas. The play has been proven to contain at least 2.1 Tcf of natural gas, and some industry experts believe it to be the largest onshore natural gas field in the United States. But the first systematic application of microseismic fracture mapping was a project funded by DOE and carried out by Los Alamos National Labs in the 1970s. Subsequent research performed at the DOE's Multiwell Experiment (MWX) site in Colorado during the 1980s helped refine the process. Although it took two decades to make this technology workable for normal oil and gas activities, DOE's long-term support was critical in the development of commercial tools for microseismic monitoring of fracturing procedures.

As well, many wells in the Barnett play are drilled horizontally to intersect fractures and maximize the flow rate of gas. DOE-industry collaborative efforts in the 1970s resulted in the first directionally-drilled wells designed to intersect fractures in the Appalachian Basin's Devonian shale play. These cost-shared demonstrations and the lessons learned from them set the stage for the technological advancements leading to what is today a widely applied practice in fractured shale plays like the Barnett and other reservoirs.

The largest portion of the unconventional gas produced today comes from the low permeability (tight) sandstone reservoirs of the Rocky Mountains. In the Rulison Field of the southern Piceance Basin of Colorado, carefully chosen well locations and technically advanced well completion designs are dramatically increasing the volumes of gas that can be extracted from these tight sands. However, the knowledge base and fundamental science behind these advanced practices are rooted in work carried out by DOE at its MWX Site in the Rulison Field during the 1980s. This research provided key insights that convinced industry new technologies could be economical. Many of the same lessons are now being applied in the tight sand reservoirs of Wyoming as well.

An estimate of the benefits resulting from DOE's unconventional gas research programs was prepared and reported on in the National Research Council report titled *"Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000"* published in 2001. The Council reported benefits of several billions of dollars in incremental state and federal tax revenues, trillions of cubic feet of incremental gas supply, and billions in consumer savings due to lower natural gas prices accompanying the supply increase.

Because of the substantial base of knowledge developed by DOE and the technologies catalyzed by this early research, the Energy Information Administration (EIA) is now able to make predictions of a strong future for unconventional gas production. Production from tight sands, gas shales and coal seams is expected to reach 10.2 Tcf by

2030, nearly nine times the volume being produced when DOE's research program was initiated.

Three major resource areas (Eastern Gas Shales, Western Gas Sands, and Coal Seams) and three less immediately accessible resources areas (Gas Hydrates, Deep Source Gas and Secondary Gas Recovery), were the targets of R&D programs that extended from about 1976 through 1992. The total amount of money spent on these programs—about $220 million, or less than $15 million per year—were a small fraction of the billions spent by DOE over that time period. Yet these investments provided a foundation for technology development that led to the technology products and E&P methodologies highlighted below.

- *Foam Fracture Technology* – The Eastern Gas Shales Program (EGSP) was responsible for the first use of nitrogen foam fracture technology. Prior to this time, shale wells had been explosively stimulated in open-hole well bores. Foam fracture stimulation technology allowed sand to be transported by the fracture fluid while simultaneously reducing the volume of water used. By 1979, foam fracturing was the preferred commercial method of stimulation for Devonian shale gas wells and commercial services were widely available to operators in the eastern United States.

- *Oriented Coring and Fractographic Analysis* – In 1977 the EGSP carried out the first oriented coring and fractographic analysis of Devonian shale to detect natural fractures. The use of oriented core was an innovation which allowed not only the detection and location of natural shale fractures, but also allowed for the determination of both fracture azimuth and dip - key parameters in determining geologic structural trends, gas production mechanisms, reservoir modeling parameters and reservoir anisotropy. The core analysis techniques developed for identifying natural and core-induced fractures have since been used throughout the US to evaluate low-permeability gas reservoirs.

- *Gas Shales Logging Suite* – As part of the EGSP, DOE worked with the well logging service industry to jointly develop an electric downhole well logging suite for air-drilled bore holes. Most previous logging had required water or mud-filled wellbores, liquids which damaged the permeability of the fluid-sensitive shales. By 1985, a commercially available well logging suite was being used by industry within the Appalachian Basin.

- *Role of Adsorption in Devonian Shale Production Mechanism* – Gas desorption data from 35 cored EGSP wells were used to establish the role of adsorbed gas and the mechanism for gas flow through a network of interconnected natural fractures. This permitted the development of more accurate production models that incorporated dual

porosity/dual permeability fluid flow in the reservoir, that in turn resulted in better tools for reserve estimates and economic decision-making by industry. These reservoir models also paved the way for later, similar models for coal seams.

- *Downhole Video* – The EGSP carried out the first use of a downhole video camera in the history of U.S. oilfield operations. By 1981, downhole video camera services had been commercialized in the eastern U.S. with multiple companies operating in Ohio, Kentucky and West Virginia.

- *Large-scale Massive Hydraulic Fracturing* – The EGSP introduced large-scale Massive Hydraulic Fracturing (MHF) to the Eastern gas shale marketplace. By 1990, commercialization of MHF stimulation allowed industry to recognize the benefits of such large scale stimulations in targeted shale areas.

- *Directional Drilling to Improve Productivity* – DOE-industry collaborative efforts resulted in the first Appalachian Basin high-angle gas shale directional well in 1975, with additional wells drilled between 1978 and 1990. The EGSP was responsible for the first air-drilled horizontal shale well, the first recovery of core from a horizontal, air-drilled shale well, the first successful use of external casing packers in a horizontal well, and the first horizontal well completed with seven individual hydraulically fractured intervals. These cost-shared demonstration wells were the first to identify the technology enhancements needed for wider application of underbalanced horizontal drilling in the United States, a practice that is now widely used to enhance production from other fractured shale reservoirs (e.g., Barnett shale of the Fort Worth Basin).

- *Electromagnetic Measurement-While-Drilling* – Wells drilled as part of the EGSP saw the first use of electromagnetic measurement while drilling (EM/MWD), where it was introduced as a method for steering downhole motors. More than 13 field tests were conducted during and after the EGSP program, leading to successful commercial application in the US and western Canada.

- *Carbon Dioxide Fracture Treatment* – The EGSP introduced the use of CO_2/Sand stimulation for Devonian shale wells, a technology not previously used in the US. CO_2/Sand stimulation subsequently became one of the stimulation options used in the San Juan Basin on a commercial basis.

- *Characterization of Eastern Shale Resources* – Basic knowledge gained from the collection of 38,000 feet of oriented core from more than 35 wells and the geochemical, fracture characterization, and detailed lithological analyses carried out on the core, was used to characterize the Eastern gas shale resource across the

Appalachian Basin, including stratigraphy, structure, and geochemistry. Estimates of recoverable gas in specific states were determined and published for use by operators. Studies were extended to include organic shales in the Illinois and Michigan Basins.

- *Economic Relationship of Technology and Recovery* – The EGSP performed the first integrated assessments, based on subsurface data and validated models, to show how the application of enhanced fracturing and infill drilling could be used to improve the economics of Eastern gas shale production. This approach re-defined how operators viewed Appalachian gas shale E&P.

- *Advanced Tight Gas Core Analysis Technology* – Specialized equipment and techniques were developed by the Western Gas Sands Program (WGSP) to fully characterize the reservoir properties of very low permeability rocks. Of particular importance were methods that were developed to test rocks under both *in situ* stress and water saturation conditions and capillary pressure measurements to aid in the understanding of the important two-phase flow mechanisms (water and gas). These techniques are now routinely used for low-permeability core testing and are available commercially.

- *Tight Sand Reservoir Characterization Methodology* – The WGSP utilized core samples in three closely spaced wells, along with the careful assessment of surface outcrops, to develop methods for quantifying the size of sandstone lenses in various depositional environments. This methodology, which is now used by numerous companies working in tight-sand basins, provides critical information needed for resource assessment, reserves calculations, fracture design, and well spacing in these fields.

- *Naturally Fractured Core Analysis* – Through the WGSP, DOE developed a process for analyzing fractured core and for identification of coring induced fractures that has been transferred to numerous companies and is routinely used by industry. Information from stress sensitivity testing of naturally fractured cores is now used in many reservoir and fracture models.

- *Stress Testing and Applications* – The Multiwell Experiment Site (MWX) employed by the WGSP was where a methodology for micro-fracture stress testing through perforations using down-hole shut-in was fully developed and where anelastic strain recovery and circumferential velocity anisotropy were validated. Micro-fracture stress testing is a testing procedure now used routinely by companies throughout the world and anelastic strain recovery is a commercial service available through Halliburton.

- *Advanced Tight Gas Log Analysis* – By running multiple logging suites (including experimental logs) and coupling the results with the results of core analysis, new correlations were developed that more accurately predicted tight gas sand reservoir properties. The data were made available to all of the commercial logging companies and used to improve the quality of tight sand formation evaluation.

- *Extreme Overbalanced Perforating* – While attempting to develop methods for effectively connecting to and testing the reservoir, the first extreme overbalanced perforation operations were conceived and performed at the MWX site. Extreme Overbalanced Perforating is a service performed by Halliburton and used routinely.

- *Deviated or Horizontal Drilling in Fractured Reservoirs* – The Slant Hole Completion Test carried out as part of the WGSP resulted in a number of recommendations for using deviated well bores to exploit fractured reservoirs. This approach is now widely applied throughout the U.S.

- *Micro-Seismic Monitoring and Fracture Mapping* – The first successful micro-seismic monitoring tests in tight gas reservoirs were conducted at MWX and showed that fractures grew out of zone proportional to the stress contrasts and that fracture lengths were considerably shorter than designed. The M-Site testing that followed on the heels of the MWX portion of the WGSP, validated the accuracy of down-hole micro-seismic monitoring for real-time mapping of hydraulic fracture growth and established the accuracy of the technique, the interpretation of the data, and the technology needed to acquire and process the data. Micro-seismic monitoring is now considered the most accurate method of imaging fracture growth and is now a globally-available commercial service. Downhole tiltmeters were first used for fracture monitoring during these tests and this technology is now a commercial service (Pinnacle Technologies) available to map fracture height and length.

- *Fracturing Mechanisms* – Important insights into the mechanisms of fracturing, developed from the early work at MWX and the follow-on work at M-Site, are now being used in fracture models. Some of these are the development of multi-stranded fracture systems as a routine part of fracturing, the identification of additional fracture height containment in highly layered reservoir systems, and the variability in fracture development with different fluid systems.

- *First In Situ Observation of Fracture Behavior* – WGSP experiments provided the first observational evidence of fracture behavior *in situ*. These tests showed that *in situ* stress contrasts were the primary feature controlling fracture height growth, that modulus contrasts had little effect on height growth, that natural fractures caused

considerable offsetting and branching of fractures, and that stress changes across faults and interfaces could stop fractures.

- *PDC Bit Technology Development* – Drilling technology was advanced by breakthroughs in polycrystalline diamond compact (PDC) bits through work done at Sandia National Labs and funded by DOE. The WGSP proved the effectiveness of the Stratapax core bit. PDC bits accounted for 60 percent of the footage drilled worldwide in 2005, and revenue from PDC bit sales reached $600 million in 2003.

- *Comprehensive Tight Gas Resource Assessments* – The WGSP provided the first comprehensive scientific quantification and characterization of a vast new resource, removing any question that pursuing the difficult technical challenges of enabling large-scale tight gas production was clearly worthwhile. The program highlighted the concept and importance of basin-center gas formations, providing a rationale for the unique off-structure exploration and development techniques that would enable production from overpressured, low-permeability reservoirs. As a result of this work, industry began not only to appreciate the volumes of gas present, but to see a way in which it could be produced. As a result, tight gas began to be widely recognized as a key part of the nation's resource base.

- *Comprehensive Coal Seam Gas Resource Assessments* – The Methane from Coal Seams Program (MCSP) established that a large, 400 Tcf natural gas resource was contained in coal seams across 16 priority basins. Basin reports were completed and published and gas-in-place estimates determined for eleven basins.

- *Mining-Related Insights* – The MCSP helped to characterize the shape of the gob area above longwall mining, assessed the effective placement of gob wells to maximize recovery of gas and assessed the overall potential for gas production associated with longwall mining in the Appalachian Basin. MCSP experiments verified that hydraulic fracturing for recovery of coal seam gas in advance of mining does not damage a mine roof and that predrainage of methane by drilling long, horizontal holes from within a mine is compatible with longwall mining operations.

- *Understanding Fracture Mechanisms in Coal Seams* – Significant research was conducted to better understand the mechanisms controlling fracture initiation and propagation, leading to the confirmation that: in the absence of confining stresses, fractures will propagate along bedding planes, and that natural shale layers (stringers) within the coal have a definite influence on fracture toughness.

- *Coal Seam Gas Production Technology Development* – MCSP efforts included the design, application and/or evaluation of 40 fracture treatments in six basins. These tests helped to demonstrate: that coal seam gas could be efficiently produced using vertical wells rather than in-mine horizontal drain holes, the technical feasibility of completing a well in multiple coal seams from a single wellbore, that economic production could be achieved from a multiple completion in spite of low methane content of individual seams, and that nitrogen-generated foam is suitable for stimulating coalbeds.

- *Fundamental Nature of Methane Storage and Flow in Coal* – DOE's initial coal seam methane R&D program provided a significant portion of the scientific knowledge base for this gas resource, and established the essential coal-bed methane storage and flow mechanisms, including adsorption, desorption, diffusion, and fracture-dominated flow.

- *Enhanced Production from Existing Gas Reservoirs* – The Secondary Gas Recovery Project identified 288 Tcf of natural gas in the nation's older fields that remained unrecovered due to geologic complexity. The program, a joint venture among government, industry and academia, applied 3-D seismic and vertical seismic profiling to developing these reserves and transferred the tools to industry.

- *Basic Gas Hydrates Knowledge* – DOE's Gas Hydrates R&D program developed the first framework of basic knowledge about the distribution and physical/chemical nature of naturally occurring methane hydrates, including comprehensive studies of 15 offshore basins and preliminary estimates of gas-in-place for hydrate deposits. This collaborative gas hydrates research effort among industry, national labs, academic institutions and multiple Federal agencies continues to the present day and is currently the leading force in international gas hydrate research.

- *Identified North Slope Hydrates* – The Gas Hydrates program established the existence of hydrates in the Kuparuk Field of the North Slope of Alaska. The current interagency gas hydrate R&D program is funding a joint venture stratigraphic test well in that same area with BP Exploration Alaska (BPXA) to test the program's seismic-based hydrate exploration methodology.

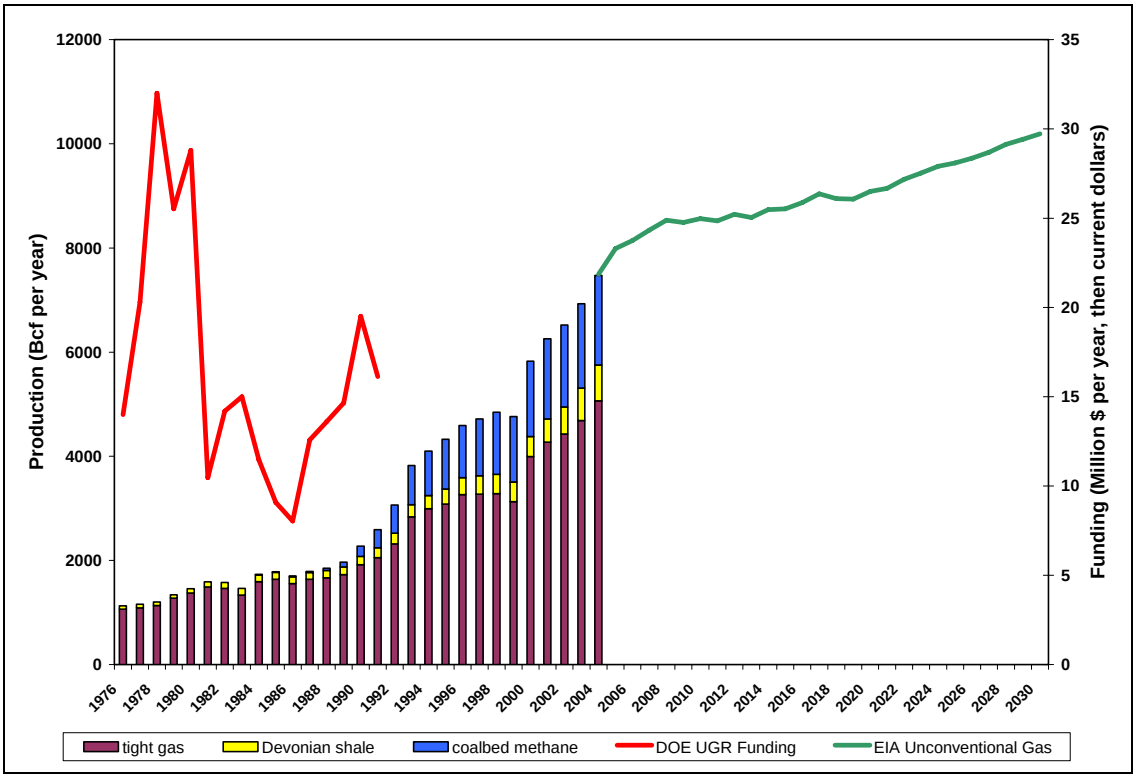
- *Early Gas Hydrate Production Models* – The Gas Hydrate Program developed the first preliminary production models for depressurization and thermal production of gas from hydrates, setting the stage for what is today a suite of models that are being used to model potential production scenarios in both arctic and marine hydrate settings.

An estimate of the benefits resulting from the DOE's unconventional gas research programs of the 1980s was prepared and reported on in the National Research Council report titled *"Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000"* published in 2001.

The estimated impacts resulting from the EGSP were an incremental 4.17 Tcf in gas supply, 7.83 Tcf in proven reserves and 10,600 wells drilled over the 1978-2020 time period. The dollar value of the benefits from state and federal tax revenue of the EGSP was calculated at $1,040 to $2,080 million using a conservative value of $0.25 to $0.50 per Mcf for the additional gas supplies. Using the total program cost of $92 million, the undiscounted benefit/cost ratio would be 10:1 to 20:1, based on incremental tax revenue alone. In addition, DOE estimated over $8 billion in consumer savings due to lower gas prices.

The same report determined that the Western Gas Sands program was successful in its goal of increasing the supply of natural gas at lower cost. Tight gas production from the Rocky Mountain gas basins was only 162 Bcf in 1978 at the start of the program; 10 years later it stood at 224 Bcf and in 2000 (when the NAS report was written) production was estimated at 700 Bcf, a fourfold increase. Since the report was written, Rocky Mountain tight sand gas production has grown even more; 2004 production from the five targeted basins was 1433 Bcf, nearly nine times the rate at the start of the WGS Program.

The NAS report conservatively calculated a benefit to cost ratio of 8.9, and a contribution of $591 million (1999 dollars) from royalties on federal lands and from increased state severance taxes due to displacement of imports. Because of the substantial base of knowledge and technologies developed under the WGS Program, the Energy Information Administration (EIA) has been able to make predictions of strong future tight gas production. The EIA calls for tight gas production from the Rocky Mountain basins to reach nearly 2,300 Bcf and overall tight gas production in the U.S. to reach nearly 5,500 Bcf in 2020.



Historical and Estimated Future Unconventional Gas Production, Relative to DOE Unconventional Gas R&D Funding 1978-1992.

The NAS report also determined the economic benefits from DOE's Methane from Coal Seams Program to total $499 million (1999 dollars) in increased revenues and cost savings to producers, primarily from the Warrior and San Juan basins. In addition, $91 million (1999 dollars) was credited from royalties on federal lands and from increased state severance taxes due to displacement of imports. If DOE's basic research were credited with only one-third of the benefits, recognizing the contributions of subsequent Gas Research Institute and industry efforts, this would amount to about $200 million, compared to a total investment of about $30 million.

The benefits attributable to the gas hydrates program are harder to quantify but still very significant. The early DOE program initiated the first scientific inquiry into the nature and distribution of gas hydrate to be focused on its potential use as a future source of energy. The level of international interest in gas hydrates has grown tremendously since then, and the United States' position as a leader in gas hydrate research can be traced back to this early program. Should methane from gas hydrates someday play the same important role in U.S. gas supply that unconventional gas does today, it will be due to the R&D investment begun during the 1980s and extended during the current program.

1. Background

In the mid-to-late 1970s, fears that supplies of natural gas would soon run out led to the initiation of U.S. government and private efforts to better understand both the magnitude of the nation's natural gas resource and how best to find and produce it. In particular, interest focused on natural gas resources in unconventional reservoirs: low permeability formations (also called *tight sands* or *tight gas*), Devonian shales, methane-rich coal seams, and geopressurized aquifers. This gas had not been included in previous estimates of the Nation's natural gas resource base, but the likelihood that higher gas prices and new technologies might make it economic to produce led to several seminal studies that in turn became the basis for a number of government and private R&D efforts.

The first study of unconventional gas resources was completed by the Federal Power Commission in 1973. It was followed by studies published over the following seven years by the National Academy of Science (NAS) the Federal Energy Regulatory Commission, Department of Energy (Lewin & Associates), and the National Petroleum Council (see Appendix A for details on these documents, listed below):

- U.S. Federal Power Commission, Task Force Report of the Supply-Technical Advisory Task Force-Natural Gas Technology, in *Natural Gas Survey*, Vol. 2, 1973.
- National Academy of Sciences, *Natural Gas from Unconventional Geologic Sources*, 1976, Energy Research and Development Administration Report FE-2271-1.
- Federal Energy Regulatory Commission, U.S. Department of Energy, *National Gas Survey: Non-conventional Natural Gas Resources*, DOE/FERC-0010, June 1978.
- V. A. Kuuskraa, et al. (Lewin & Associates, Inc.), *Enhanced Recovery of Unconventional Gas (Vols. I, II and III)*, October 1978, U.S. Department of Energy Publication HCP/T270S-01, 02, 03.
- National Petroleum Council, *Unconventional Gas Sources*, five volumes, 1980.

The NAS study consisted of a one-day forum of experts on the topic of unconventional gas in January 1976 in Washington, D.C. Their discussions, published later that year, determined that … *"It is evident that a large quantity of methane remains in the sedimentary rocks of this country … however, total resource figures are highly speculative and much work must be done to produce acceptable estimates. …The level of funding devoted to investigating new sources of methane has been miniscule, with the greater part of the work dependent upon private-sector funds and motivation. … Efforts to develop cheap, effective means for producing gas from these presently underdeveloped resources should be encouraged and imaginative ideas subsidized."*[1]

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[11] National Academy of Sciences, *Natural Gas from Unconventional Geologic Sources*, 1976, Energy Research and Development Administration Report FE-2271-1.

Seeking to maximize development of all domestic energy sources, Congress authorized funding for an Unconventional Gas Research Program in FY 1976. The original program consisted of three separate resource-specific sub-programs:

1. Eastern Gas Shales Project (EGSP) focused on Devonian-age organic shales of the eastern U.S.
2. Western Gas Sands Project (WGSP) focused on low permeability gas sandstone reservoirs of the western U.S.
3. Methane Recovery from Coalbeds Project (MRCP) focused on free methane associated with both mineable and unmineable coal seams.

This research was to be managed by the U.S. Energy Research and Development Administration (ERDA) and its Morgantown Energy Research Center (MERC).

ERDA became part of the Department of Energy (DOE), newly created in 1977, which was tasked with managing an Enhanced Gas Recovery (EGR) Program initiated by the FY 1978 Congressional Budget request. The goal of the Program was to "*develop and stimulate the deployment of advanced exploration, development and production technologies for recovering new gas supplies from the massive but complex unconventional gas resources – tight gas, coalbed methane, gas shales and geopressured methane. The technical objectives were to increase per well gas recovery efficiencies and lower unit development costs while providing incentives (through tax credits) for prompt, orderly development of the nation's gas resources*.[2]"

In addition, the Program had two quantitative, national-level natural gas supply goals:

1. Increase gas production by an incremental 3 Bcf per day by 1986, and
2. Add 10 Tcf of producible reserves by 1985.

The DOE R&D program that grew out of this initial effort was funded between $20 and 30 million dollars per year from 1978 thru 1981 (See Figure 1). The three programs begun by ERDA in 1976 were continued under this effort. The work continued to be managed by researchers at the now renamed DOE Morgantown Energy Technology Center (METC). The larger portion of this funding went towards the Eastern Gas Shales Program and Western Gas Sands Program, with a much smaller amount focused on the Methane Recovery from Coalbeds Project. Beginning in 1982 and continuing through 1992, there was also a small Methane Hydrates Program. Also, from 1982 through 1992 there was a Deep Source Gas program, and later, from about 1987 through 2000, a

[2] Kuuskraa, V., Guthrie, H., "Translating Lessons Learned from Unconventional Natural Gas R&D to Geologic Sequestration Technology," paper presented to the 1st National Conference on Carbon Sequestration, May 2001.

Secondary Gas Recovery program. Preliminary research into the geopressured methane resource added to the understanding of the actual potential of this resource, leading to the termination of R&D in this area.

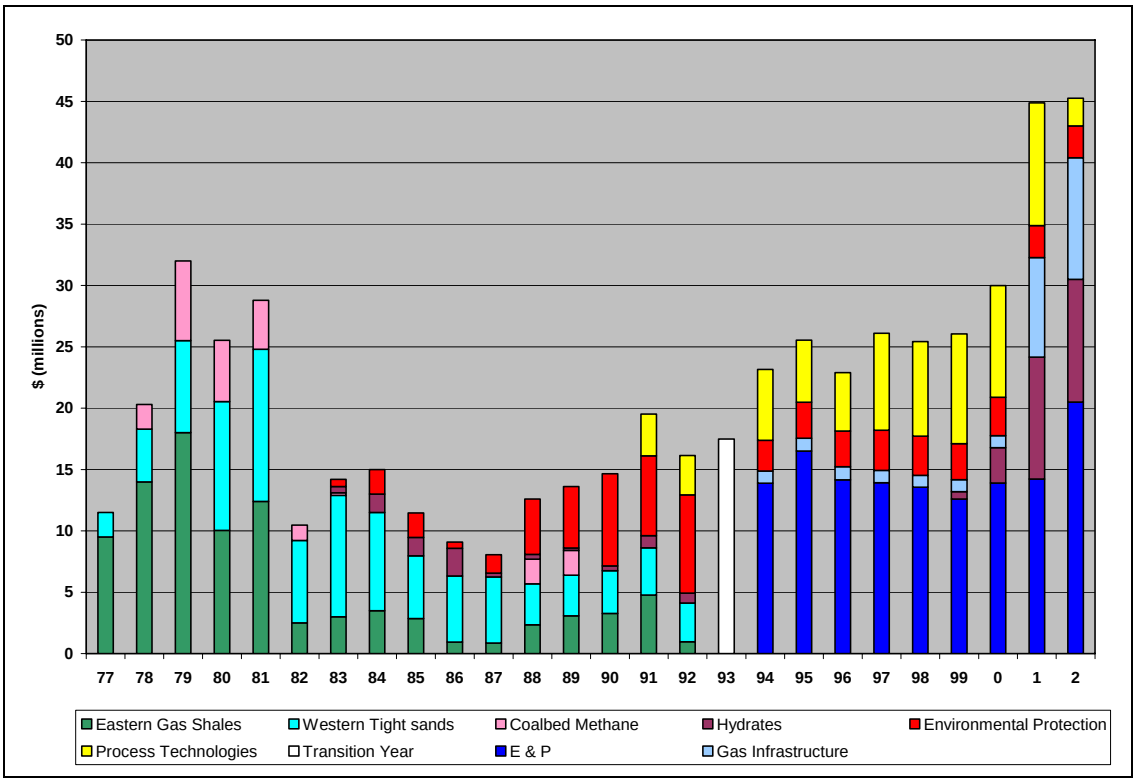

Figure 1: Funding of Various DOE Unconventional Gas Programs 1977-2002.

After 1980, the Reagan Administration implemented dramatic reductions in energy R&D spending, and the level of funding for the four-year-old DOE natural gas R&D program decreased to approximately $10 million per year through the majority of the decade of the 1980s. Funding for R&D related to natural gas E&P-related environmental protection technologies grew to be more than that directed towards E&P technologies themselves.

By 1992, much of the remaining DOE R&D program had been eliminated, with only a limited program related to Western Tight Sands surviving. In 1993 the DOE R&D program transitioned from its historical focus on unconventional gas resources to a *technology product* orientation, emphasizing tools and methodologies for drilling, imaging, diagnostics, completion and stimulation. From 1994 through 2005, funding for DOE R&D related to natural gas E&P has remained fairly steady in the range of $10 to $20 million per year.

2. GRI Research into Unconventional Gas Resources

The Gas Research Institute, founded in 1976 by the regulated gas industry and funded by a surcharge on interstate gas sales (as approved by the Federal Energy Regulatory Commission), had as its purpose the management and financing of a natural gas-related R&D program. GRI's budget grew from about $40 million in 1978 to about $75 million in 1981 and increased to an average of about $120 million per year through the 1980s (see Figure 2). In the 1990s GRI funding increased even further, averaging about $200 million per year. During this peak time, the amount of GRI funding focused on natural gas supply (exploration and production, including unconventional gas resources) was on the order of $30-35 million per year; about 15% of the total GRI budget.

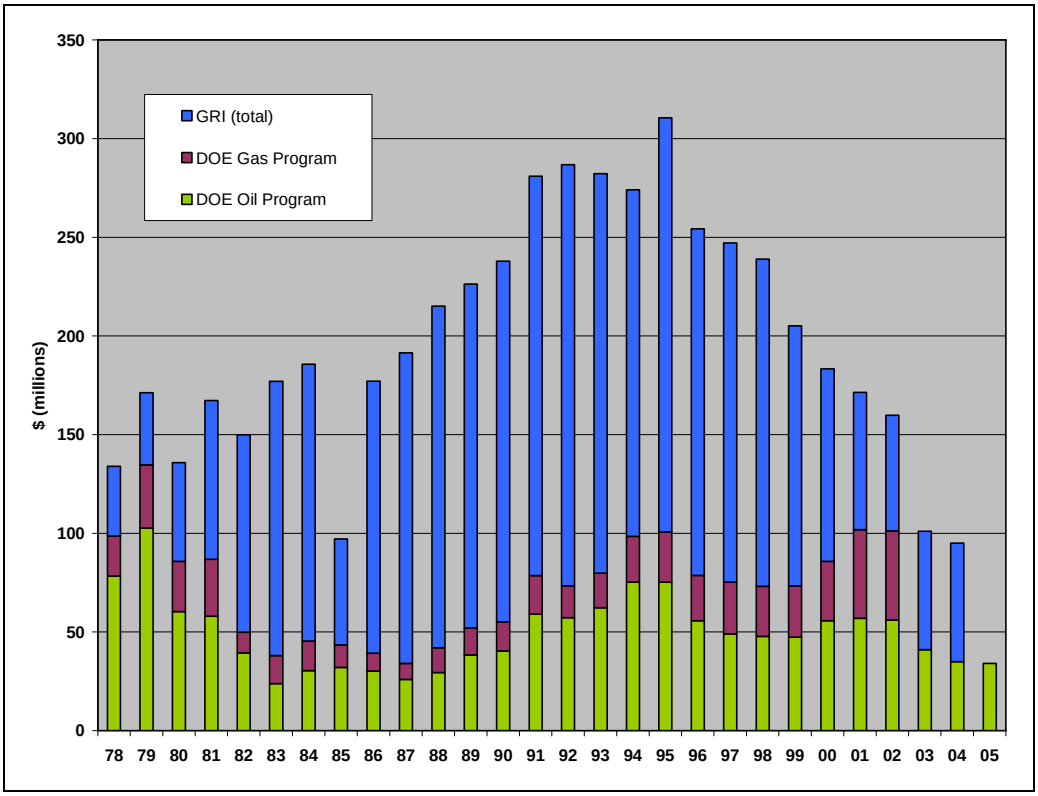

Figure 2: Funding of DOE Oil and Gas R&D Relative to GTI Funding 1978-2005.

The original DOE R&D program had the benefit of a considerable amount of industry technical input. In the early years, the DOE and GRI R&D programs were generally complementary, with the DOE program focused more on fundamental science and the GRI program focused on application and technology transfer. Both organizations funded

outside technical experts and industry partners to perform R&D and to help commercialize resulting products.

In 1994, the Gas Research Institute terminated its “resource-based” focus on unconventional gas and shifted it’s priorities to a generic technology-based R&D program, in much the same manner as had DOE had one year earlier. In 1998 GRI’s funding mechanism radically changed, leading to a phase out of the mandatory surcharge and a shift towards voluntary funding by industry and government. As a result, GRI funding of natural gas E&P R&D dropped steadily over the 1998-2005 time period. In 2000 GRI merged with the Institute of Gas Technology to form the Gas Technology Institute (GTI). By 2005, GTI had evolved into an organization totally funded by voluntary investments from client organizations, including the Department of Energy and other public entities. GTI’s natural gas E&P technology development at this point in time was minimal.

It is important to recognize that there was a significant degree of cooperation and coordination between the DOE and GRI research programs during much of their coexistence. That relationship effectively ended in 1998 when GRI’s funding mechanism changed and the organization began to submit competitive proposals in response to DOE R&D solicitations. Prior to that point, DOE representatives participated on guidance committees related to GRI natural gas E&P research and the two organizations conducted semiannual meetings to discuss high level planning direction and to make certain that research was coordinated and not duplicative.

During the 1980’s, research on tight gas sands at the DOE’s Multiwell Experiment (MWX) site in Colorado was transitioned to GRI-managed experiments using the same facility (M-Site). DOE worked closely with GRI to manage this transition in such a manner that research could be continued to the maximum benefit of the industry and ultimately, the gas consumer.

Similarly, DOE’s early funding of coalbed methane R&D provided a chance for the technologies being developed to show enough promise that further funding by GRI would be seen as practical by GRI’s industry advisory groups. Subsequently, DOE funding shrank while GRI’s went up significantly. DOE was viewed as the “initiator” and GRI (industry) as the “commercializer.” Both roles were important to the ultimate success that resulted as evidenced by the current important contribution of unconventional gas from both of these sources to the nation’s gas supply.

3. Structure of the Enhanced Gas Recovery Program (EGR)

The EGR focused on accelerating the production of gas from the eastern Devonian shales, western tight gas sands, coalbeds, and geopressured aquifers. Three of these targets were the focus of fairly significant R&D programs in terms of funding: the Eastern Gas Shales Program (EGSP); the Western Gas Sands Program (WGSP); and the Methane Recovery from Coalbeds Project (MRCP). Beginning somewhat later were two somewhat smaller (but still important) R&D programs focused on Methane Hydrates and Deep Source Gas (natural gas reservoirs sourced from very deep hydrocarbon sources, generally associated with subduction zones). There was also a small program dedicated to increasing recovery of natural gas from geologically complex reservoirs, Secondary Gas Recovery, that was funded jointly by DOE and GRI during the early 1990s.

3.1. Eastern Gas Shales Program (1976-1992)

Thick Devonian-age black shales underlie extensive areas of the eastern United States (Figure 3.1.1). Of the roughly 160,000 square miles of the Western Appalachian Basin, about 40 percent is underlain by Devonian shale deposits at depths of less than 4,000 feet and 60 percent at depths between 4,000 and 8,000 feet. The shale deposits of the Appalachian Basin, and to a lesser degree of the Michigan and Illinois Basins, have been recognized as gas productive since the late 1800s. By the end of the 1970s the shallower deposits had produced an estimated 3 Tcf. However, because Devonian shale wells produce at low rates (albeit for many years) this resource, along with the other unconventional natural gas resources targeted by the DOE's Unconventional Gas Resource R&D program, was historically viewed as relatively insignificant compared to conventional gas produced from highly permeable and porous sandstone and carbonate reservoirs. Very large ranges in estimates of gas-in-place (from less than 1,000 Tcf to 300 times that amount) and recoverable reserves (from less than 25 Tcf to as much as 285 Tcf) attested to the industry's relatively poor understanding of Devonian shale reservoir and production characteristics.

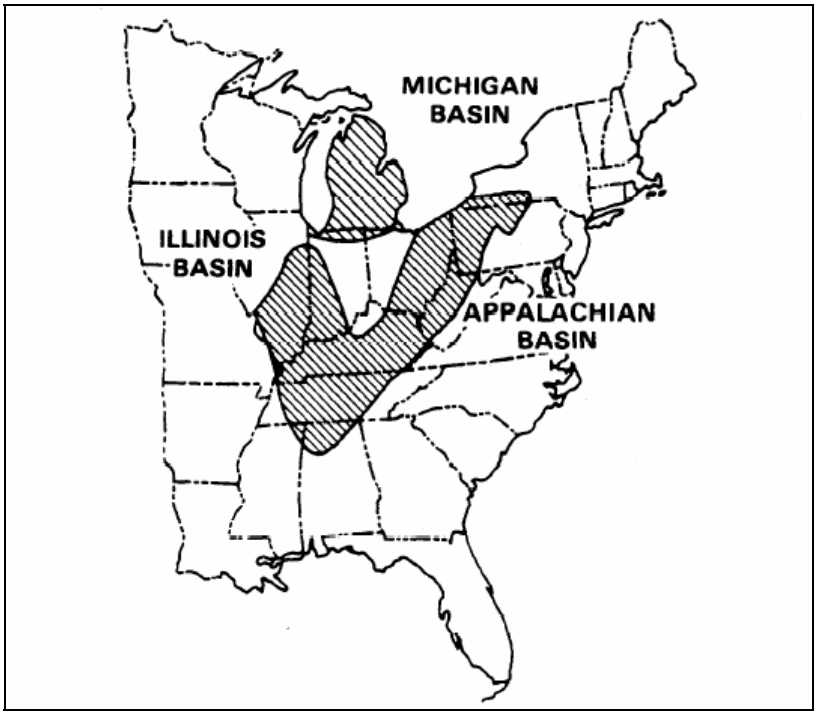

Figure 3.1.1: Extent of Eastern Gas Shales Distribution.

When domestic natural gas reserves began to decline in 1968, the U.S. Bureau of Mines (USBM) began to examine marginal gas resources to determine what methods might be employed to extract them. The USBM subsequently became part of the Energy Research and Development Administration (ERDA). The Eastern Gas Shales Project (EGSP) was formally initiated at ERDA's Morgantown Energy Research Center (METC) in 1976, just before that organization became part of the newly formed Department of Energy (DOE). EGSP funding continued through 1992. During that time period, several innovative and industry "firsts" were undertaken which later led to commercial technologies. In addition, the basic tools and methodologies developed for use in the Eastern U.S. led to a better appreciation for the potential of fractured shales in general. Subsequent drilling and development of the Barnett Shale of the Fort Worth Basin of Texas during the mid to late 1980s and the Lewis shale of the San Juan Basin of New Mexico, had its roots in the renewed interest in Eastern shales engendered by the EGSP.

The EGSP operated with a total budget of slightly more than $92 million over its 16 year history. Expenditures peaked in 1979, when the annual budget was $18 million. The first five years (1976-1981) of the EGSP concentrated on characterizing the geological, geochemical, geophysical, and reservoir properties of the Eastern gas shales, and on conducting cost-shared stimulation research (hydraulic fracturing, chemical explosive

fracturing, and directional drilling) experiments with oil and gas operators. Close to 38,000 feet of oriented core was obtained and 300 technical publications were published related to the results of this research.

Starting in the early 1980s, research emphasis shifted to detailed reservoir performance analysis and the development of a mathematical reservoir simulator for fractured shales. An Offset Well Test experiment was conducted in 1982/1983 in Ohio. The experiment consisted of drilling three closely spaced wells (<150 feet apart) and conducting a number of sophisticated production tests, including pressure pulse interference tests, to derive both matrix and fracture flow properties in the shale. Based upon this work (and the previously acquired characterization data), a fractured shale reservoir simulator (SUGAR-MD) was developed to quantify the inter-relationship of key parameters.

During the later stages of the EGSP, the research focused on validating the simulator through testing of ten single wells and the installation of a second, multiple well Offset Well Test Facility at one of the ten sites. Another major initiative was the drilling of a directionally controlled horizontal well to intersect the fractures in the shale and prove the concept that a horizontal well could produce at a flow rate six to eight times greater that that of standard vertical well. A medium radius directional well was drilled 2000 feet horizontally in December 1986. Initial flow rates were ten times the average for producing vertical wells in the vicinity.

Throughout the EGSP, a number of smaller contracts with universities and private R&D firms supported research in adsorption/desorption studies, database development, and reservoir performance predictive capabilities.

When the EGSP began in 1976, production from Devonian shales was on the order of 65 Bcf per year, almost entirely from the Appalachian Basin. By 1992, when the EGSP ended, natural gas production from this resource had climbed three fold, to 200 Bcf per year, with increased production from the Appalachian Basin and the onset of gas production from the Michigan (Antrim Shale), Fort Worth (Barnett Shale) and several other gas shale basins. Driven by the Section 29 tax credits and the boom in Antrim shale drilling, gas well drilling climbed sharply; 10,700 shale gas wells were drilled from 1978 to 1992 with an annual peak of 1,709 gas shale wells completed in 1992.

Since 1992, production from gas shales has continued to grow. In 2004 Appalachian shale gas production totaled 137 Bcf, Antrim 149 Bcf, Barnett 379 Bcf, and the newly developed Niobrara shale of the Williston Basin and Lewis Shale of the San Juan Basin totaled 23 Bcf, for a national total of 689 Bcf, more then ten times the annual total for shale gas production when the EGSP began.

The DOE R&D program in gas shales helped unlock a major new natural gas resource and source of significant natural gas supply. It revitalized gas shales drilling and development in the Appalachian (Devonian) Basin, helped initiate development of other previously over-looked gas shale basins, and took the lead in demonstrating much more efficient and lower-cost gas shales production and recovery technology. Without DOE involvement, the practical aspects of foam fracturing as a cost effective recovery method for shale gas wells would have never been discovered. Furthermore, the comparative analysis of various stimulation methods would not have been available to guide industry choices. The benefits of drilling horizontally through such naturally fractured formations would not have been realized as quickly without the efforts of the EGSP.

3.1.1. Key Questions and Related R&D Goals

Prior to the implementation of the EGSP there was considerable uncertainty about the magnitude of the potential shale gas resource that precluded industry from knowing where to drill. There was very little information available on the Devonian shale stratigraphic and structural framework in any of the eastern basins and state geologic surveys were not being funded to map such speculative resources.

Furthermore, nothing was known about the geochemistry of gas bearing shales or the degree of maturity necessary to support the presence of gas. Without cores, logs and maps of the shale gas depositional environment and tectonic activity, the knowledge base was lacking for exploration into this high risk, marginally economic resource.

Similarly, technology for recovery was limited to existing completion techniques (i.e., borehole shooting with explosives) that were becoming obsolete. The practical aspects of fracturing as a cost effective recovery enhancement method for shale gas wells had not been investigated. Furthermore, comparative analysis of alternative stimulation methods (e.g., foam fracturing, massive hydraulic fracturing, chemical explosives, propellants, or high density explosives) had not been done to any degree that could guide industry to choices that were suited to the variable natural fracture systems found in Eastern gas shales. Finally, the potential benefits of drilling horizontally through naturally fractured shales had never been investigated.

The EGSP was designed as a multidisciplinary research effort to provide the information that was lacking. The primary overall goals were:

- To develop technologies that would establish effective and environmentally acceptable means for locating and producing natural gas from Devonian shales, and
- To reduce the uncertainty surrounding the potential magnitude of reserves so that the private sector would be encouraged to develop the resource on a large scale.

Specific objectives of the EGSP were to:

- Develop accurate estimates of gas-in-place and economically recoverable resources,
- Develop exploration rationales for the identification of prospects, and
- Develop and improve cost-effective extraction methods.

3.1.2. Program Design and Overview of Major Projects

Early EGSP efforts were directed at determining the geologic character and magnitude of the Devonian shale gas resource and toward increasing production of natural gas from the resource base. Formation characterization required to update the resource knowledge base and geological evaluations to ascertain basin limits and stratigraphic targets as potential gas sources were the first tasks to be completed. With this understanding, researchers identified large areas of the Devonian shale that exhibited certain characteristics that required particular technological developments for extraction. Accordingly, EGSP activities were planned for each of a number of gas shale provinces (Figure 3.1.1), namely:

1. Then-productive areas of Kentucky and West Virginia.
2. Ohio and related areas in New York, Western Pennsylvania, and Northern West Virginia.
3. Appalachian Front in Pennsylvania, Maryland, West Virginia, and Virginia.
4. Deep Appalachian Basin in Pennsylvania and West Virginia.
5. Illinois and Michigan Basins.
6. Speculative areas in all Eastern states.

EGSP research identified the nature of producible gas containment to be the micro-fractures and macro-factures of the shale formation. Knowledge of these fractures, their directionality, and density enabled the development and testing of effective techniques to connect the gas-bearing natural fractures to the borehole. Pilot tests of stimulation techniques in light of the geologic environment in the respective gas provinces then permitted the development of a rationale for stimulation strategy.

The EGSP was structured into the following functional categories or program activities:

- Evaluation.
- Resource and Site Characterization.
- Research, Instrumentation, and Modeling.
- Production Technology Development.

The first three activities provided for resource data acquisition and the development and testing of techniques for locating probable areas of gas-bearing natural fracture systems and for predicting the probable production from a particular stimulation method in a certain geologic province. The fourth activity was directed at the development and testing of cost-effective methods for extracting gas from the various geologic provinces in the shale. Each of these program activities are briefly described below.

Evaluation – The Evaluation activity was designed to integrate facts as they developed, to assess recent technological developments and related industry activities, to ensure compliance with environmental regulations and address site-specific environmental problems, to develop a systems model for updating estimates of the potential resource, and to develop and monitor program plans that reflected the integration of the technical, geologic, economic, and other types of data.

Resource and Site Characterization – This activity of the project was structured to develop the necessary resource data base for characterizing the Devonian shale provinces and to develop exploration rationales. Core information was used to assess the potential of various resource areas, to guide modeling efforts, and to design stimulation tests. Types of data collected included stratigraphic, structural, sedimentological, physical, and chemical data for identification of gas-bearing fracture systems. Field work consisted of coring and logging to provide data for lab work. Laboratory research included chemical, physical, elemental, and mineralogical studies to determine the stratigraphic sources of gas and the degree of fracturing in the reservoir. The data was developed through contracts with universities and state geological surveys and the results were compiled and synthesized by the USGS for the various geologic provinces. Shale characterization studies were carried out through contracts with universities, research institutes, and private industry to develop and improve methods of locating gas-bearing naturally fractured reservoirs.

Research, Instrumentation, and Model Development – This activity in the project was directed at the development of new diagnostic tools, stimulation approaches, and predictive capability to accurately forecast reservoir performance whenever extraction methods are applied to particular geologic provinces in the Devonian shale. Meeting these objectives required basic and applied R&D in the laboratory and the field and the development of models. The models served to describe the current understanding of the stimulation processes, gas flow from the reservoirs, and economic parameters related to fracturing and production.

Production Technology Development – This activity in the project was directed at the development of effective stimulation methods for various geologic environments and the testing of these designs in field applications. The designs tested were conceptual models

that evolved from sequential laboratory and simulation studies. Detailed documentation of field tests under controlled conditions complemented with systematic well testing were conducted through cost-sharing contracts with private industry. Field tests (16) and demonstration projects showed that advanced stimulation technology (foam, cryogenic, MHF, and chemical explosive fracturing) could result in wells that produced considerably more than those stimulated with conventional wellbore explosive fracturing, at least in the gas province associated with historical shale production. Particular emphasis was placed on the use of energy assisted fracturing fluid in low-pressure fractured shale reservoirs. Directional deviated well technology was also investigated, as well as the relationship of frac length and reservoir permeability to productivity. Location of regions of increased fracture intensity was found to be required to assure the likelihood of a commercial well, and the stress ratio concept (minimum horizontal-vertical) was investigated as an estimator of fracture intensity.

The objectives of the EGSP that emphasized the definition and characterization of the Eastern Gas Shales as a resource were completed as planned and provided an important knowledge base and framework for exploration activity within three basins.

The objective of developing methods for extraction employed geologic and reservoir-engineering tests to understand/predict production performance in established areas of potential. This was necessary to separate the effects of the stimulation method employed from that of the reservoir itself. While the milestones for comparing stimulation methods in new areas of potential were completed as planned, the validation of a strategy for the matching of a specific technology to a given geology was not. This required a shift in project strategy from an R&D testing mode that produced gas to one that emphasized reservoir science. Accordingly, a three well, highly instrumented field laboratory was established to determine *in situ* gas storage, release mechanism and production rate, *in situ* natural fracture system spacing and distribution, response to stimulation, and well spacing required for development. This was successfully completed in one geologic province having production potential. The original EGSP plans to extrapolate this knowledge to new areas of potential was subsequently terminated and thus it was left to industry (motivated by tax credits) to assume this higher risk activity.

3.1.3. Key Eastern Gas Shales Projects

Listed below are the key Eastern Gas Shales projects undertaken during the 1977-1992 time frame. The primary Project Manager for the Eastern Gas Shales program during this time period was Chuck Komar. Other key technical project officers included: Albert Yost II, A. Crawley, K-H Frohne, G. Schott, Claude Dean, Clyde Pierce, Royal Watts, Larry Headley and Arlen Hunt.

Massive Hydraulic Fracturing Tests
Contracts: E(46-1)-8014, EF-76-C-05-5303
Performer: Columbia Gas Systems Service Corp. (Columbus, OH)
Key Investigators: W.F. Morse
Time Period: 1975 – 1978
Objectives: The objectives of this project were to demonstrate the potential of massive hydraulic fracturing treatments for improving the production of gas from fractured Devonian shales. Demonstrations were performed in West Virginia, Ohio, Kentucky and Virginia.

Gas Production Stimulation by Chemical Explosive Fracturing
Contract: E(26-1)-685, 686, 687
Performer: Petroleum Technology Corporation
Key Investigators: S. J. LaRocca
Time Period: 1976 – 1978
Objectives: To demonstrate the technical and economic feasibility of chemical explosive fracturing technology as an effective stimulation techniques for increasing gas deliverability from Devonian shale wells. Demonstration wells were stimulated in WV and KY.

Directionally Drilled Well in the Devonian Shale
Contract: E-(46-1)-8047
Performer: Consolidated Gas Supply Corporation
Key Investigators: T.A. Kuhn
Time Period: 1976 – 1977
Objectives: To test the feasibility of the concept that a gas well drilled at an angle from vertical will intercept more of the natural fracture system and thereby produce more gas at a higher rate. The specific objectives were to test the economic and technical feasibility of:

- Geophysical techniques (remote sensing, near-surface stress measurements, surface joint measurements and oriented core data) to determine the optimum location and preferred orientation of natural fracture systems in the Devonian shale, and
- Directional wellbores stimulated with multiple-staged hydraulic fracture treatments to improve deliverabilities and reserves of wells drilled in the Devonian shale.

Gas Well Fracturing in the Devonian Shale of Ohio
Contract: E(40-1)-5253
Performer: AMEX/VESCORP
Key Investigators: F. D. Ryan, J.M. Cochrane
Time Period: 1976 – 1979

Objectives: The primary objectives were to:

- Determine the effectiveness of remote sensing imagery as a tool to optimize well locations in the Devonian shale,
- Determine the relative effectiveness and quantitative benefit of foam fracturing and cryogenic fracturing to increase gas well production rates and reserves in the Devonian shale, and
- Determine if scaled-up versions of the better of the two types of treatments (foam or cryogenic fracturing) are cost effective techniques for improving gas well production rates and reserves in the Devonian shale.

Chemical and Physical Aspects of Eastern Shale
Contract: E-(40-1)-5205
Performer: Battelle Columbus Laboratory (Columbus, OH)
Key Investigators: J.R. Schorr
Time Period: 1976 – 1977
Objectives: The broad objectives of this project were to determine the relationships between shale characteristics, hydrocarbon gas content and well location to provide a sound basis for defining the productive capacity of the Eastern Devonian shale deposits and for guiding research projects.

Geologic and Geochemical Studies of the New Albany Group in Illinois
Contract: E(40-1)-5203
Performer: Illinois State Geological Survey
Key Investigators: R.E. Bergstrom, N.F. Shimp
Time Period: 1976 +
Objectives: The objectives of this project were to:

- Compile available well and outcrop data on the New Albany Group in IL, including data from oriented cores from ERDA wells
- Study stratigraphy and structure of the New Albany Group to determine relationship to occurrence of natural gas
- Characterize in detail the physical, mineralogical , chemical properties and hydrocarbon content, by detailed analyses of core material, and delineate high potential well locations,
- Characterize chemically the Eastern Shales to aid in evaluating their economic importance and in the exploration for natural gas.

Study of the New Albany Shale in Indiana
Contract: E(40-1)-5204
Performer: Indiana Department of Natural Resources
Key Investigators: J. B. Patton, D.D. Carr, R. K. Lenninger, L. Becker
Time Period: 1976 – 1977
Objectives: The objectives were to determine the magnitude of potential gas reserves, characterize the shale and improve the current stimulation technology for the New Albany Shale in Indiana.

Interaction Between Gases and Shale of the Eastern US
Contract: E(40-1)-5197
Performer: Juniata College
Key Investigators: P. Schettler
Time Period: 1976 – 1977
Objectives: To investigate shale samples canned at field coring sites to determine: 1) total adsorptive capacity and permeability, 2) degassing rates as a function of foreign gases, and 3) gas and mineral components.

Earth Fracture Systems for Energy Resource Exploitation
Contract: NA
Performer: METC In-House Research
Key Investigators: C.I. Pierce, et al.
Time Period: 1976 – through EGSP
Objectives: Perform a variety of tasks related to the correlation of fracture systems with productivity in shales, including:

- Description of lithology and fracture orientation of oriented cores.
- Preparation of lineament maps in Eastern Kentucky.
- Correlation of production trends with remote sensing data in various geologic settings.

Geochemistry of the Devonian Shale
Contract: NA
Performer: METC In-House Research
Key Investigators: J. Kovach
Time Period: 1976 – through EGSP
Objectives: To characterize the organic composition in the Devonian shales for use as an estimate of fuel potential and as geochemical indicators. To develop thermal techniques that will simulate various pyrolysis conditions so that fuel potential may be assessed.

Surface Chemistry and Spectroscopic Techniques for Characterization of Organic Constituents of Devonian Shales
Contract: NA
Performer: METC In-House Research
Key Investigators: J. Kovach
Time Period: 1976 – through EGSP
Objectives: To develop surface chemistry and spectroscopic techniques for the characterization of the physical, chemical and flow properties of Devonian shales.

Development of Marginal Gas Resources by Fracturing
Contract: NA
Performer: METC In-House Research
Key Investigators: Karl-Heinz Frohne, G.E. Rennick, A.B. Yost, D.M. Evans
Time Period: 1967 – through EGSP
Objectives: To perform a variety of R&D related to the development of improved methods for locating wells near naturally fractured zones or improving fracture stimulation treatments designed to connect the wellbore to such natural fracture systems.

Physical and Chemical Characteristics of Devonian Shale Samples
Contract: NA
Performer: Mound Laboratory
Key Investigators: R.E. Zielinski, E.W. Johnson
Time Period: 1976 – 1977
Objectives: Perform fuel yield analyses, chemical characterization of fuel, and detailed characterization of kerogen material from shale samples. Determine the relationships of hydrocarbon release to mechanical loading of shale samples in the laboratory. Determine spectroscopic and microscopic physiochemical characteristics of organic and inorganic species in shale.

Eastern Gas Shales Project Study of the Upper Devonian Shale in Ohio
Contract: EY-76-C-05-5200
Performer: Ohio Department of Natural Resources
Key Investigators: R.A. Struble
Time Period: 1976 – 1977
Objectives: To determine the magnitude of the potential gas reserves, characterize the shale and improve the current stimulation technology for the Devonian Shale in Ohio.

Stratigraphic Framework for the Middle and Upper Devonian Black Shales and related Rocks of Western and central Pennsylvania
Contract: E(40-1)-5198
Performer: Pennsylvania Topographic and Geologic Survey

Key Investigators: R. G. Piotrowski
Time Period: 1976 – 1977
Objectives: Provide a stratigraphic framework for the Black Shales and related rock units found between the Onondaga Limestone and the Berea-Cussewago-Murrysville interval in the subsurface rocks of western and central Pennsylvania.

Evaluation of the Chattanooga Shale in the Tennessee Valley and Ridge for Natural Gas and Uranium
Contract: EY-76-C-05-5196
Performer: Tennessee Department of Conservation
Key Investigators: A. T. Statler
Time Period: 1976 – 1977
Objectives: The objectives were to document the regional structure and stratigraphy in the Tennessee Valley and Ridge, locate the Chattanooga members which contain high hydrocarbon values, identify by seismic profiles the location of tectonically fractured zones in the Chattanooga shale, and evaluate the potential of the shale for natural gas and uranium.

Geological, Geochemical, and Geophysical Appraisal of Energy Resources of the Devonian Black Shale in the Appalachian Basin
Contract: E- (49-18)-2287
Performer: US Geological Survey
Key Investigators: W. deWitt Jr.
Time Period: 1976 – 1977
Objectives: To correlate a thorough characterization study of the Devonian black shale in the Appalachian basin and to make a detailed appraisal of the resource potential of the shale sequence, with particular emphasis on the natural gas resource. Work included geologic, geochemical and geophysical study to determine the extent, geometry and hydrocarbon potential of the black shale, as well as the relationship of the shale to other types of rock.

Energy Resources of the Devonian Shale in the Appalachian Basin
Contract: E(40-1)-5201
Performer: University of Cincinnati
Key Investigators: P.E. Potter, J. B. Maynard, W.A. Pryor
Time Period: 1976 – 1977
Objectives: To provide special geochemical and petrologic studies of the Devonian Shale in the Appalachian basin and to prepare a depositional model for the entire basin.

Black Shale Study in Kentucky
Contract: E(40-1)-5202
Performer: University of Kentucky Research Foundation
Key Investigators: W.H. Dennen, F.R. Ettensohn, E.N. Wilson, W.A. Hagan
Time Period: 1976 – 1977
Objectives: To collect and analyze available drill hole and outcrop data on the Devonian Shale of eastern Kentucky, study the shale's sedimentary history and stratigraphic framework, provide detailed lithologic and geochemical analyses of core material. Provide a data bank for the physical, geochemical, stratigraphic and geological information generated by the Kentucky Research Group, the Illinois Geological Survey, the USGS and ERDA, and archive core taken by ERDA from wells in Kentucky.

Stratigraphy and Petrography of the Tioga Bentonite
Contract: E(40-1)-5195
Performer: University of North Carolina (Chapel Hill, NC)
Key Investigators: J. M. Dennison
Time Period: 1976 – 1977
Objectives: To study the stratigraphy of the Tioga Bentonite and its relationship to that of the Devonian Shale and to characterize the bentonite petrographically. The Tioga Bentonite is a thin bed of volcanic ash deposited during a relatively brief time interval throughout most of the Appalachian Basin.

Eastern Gas Shales Project
Contract: E(40-1)-5206
Performer: University of the State of New York
Key Investigators: A. M. Van Tyne, L.V. Rickard
Time Period: 1976 – 1977
Objectives: To perform major stratigraphic and structural geologic investigations, using production data, core data, geophysical logs, and aerial photographs to construct maps and cross sections which define the extent and productive capacity of the Devonian age black shales of New York.

Analysis of Structural Geological Parameters that Influence Gas Production from the Devonian Shale of the Appalachian Basin
Contract: E(40-1)-5914
Performer: West Virginia University
Key Investigators: R.C. Shumaker
Time Period: 1976 – 1977
Objectives: The objectives of this work were to:

- Determine if structural types and styles, surface lineations, and ground water movement for productive areas of the Devonian Shales differ from those in non-productive areas,
- Determine the feasibility of using shallow penetration resistivity and seismic surveys to detect near-surface faults and fractures and demonstrate their relationship to lineations observed on airborne imagery,
- Identify and define along with other contractors those geologic parameters that control gas production from the shales, and
- Develop a method for selecting areas for drilling shale wells that have a potential for gas production.

Directional Rock Properties
Contract: E(40-1)-8028
Performer: West Virginia University
Key Investigators: S. Peng
Time Period: 1976 – 1977
Objectives: To measure the directional properties of Devonian shale samples, determine their relationship to preferred direction of fracturing, and determine the feasibility of developing a directional wireline tool for in situ stress measurements and orientation of fractures.

Earth Fracture Systems
Contract: E(40-1)-8040
Performer: West Virginia University
Key Investigators: R.C. Shumaker
Time Period: 1976 – 1977
Objectives: To study photo lineaments, fracture systems and fold and fault patterns of southwestern West Virginia, Virginia and eastern Kentucky, to determine what effects these features have on the fossil fuel extraction processes, and to study the different styles and trends of deformation such as the detached deformation of the folded Appalachians, normal fault trends of eastern Kentucky and thrust structures typical of the southern Appalachians.

Characterization and Evaluation of the Devonian Shales in West Virginia
Contract: E(40-1)-5199
Performer: West Virginia Geological Survey (Morgantown, WV)
Key Investigators: L. Woodfork, D. Patchen, R. Lareses, M. Behling, J. Renton
Time Period: 1976 – 1977
Objectives: Prepare a comprehensive appraisal of the total energy resource potential of the Devonian Shale in West Virginia that features stratigraphy, petrology, geochemistry, and data processing.

Massive Hydraulic Fracturing Program for Gas Stimulation
Contract: NA
Performer: Lawrence Livermore Laboratory (Livermore, CA)
Key Investigators: M.E. Hanson
Time Period: 1977+
Objectives: To develop a data base and predictive methods for improving gas stimulation from tight sands and shales by massive hydraulic fracturing and related techniques.

Explosive Stimulation and Laser Characterization Methods for Devonian Shales
Contract: NA
Performer: Los Alamos Scientific Laboratory (Los Alamos, NM)
Key Investigators: W.J. Carter, N.E. Vanderborgh
Time Period: 1977+
Objectives: To develop and evaluate selected methods for stimulation and characterization of Eastern shales.

Natural Gas Massive Hydraulic Facture Research and Advanced Technology Project
Contract: NA
Performer: Sandia Laboratories (Albuquerque, NM)
Key Investigators: H. M. Stoller
Time Period: 1977+
Objectives: To develop and verify methods to determine the orientation and extent of hydraulically produced underground fractures and investigate the influence of geologic factors on fracture geometry

3.1.4. Highlights of Important Results

Between 1976 and 1992, the EGSP catalyzed several innovative industry "firsts" that later became commercial technologies or products. In addition, the EGSP resulted in the acquisition and wide dissemination of an enormous quantity of geologic and production data about Eastern gas shales. This data led to important new insights into the nature of shale gas reservoirs and the mechanisms behind their production. Highlighted below are the key technology products and E&P methodologies that resulted from the EGSP.

Foam Fracture Technology – The EGSP was responsible for the first use of nitrogen foam fracture technology in the Devonian Shale in 1975. Prior to this time, shale wells had been explosively stimulated in open-hole well bores (no casing across producing formation) and water fracs had been used to improve production. Foam fracture

stimulation technology allowed sand to be transported by the fracture fluid while simultaneously reducing the volume of water used by 75 to 90 percent as compared to conventional water fracs. The incremental cost of foam fracs was offset by reduced well cleanup costs and improved productivity. More than 50 cost-shared foam frac demonstrations were conducted with industry during the first four years of the program. By 1979, foam fracturing was the preferred commercial method of stimulation for Devonian shale gas wells and commercial services were widely available to operators in the eastern United States.

Oriented Coring and Fractographic Analysis – In 1977 the EGSP carried out the first oriented coring and fractographic analysis of Devonian shale to detect natural fractures. The use of oriented core was an innovation which allowed not only the detection and location of natural shale fractures, but also allowed for the determination of both fracture azimuth and dip -- key parameters in determining geologic structural trends, gas production mechanisms, reservoir modeling parameters and reservoir anisotropy. Subsequently, oriented coring and fractographic analysis became commercially available to operators seeking to reduce their risk of drilling underperforming shale wells. Coring techniques developed through the EGSP were also employed in DOE sponsored research related to western tight sands (see Section 3.2). The core analysis techniques developed for identifying natural and core-induced fractures have since been used throughout the US to evaluate low-permeability gas reservoirs.

Devonian Shale Logging Suite – As part of the EGSP, DOE worked with the well logging service industry to jointly develop an electric downhole well logging suite for air-drilled bore holes, consisting of gamma ray, caliper, compensated density, temperature and noise logs. This suite was developed to permit the determination of lithology and production potential of the shale in air-drilled holes. Most previous logging had required water or mud-filled wellbores, liquids which damaged the permeability of the fluid-sensitive shales. By 1985, a commercially available Devonian well logging suite was being used by industry within the Appalachian Basin.

Role of Adsorption in Devonian Shale Production Mechanism – The EGSP carried out research that resulted in the recognition of the contribution of absorbed gas and fracture systems to the shale gas production mechanism. Gas desorption data derived from canned samples taken from Devonian shale oriented core collected by the EGSP demonstrated the importance of the desorption mechanism to long-term gas production. Canned samples from 35 cored wells were used to carry out the first widespread characterization of Devonian shale gas content and to prepare gas resource estimates based on a much improved fundamental understanding of the nature of the shale reservoir rock. Widespread industry knowledge of the role of absorbed gas and the accompanying mechanism for gas flow through a network of interconnected natural fractures permitted

the development of more accurate production models that incorporated dual porosity/dual permeability fluid flow in the reservoir. This in turn resulted in better tools for reserve estimates and economic decision-making by industry. The early development of dual porosity reservoir models also paved the way for later work in support of similar models for coalbed methane production.

Downhole Video – The EGSP carried out the first use of a downhole video camera in the history of U.S. oilfield operations. DOE began the use of downhole video by designing and testing a downhole underwater camera for viewing the wellbore of a Devonian shale well in Ohio, in an effort to identify fractures contributing to gas flow. The service company contractor subsequently opened an office in Ohio and developed a commercial downhole camera service. By 1981, downhole video camera services had been commercialized in the eastern U.S. with multiple companies operating in Ohio, Kentucky and West Virginia.

Large-scale Massive Hydraulic Fracturing – The EGSP introduced large-scale Massive Hydraulic Fracturing (MHF) to the Eastern Devonian shale marketplace. This type of stimulation, used to place large volumes of sand proppant into the shale formation to lengthen the induced fracture length and increase connectivity with the gas-bearing natural fracture system within the shale, had not previously been employed for stimulating shale wells. By 1990, commercialization of MHF stimulation allowed industry to recognize the benefits of such large scale stimulations in targeted shale areas.

Directional Drilling to Improve Productivity – In 1975, a pre-EGSP DOE-industry collaborative effort resulted in the first Appalachian Basin high-angle Devonian shale directional well in Mingo County, WV (ultimate inclination of 43 degrees). This was followed up in 1978 with the first EGSP Devonian shale high-angle directional well, a joint well in the Cottageville gas field, Jackson County, WV (ultimate inclination of 52 degrees). Again, in 1986, DOE and industry partners drilled the first air-drilled horizontal well Devonian shale well in Wayne County, WV, having a total horizontal displacement of 3,186 feet from vertical at a measured depth of 6,020 feet. Among a number of other “firsts” this well also recorded the first recovery of core from a horizontal, air-drilled Devonian shale well, the first horizontal well where external casing packers (ECP’s) were successfully installed and inflated in an air-filled wellbore, and the first horizontal well to complete seven individual hydraulically fractured intervals. In 1989 and 1990, three additional DOE/industry jointly-sponsored Devonian shale horizontal wells were drilled and completed: a 1,789-foot horizontal well (measured depth of 6,399 feet) in Putnam Co., WV, a 1,985-foot horizontal well (measured depth of 6,263 feet) in Martin Co., KY, and a 1,617-foot horizontal well (measured depth of 5,013 feet) in Calhoun Co., WV. These cost-shared demonstration wells identified the technical barriers to widespread application of underbalanced horizontal drilling in the

United States. DOE's follow-on R&D programs continued to develop new underbalanced vertical and horizontal drilling products and formed the basis of its leadership role in underbalanced drilling.

Electromagnetic Measurement-While-Drilling – Wells drilled as part of the EGSP saw the first use of electromagnetic measurement while drilling (EM/MWD), where it was introduced as a method for steering downhole motors during drilling of a Devonian shale horizontal well. Initial runs were encouraging and resulted in further tool development. More than 13 field tests of EM/MWD were conducted during and after the EGSP program and the tools were used commercially in the US mid-continent and west coast as well as in western Canada. Based on this success, DOE's subsequent Natural Gas Supply R&D program continued to fund the research from 1992 to 1998.

Carbon Dioxide Fracture Treatment – The very end of the EGSP saw the first successful use of CO_2/Sand stimulation in Devonian shale wells; a technology introduced into the United States by this program. A total of five CO_2/Sand well stimulations were executed for two operators in Perry and Pike counties, KY. These tests were funded by the EGSP program in 1991/1992. CO_2/Sand stimulation subsequently became one of the stimulation options used in the San Juan Basin on a commercial basis.

Other equally important results of the EGSP that increased the knowledge base related to the Devonian shales and aided in subsequent exploration for and development of this vital energy source include the following:

- Methods for geologic integration of well logs, core data, geophysical survey results, and remote sensing interpretations into a suite of E&P tools for identifying organic source rocks and detecting enhanced fracture density in the Devonian shales.
- Basic knowledge gained from the collection of 25,000 feet of oriented core from more than 35 wells and the geochemical, fracture characterization, and detailed lithological analyses carried out on the core.
- More than 120 detailed maps and cross sections provided to industry as part of the first detailed descriptions of the distribution of high organic content, gas-productive, fractured shales over a large portion of the Appalachian Basin. Structural and stratigraphic maps provided information on the influence that deep basement faulting and tectonics had on the location of shallower faults and fracturing. Present day stress orientations and stress ratios were mapped to identify areas of greatest gas production potential. These data were assembled through an integrated effort of the oil and gas industry, State geological surveys, USGS and DOE contractor efforts. Studies were extended to include organic shales in the Illinois and Michigan Basins.
- As a result of detailed Devonian shale structure mapping during the EGSP, a northeast-southwest structural fold (anticline) was found in southwestern New York.

This trend, which was subsequently extended through northwestern Pennsylvania and into northeast Ohio, is a highly productive, faulted limestone trend (termed the Bass Island trend) located stratigraphically below, but unassociated with, the Devonian shale. Without the detailed structural mapping carried out by the EGSP, this productive oil and gas trend may not have been located.

- An extensive bibliography related to Devonian shale gas exploration activities in the Appalachian, Michigan and Illinois Basins that was made available to industry through NETL and the state geological surveys.
- A methodology was developed for integrating data that facilitates interpretation of the history of a basin's development and the potential of the sediments and organic matter to produce petroleum and natural gas. The result, a better understanding of when gas and oil are generated and the geometry of the basin when these fluids migrate, allows industry to identify the areas of highest potential for gas trapping mechanisms as targets for development.
- Knowledge of Devonian shale production mechanisms developed as part of the EGSP was useful to operators developing the Barnett and Lewis shale resources during the decade following the EGSP.

The DOE was asked to quantify the overall benefits of the EGSP as inputs to the National Research Council report titled *"Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000"* published in 2001. Estimates were calculated for three time periods - the 1978 to 1992 period when the program was active; the 1993 to 1998 period for which data on impacts are available; and, the 1999 to 2020 period based on a projection using the EIA/NEMS natural gas model. The benefit measures used are - annual gas production, additional supplies of natural gas and new well drilling.

The baseline starting point was 1978 with a declining Appalachian Basin shale production industry providing 70 Bcf of annual production, drilling 200 wells per year, and holding a reserve base of 1,000 Bcf. Based on analogs with other natural resource R&D programs (such as the benefits study by GRI's R&D program on coalbed methane in the San Juan and Warrior basins), the DOE EGSP was allocated responsibility for 50 percent of the impact and benefits in the Appalachian Basin during Periods 1 and 2, and 25 percent of the impact during Period 3. This approach considered not only the production that would have occurred in the absence of the program, but also production induced by the existence of Section 29 tax credits under the Natural Gas Policy Act, and incremental production resulting from the R&D activities of the Gas Research Institute.

The knowledge base and technologies developed by the EGSP found ready application in other domestic gas shale basins (e.g., the DOE R&D program undertook the initial R&D effort in the Antrim Shale of the Michigan Basin, which was subsequently pursued by

GRI and industry). As a result, the DOE R&D program was allocated responsibility for 10 percent of the impact and benefits in other gas shale basins.

These assumptions resulted in an estimated impact resulting from the EGSP of an incremental 4.17 Tcf in gas supply, 7.83 Tcf in proven reserves and 10,600 wells drilled over the 1978-2020 time period. One of the benefits attributable to the additional gas supplies are the state and federal tax revenues received from the sale of the gas. The dollar value of the benefits from state and federal tax revenue of the EGSP was calculated at $1,040 to $2,080 million using a conservative value of $0.25 to $0.50 per Mcf for the additional gas supplies. Using the total cost of $92 million, the undiscounted benefit/cost ratio would be 10:1 to 20:1, based on incremental tax revenue alone. At current gas prices, the revenue impacts and benefit/cost ratio would be considerably greater. In addition, DOE estimated over $8 billion in consumer savings due to lower gas prices.

National Research Council report found that,

> *"The EGSP was responsible for bringing together and integrating a significant amount of scattered data on the Eastern gas shales critical to a solid assessment of the resource base. Such an assessment was, as is always the case, necessary for the optimum deployment of technology. … Although the in-place shale gas resource base in the United States is large, it is marginal and produced in relatively small increments. At the time ERDA, and later DOE, began the program in the Eastern gas shales, the conventional wisdom was that any significant expansion of production would require relatively high gas prices and that technology in these formations could do little to substitute for high prices. But incentives through tax credits, combined with optimum deployment of advanced technology, served to revive a domestic gas province in decline. … In a significant way, technology can and does substitute for price in marginal resources, and the Eastern Gas Shales program proved that critical point."*

Table 3.1.1 provides a list of key reports that contain the most important results associated with EGSP research projects. These reports, as well as a number of other associated technical notes, interim reports, topical reports and proceedings have been collected on the accompanying CD. Table 3.1.2 lists the status of logs and core reports associated with the Devonian shale wells drilled as part of the EGSP.

3.1.5. Subsequent Developments in DOE and Other Research Related to Eastern Gas Shales

The R&D efforts of DOE and GRI were well coordinated during the latter phases of the EGSP. As EGSP funding declined during the late 1980s, GRI funding focused on gas shales increased. GRI followed a path that was very similar to DOE's, working with

industry to drill and complete joint wells where detailed data-gathering and analysis could be used to demonstrate a scientific basis for alternative approaches to conventional drilling, formation evaluation and well stimulation/completion practices. A series of five Comprehensive Study Wells in West Virginia and Kentucky helped to highlight the economic benefits of new technologies for locating, stimulating and producing gas wells in the Appalachian Basin. GRI also focused on ways that operators could improve well performance by focusing on quality control during data acquisition and completion operations, an emphasis that had been lacking in Devonian shale drilling operations prior to that point. From 1992 through 1996, GRI R&D efforts focused increasingly on the active Antrim shale trend in the Northern portion of Lower Michigan. This fractured shale exhibited water-filled fractures that had to be de-watered before the gas would desorb, similar to coalbed methane wells.

At the same time, a portion of DOE's post-EGSP R&D efforts have remained focused on the development of technologies that could help shale gas producers. In particular, efforts to develop new geophysical technologies for locating natural fractures, new methods for characterizing and modeling fractured reservoirs, and new tools for lowering the cost of marginal gas well production in Appalachian Basin. The Stripper Well Consortium, a DOE-industry collaborative effort that has invested $7.1 million to fund 62 projects since 2001, recently approved nine new R&D projects in April 2006. Three of these projects propose improvements to methods for the removal of liquids from marginal shale gas wells, a perennial problem for stripper well operators that receives little attention from the larger service companies.

Table 3.1.1: List of Major Research Reports for Eastern Gas Shales Program (1976-1992).

Report Number	Title	Authors	Organization	Date
UCID-20614	A Geostatistical (Kriging) Study of Geological and Gas Production Data from West Virginia	Mao, N.	Lawrence Livermore National Laboratory	1986 Jan
	A Preliminary Assessment of the Natural Gas Potential of the New Albany Shale Group in Illinois.	Cluff, Robert M.	ILGS	1979 Oct
	A Statistical Analysis of Geochemical Data for the Eastern Kentucky Gas Field.	Cheng, Jean	WVU Dept of Geol. & Geog	1980 Mar
	A Study of Stress in Devonian Shales of the Appalachian Plateau (Final Report)	Evans, K.F., Engelder, T.	Schlumberger-Doll Research, Exxon	1987 Jul
	Amex-Vescorp Phase 1 Report, Eastern Gas Shales Project, Eastern Gas Shales Project.		Amex-Vescorp	1977 Jan
	Analysis of Devonian Shale Gas Production Mechanisms (Application to Devonian Shales of Ohio)		Lewin and Assoc.	1983 Jan
	Analysis of Devonian Shale Production Mechanisms		Lewin and Assoc.	1982 Sep
	Analysis of Fracturing Mechanisms in Naturally Fractured Rocks (Final Report)	Blanton, T.L., Thompson, T.W., Mann, K.L., Zeigler, B. J.	Science Applications International Corp.	1987 Aug
	Analysis of Fracturing Mechanisms in Naturally Fractured Rocks (Final Report)	Blanton, T.L., Thompson, T.W., Mann, K.L., Zeigler, B. J.	Science Applications International Corp.	1987 Aug 5
	Analysis of Gas Production for Eastern Gas Shales, Phase II Final Report.		Intercomp Resource Development and Engineering, Inc.	1979 Nov
	Analysis of Gas Production From Eastern Gas Shales, Phase 1 Final Report,		Intercomp Resource Development and Engineering, Inc.	1979 Apr
	Analysis of Structural geological Parameters that Influence Gas Production from the Devonian Shale of the Appalachian Basin.	Shumaker, R.C.; Kirk, K.G.; Nuckols, E.B.; Long, B.R. (WVU)	West Virginia Geological Survey and West Virginia University	1977

Report Number	Title	Authors	Organization	Date
DOE/MC/14693-1296 (Vol. 1)	Analysis of the Devonian Shales in the Appalachian Basin (Vol 1)		Cliffs Minerals, Inc.	1982 Sep
DOE/MC/14693-1296 (Vol. 2)	Analysis of the Devonian Shales in the Appalachian Basin (Vol 2 Appendices)		Cliffs Minerals, Inc.	1982 Sep
	Assessment of Michigan Basin Shale Characterization Research and Results (Final Report)	Science Applications, Inc.	Science Applications, Inc.	1979 Jul 3
	Atlas of Upper Devonian/Lwr Mississippian Sandstones in the Subsurface of West Virginia	Boswell, R.M., Jewell, G.A.	WV Geological Survey	1988
	Characterization and Analysis of Devonia Shales as Related to Release of Gaseous Hydrocarbons, (multiple reports for individual EGSP wells)	Kalyoncu, R.S.; Boyer, J.P.; Snyder, M.J.	Battelle Columbus Laboratories	1979
	Characterization and Hydrocarbon Resource Appraisal of Middle and Upper Devonian Shales in New York.		New York Geological Survey	1980 Oct
	Characterization and Resource Assessment of the Devonian Shales in the Appalachian and Illinois Basins.	Zielinski, Ronald E.; Nance, Steven W.	Mound Facility	1979 Oct
ISGS 1985-4	Chemical Composition and Geochemistry of the New Albany Shale Group (Devonian-Mississippian) in Illinois	Frost, J.K., Zierath, D.L., Shimp, N.F.	Illinois State Geological Survey	1985 Oct
	Chemical Explosive Fracturing of Devonian Shale Gas Wells.	LaRocca, S.J.; Spencer A.M.	Petroleum Technology Corporation	1978 Jun
	Chemical Explosive Fracturing, Devonian Shale and Canyon Sands, Final Report.	Petroleum Technology Corporation	Petroleum Technology Corporation	1979 Dec
	Cliffs Minerals Core Reports (multiple reports, Phases 1, 2 and 3 for each EGSP well)		Cliffs Minerals	1980-1982
DOE/METC-145	Comparative Analysis of Stimulations in the Eastern Gas Shales	Horton, A.I.	DOE-METC	1981

Report Number	Title	Authors	Organization	Date
MERC/TPR-76/1	Comparison of Conventional Hydraulic and water/Nitrogen foam Fracturing in Two Ohio Devonian Shale Gas Wells.	Frohne, K-H	MERC,	1976 Feb
	Completion and Stimulation of Five NYSERDA wells, Allegany and Cattaraugus Co.'s, NY (Final Report)	Rdissi, A.	Gruy Federal, Inc.	1981 Nov
	Coordination of Study of the Devonian Black Shales in the Illinois Basin.		Illinois Geological Survey	1978 Jun
	Current Investigation of Devonian Shale by the U.S. Geological Survey.	DeWitt, Wallace	USGS	1976 Oct
USGS 80-707	Defining Organic Rich Facies in the Devonian Shale in the Western Part of the Appalachian Basin.	Schmoker, James W.		1980 Oct
	Depositional Model for the Devonian-Mississippian Black-Shale Sequence of North America: A Tectono-Climatic Approach.	Ettensohn, Frank R., Barron, Lance S.		1981 Jan
	Development of Rationale for Stimulation Design in the Devonian Shale.	Komar, C.A.	MERC	1978 Jun
	Devonian Black Shale Study of Kentucky, Contract No. EW-78-S-21-8215 Final Report.	Beard, John	KYGS and U. KY	1978 Oct
	Devonian Shales of Ohio and Their Eastern and Southern Equivalents.	Schwietering, Joseph F.	WVGS METC/CR-79/2	1979 Jan
	Directional Drilling for Extraction of Devonian Shale Gas	Lewin and Assoc.	prepared by Lewin and Assoc. for METC. No document number	1985 Apr 30
MERC/TPR-76/3	Drilling a Directionally Deviated Well to Stimulate Gas Production from a Marginal Reservoir in Southern WVA	Overby, W.K., Ryan, W.M.	MERC	1976 Jul
DOE/MC/19146-1400	Drilling of a Deviated Well	Rodgers, J.A.	Gruy Petroleum Tech. Inc.	1982 Sep 30

Report Number	Title	Authors	Organization	Date
	Eastern Gas Shales Project (EGSP) Data Files: A Final Report.	Dyman, Thaddeus S.	USGS 81-598	1981 Oct
DOE/METC/SP-207	Eastern Gas Shales Subprogram (Topical Report)	DOE-METC	DOE-METC	1984 Feb
	Economic Analysis of Foam Fracturing in the Devonian Shales, Preliminary Report.	Liebenthal, A.; Komar, C.A.; Rieke, H.H.; Skillern, C.R.	SPE/AIME, SPE 8738	1979 Oct
	Effectiveness of Hydraulic Fracturing Treatments in the Devonian Shale.	Yost II, Albert B,	METC	1978 Jun
	EGSP Study of the Upper Devonian Shale in Ohio.	Ohio Geological Survey	DE-AS05-76MCO5200	1979 Oct
	Estimates of the Unconventional Natural Gas Resources of the Devonian Shale of the Appalachian Basin		USGS	1982
	Evaluation of Devonian Shale Potential in Eastern Kentucky/Tennessee	TetraTech, Inc.	Tetra Tech, Inc. DOE/METC-121	1981
	Evaluation of Devonian Shale Potential in Michigan Basin.	TetraTech, Inc.	Tetra Tech, Inc. DOE/METC-123	1981
	Evaluation of Devonian Shale Potential in New York	TetraTech, Inc.	Tetra Tech, Inc. DOE/METC-118	1981
	Evaluation of Devonian Shale Potential in Ohio	TetraTech, Inc.	Tetra Tech, Inc. DOE/METC-122	1981
	Evaluation of Devonian Shale Potential in Pennsylvania	TetraTech, Inc.	Tetra Tech, Inc. DOE/METC-119	1981

Report Number	Title	Authors	Organization	Date
	Evaluation of Devonian Shale Potential in the Illinois Basin.	TetraTech, Inc.	Tetra Tech, Inc. DOE/METC-124	
	Evaluation of Devonian Shale Potential in West Virginia.	TetraTech, Inc.	Tetra Tech, Inc. DOE/METC-120	1979
	Evaluation of Fracturing Methods for the Stimulation of Devonian Shale in Northern Ohio	Smith, E.C., Forrest, R.M., Morse, W.F.	Columbia Gas System Service Corp.	1982 Feb
	Evaluation of Sites of Intersections of Linear Features in Relation To Yileds of Gas and Water from Wells	O'Neil, C.E., Anderson, T.H.	Uninversity of Pittsburgh	1984 Aug
	Evaluation of Stimulation Technologies in the Eastern Gas Shales Project.	Young, Chapman	Science Applications, Inc.	1979 Oct
DOE/MC/19143-1305	Evaluation of the Devonian Shale Prospects in the Eastern United States	Struble, R.A.	USDOE	no date
	Extraction Technology Development in the EGSP	Komar, C.A.	DOE-METC	
MERC/SP-77/4	Field and Laboratory Procedures for Oriented Core Analysis of Devonian Shales.	Byrer, C.W., Komar, C.A.	MERC	1977 Aug
	Final Report of Special Geological, Geochemical, and Petrological Studies of the Devonian Shales in the Appalachian Basin.	Potter, Paul Edwin; Maynard, J. Barry; Pryor, Wayne A.		1980 Jan
	Final Report on Geochemical Studies in Eastern Kentucky.	deWys, Jane Negus		1981 Apr
	Final Report, Modeling of Devonian Shale Gas Reservoirs, Contract DE-AT21-78-MC08216, Task 16.		Science Applications, Inc.	1980 Jul
	Gas Production of Devonian Shale Wells Relative to Photo Lineament Locations: A Statistical Analysis.	Howard, J.F.; Lahoda, S.J.; Zirk, W.E.; Komar, C.A.	METC, METC/CR-79/28	1979 Apr

Report Number	Title	Authors	Organization	Date
	GeoChem reports for EGSP wells (multiple reports)		GeoChem Research Inc. for Mound Lab	1981
	Geochemical Evaluation of the Eastern Gas Shales-Part I.	McIver, Richard D.; Zielinski, Ronald E.		1978 Sep
DOE/METC/12142-26	Geologic & Geochemical Studies of the New Albany Shale Group (Devonian Mississippian) in Illinois.	Bergstrom, R.E., Shimp, N.F., Cluff, Robert		1980 Jun
019277-B	Geomorphology of Portions of Western Kentucky and Adjacent Areas (Topical Report)	Dilamarter, R.C.	Western Kentucky University, University of Michigan	1982 Jul
	Hydraulic Fracturing and Associated Stress Modeling for the Eastern Gas Shales Project (Final Report)	Advani, S.H.	Ohio State University	1980 Dec
	Hydraulic Fracturing Experiments in Devonian Shale and Pre-Fractured Hydrostone (Final Report)	Blanton, T.L.	Science Applications, Inc.	1981 Sep 30
	Importance and Control of Hydraulic Fracture Containment in Shale Well Stimulation	Young, C., Barbour, T.	Science Applications, Inc.	1979 May
	Inorganic Geochemistry of Devonian Shales in Southern West Virginia: Final Report.	Hohn, Michael Ed.; Neal, Donald W.; Renton, J.J.	WVGS	1980 Jun
DOE/METC/5199-7	Inorganic Geochemistry of Devonian Shales in Southern West Virginia: Geographic and Stratigraphic Trends.	Hohn, Michael Ed.; Neal, Donald W.; Renton, J.J.	WVGS	1980 Apr
	Integrated Program to Identify and Test Devonian Shale Prospect in Dually Completed Wells, Northern Appalachian Basin (Part I)	Tetra Tech, Inc.	Tetra Tech, Inc.	
	Integrated Study of the Devonian-Age Black Shales of Eastern Ohio.	Struble, Richard A.	OHGS	1979 Oct
	Interrelationships of Photolineaments, Geological Structures and Fracture Production of Natural Gas in the Appalachian Plateau of West Virginia.	Werner, Eberhard	West Virginia Univ., Dept of Geology and Geography	1977 Oct

Report Number	Title	Authors	Organization	Date
	Isolation of Kerogen from Eastern Gas Bearing Shale.	Leamey, Steven; Childers, Edward	METC	1978 Jul
MERC/TPR-77/2	Large Scale Foam Fracturing in the Devonian Shale-A Field Demonstration in West Virginia.	Frohne, K-H	MERC	1977 Apr
	Lineaments and Ground-Water Quality as Exploration Tools for Ground Water and Gas in the Cottageville Area of Western West Virginia.	Jones, D. Scott, Rauch, Henry W.	WVU Dept of Geol. & Geog.	1978
	Massive Hydraulic Fracturing Experiments of the Devonian Shale in Lincoln County, West Virginia.	Cremean, S. P.; Forrest, R. M.; McKetta, S.F.; Morse, M.F.; Owens, G.L.; Smith, E.C.	GSSC METC/CR-79/17	1979 Sep
	Material Properties of Devonian Shale for Stimulation Development	Blanton, T.L., Young, C., Patti, N.C.	Science Applications, Inc.	1980 Oct
	Mechanical Properties of Devonian Shales from the Appalachian Basin	Blanton, T.L., Young, C., Patti, N.C.	Science Applications, Inc.	1981 Sep
	Multizone Completion Opportunities in the Appalachian Basin (Final Report)	Koziar, G.	Columbia Gas System Service Corp.	1989 Mar
	Numerical Model Developments for Stimulation Technologies in the Eastern Gas Shales Project	Barbour, T.G., Maxwell, D.E., Young, C.	Science Applications, Inc.	1980 Jan
DOE/MC/08216-1333	Parameter Sensitivity Analysis of Tailored-Pulse Loading Stimulation of Devonian Gas Shale	Barbour, T.G., Mihalik, G.R.	Science Applications, Inc.	1980 Nov
	Physical and Chemical Characterization of Devonian Gas Shale.	Monsanto Research Facility	DE-AC04-76DP00053	
	Practical Aspects of Foam Fracturing in the Devonian Shale.	Komar, C.A.; Yost II, A.B.; Sinclair, A.R.	USDOE/METC Maurer Engineering SPE/AIME, SPE 3845	1979 Sep
	Prediction of In-Situ Stresses for Directional Properties of Rock Cores for Field Development of Devonian Shales.	Peng, Syd S., Okubo, Seisuke		1978 Jul

Report Number	Title	Authors	Organization	Date
	Price/Supply Study for the Eastern Gas Shales (Phase 1 Report)		Lewin and Associates, Inc.	1982 Sep
DOE/MC/08216-157	Quantitative Analysis of the Economically Recoverable Resource	Pulle, C.V. , Seskus, A. P.	Science Applications, Inc.	1981 May
DOE/MC/08387-1794	Re-Completion in the Devonian Shale (Final Report)		Mitchell Energy Corporation	1985 Mar
	Reservoir Model Analysis and Validation, 2-D Model with Induced Fracture Vol. 1 (Final Report)	Science Applications, Inc.	Science Applications, Inc.	1981 Jul 31
	Resource and Exploration Assessment of Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin	Zielinski, R.E., and McIver, R.D.	USDOE/METC	1982
	Review of OTA Assessment of Gas Potential from Devonian Shales	Cremean, S.P.	Columbia Gas System Service Corp.	1977 Aug 19
DOE/MC/12697-T1	Shale Gas in the Southern Central Area of New York State (Vol. 1)	NYSERDA	NYSERDA	1981 Sep
DOE/MC/12697-T2	Shale Gas in the Southern Central Area of New York State (Vol. 2) Experience of Locating and Drilling Four Shale-Gas Wells in NY	Donohue, D., Morrill, D.	Donohue Anstey and Morrill for NYSERDA	1981 Apr
DOE/MC/12697-T3	Shale Gas in the Southern Central Area of New York State (Vol. 3) Experience of Drilling Five Shale-Gas Wells in NY	Lynch, R.	Arlington Exploration Co.	1983 Mar
DOE/MC/14394-1365	Shallow Seismic Investigations of Devonian Shale Gas Production	Williams, R.T., Ruotsala, J.E., Kudla, J.J., Dunne, W.E.	West Virginia University	1982 Jun
	Some Results of EGSP of Interest to Illinois Basin Operators	Howard, J.F.; Lahoda, S.J.; Zirk, W.E.; Komar, C.A.	Howard and Assoc., Inc.	1978 Jun
DOE/ET/12041-1389(Vol.3)	Stimulation Research on Appalachian Tight Formations (Vol. 3, Appendix D. Final Report)	Columbia Gas System Service Corp.	Columbia Gas System Service Corp.	1980 May

Report Number	Title	Authors	Organization	Date
	Stimulation Research on Appalachian Tight Formations (Vol. I)	Cook, L.S., et al	Columbia Gas System Service Corp.	1980 May
	Stimulation Research on Appalachian Tight Formations (Vol. II, App. A,B,C))	Cook, L.S., et al	Columbia Gas System Service Corp.	1980 May
	Stimulation Technology Development in the Eastern Gas Shales Project (Progress Review)	Komar, C.A., Frohne, K-H, Yost, A.B.	DOE-METC	1978 Feb
DOE/ET/12138-1374	Strataspecific Geochemical Trend Maps for Eastern Kentucky	Negus-de Wys, J.	West Virginia University	1981 Jan
	Strategy for Stimulation Technology in The Devonian Shale.	Komar, C.A.	METC	1979 Oct
	Stratigraphic and Geographic Distribution of Core in Black Shale Sequence (Mississippian and Devonian) in Appalachian Basin.	Kepferle, Roy c., Potter, Paul Edwin	USGS and U. CIN	1978 Mar
	Stratigraphy and Sedimentology of Radioactive Devonian-Mississippian Shales of the Central Appalachian Basin.	Provo, Linda J.; Potter, Paul Edwin; Maynard, J. Barry; Cin, U.		1976 Dec
	Stratigraphy of the Chattanooga Shale in the Newman Ridge and Clinch Mountain Areas, Tennessee.	Milici, Robert C.; Roen, John B.	TNGS	1980 Oct
DOE/MC/16333-1448	Stress Trajectory and Advanced Hydraulic Fracture Simulations for the Eastern Gas Shales Project (Final Report)	Advani, S.H., Lee, J.K.	Ohio State University	1983 Jul
	Structural Geology of the Moorman Syncline Area of Western Kentucky (Topical Report)	Shumaker, R.C.	West Virginia University, University of Michigan	1982 Jul
	Studies of the New Albany Shale (Devonian and Mississippian) and Equivalent Strata in Indiana	Hasenmueller, N.R., Woodard, G.S.	Indian Geological Survey	1981 Sep
	Study of Hydrocarbon-Shale Interaction.	P. Schettler	Juniata College	

Report Number	Title	Authors	Organization	Date
MERC/CR-77/5	Subsurface Stratigraphy and Gas Production of the Devonian Shales in West Virginia.	Patchen, Douglas G.		1977 Mar
	SUGAR Ver. 3.00 Users Manual (Vol. III)	Science Applications, Inc.	Science Applications, Inc.	1981 Jul 31
	SUGAR-MD Ver. 2.00 Users Manual (Vol. II)	Science Applications, Inc.	Science Applications, Inc.	1981 Jul 31
	Technical Report, Chemical Explosive Fracturing, Devonian Shale Kentucky.	LaRocca, S.J., Spencer, A.M.	PTC	1977 Jul
DOE/MC/19239-1834	Technically Recoverable Devonian Shale Gas in Kentucky.	Kuuskraa, Sedwick, Thompson, Wicks	Lewin and Assoc.	1985
DOE/MC/19239-1525	Technically Recoverable Devonian Shale Gas in Ohio	Kuuskraa, V.A., and Wicks, D.E.	Lewin	1983 Jul
DOE/MC/19239-1750	Technically Recoverable Devonian Shale Gas in West Virginia	Kuuskraa, V.A.; Wicks, D.	Lewin	1984 Dec
	The Application of Core and Log Data to Determine Producible Hydrocarbon Intervals in the Devonian Shale.	Yost, A.B. II; Karl-Heinz Frohne, Komar, Charles A.; METC; Ameri, S.	WVU College of Engineering SPE/AIME, SPE 9271	1980 Oct
	The Concept of Specific Degasbility and its Application to the Gas-Bearing Tight Formations as Represented by the Devonian Shales of Appalachia.	Schettler, Paul D. Jr.	Juanita College	1979 Oct
	The Cottageville (Mount Alto) Gas Field, Jackson county, West Virginia: A Case Study of Devonian Shale Gas Production.	Nuckols, E.B. III	WVU Dept of Geol. & Geog.	1979 Dec
	The Occurrence of Oil and Gas in Devonian Shales and Equivalents in West Virginia.	Schietering, Joseph F.	WVGS	1981 Mar

Table 3.1.2: List of Core Reports Associated With EGSP Wells.

Well	Cliffs Minerals Reports			Mound Reports
	Phase 1 Rpt.	Phase 2 Rpt.	Phase 3 Rpt.	GeoChem
OH 1	NA	NA	X	X
2	NA	NA	X	
3	X	X	X	X
4	X	X	X	X (2 vol)
5	X	X	X	X (tables 9A-11)
6-1	X	X		X (tables 9A-11)
6-2	X	X		X (tables 9A-11)
6-3	X	X	X	X (tables 9A-11)
6-4	X	X		X (tables 9A-11)
6-5	X	X		X (tables 9A-11)
7	X	X	X	X (tables 8-11)
8	X	X	X	X (tables 4-11)
9	X	X	No Samples	X (tables 1-12)
10		X	No Samples	
IL 1	NA	NA	X	
2	NA	NA		
3	NA	NA		
4	NA	NA	No Samples	
5	X	NA	X	
IN 1	NA	NA	NA	
2	NA	NA	NA	
KY 1	NA	NA	X	
2	NA	NA		X
3	NA	NA	X	
4		X	X	X
5	NA	X	X	
MI 1	X	X	X	
2	X	X	X	
Dow Wells (3)	NA	X	X	
NY 1		X	X	X (2 vol)
3	X	X	X	X (tables 4-11)
4	X	X	X	X (tables 4-11)
PA 1	X	X	X	X
2	X	X	X	X
3	X	X	X	X (2 vol)
4	X	X	X	X (tables 7-11)
5	X	X	X	X (tables 7-11)
TN 9	X	X	X	X (tables 7-11)
WV 1	X			
2	NA	NA	X	
3	NA	NA	No Samples	
4	NA		X	
5	NA	X	X	X (2 vol)
6		X	X	X
7	X	X	X	X
VA 1	NA	NA	X	X*

** SAI not GeoChem, 2 volumes*
NA – not available
X – scanned and available on CD

Table 3.1.2: List of Logs Associated With EGSP Wells.

Well	Well Name	County	Log Date	Logs Scanned
OH 1	Glen-Gery 5-745	Carroll	Dec 74	Yes
2	F.L. House R-109	Washington	Jul-Aug 76	Yes
3	Louise Beckholt No. 2	Knox	Apr 79	Yes
4	EGSP/OH-4	Ashtabula	Jul-Aug 79	Yes
5	B&R McGuire 20149-T	Lorain	Sep 79	Yes
6-1	St. Carpenter I-5	Gallia		**No**
6-2	White Price Newberry Unit 1-7	Gallia	Oct 79	Yes
6-3	L. McCombs 1-6	Gallia	Oct 79	Yes
6-4	Straight-Wisemandle Unit 1-8	Gallia	Nov 79	Yes
6-5	M. Carter 1-9	Gallia	Nov-Dec 79	Yes
7	Meleski 20143T	Trumbull	Sep 1979	**No**
8	H.F. & M.M. Schockling No. 1	Noble	Mar 80	Yes
9	Gorrell-Coleman (OWTP)	Meigs	Feb 81	**No**
10		Meigs	Jul 82	**No**
IL 1	Lancaster 1-D	Effingham	Feb 77	Yes
2	MAK No. 1	Tazewell	Aug 77	Yes
3	RAR No. 1	Henderson	Jul 77	Yes
4	Missouri Portland No. 1	Hardin	Nov-Dec 78	Yes
5	Simpson No.1	Wayne	Oct 79	Yes
IN 1	Phegley Farms No. 1	Sullivan	Aug-Sep 76	Yes
2	Clark State Forest SDH-290	Clark	Aug 78	Yes
KY 1	N. Combs No. 7239	Perry	Jun-Jul 75	Yes
2	J. Ray Clark No. 1	Christian	Sep 76	Yes
3	CGT No. 20336 and 20337	Martin	Oct-Nov 76	Yes
4	Skaggs-Kelly Unit 3-RS	Johnson	Dec 78	Yes
5		Rowan	1982	**No**
MI 1	4-40 Club 1-35	Otsego	Jan 80	Yes
2	State Chester 18	Otsego	Sep 80	Yes
Dow Wells (3)	No. 100, 103, 205	Sanilac		**No**
NY 1	NFG 6213 (JO)	Allegheny	Sep 78	Yes
3	A.E. Scudder Unit No. 1	Steuben	Jul 80	Yes
4	Valley Vista View No. 1	Steuben	Jul 80	**No**
PA 1	Minard Run Expl. No. 1	McKean	Feb 79	Yes
2	C.E. No.1	Allegheny	Mar 79	**No**
3	Presque Isle State Park No. 1	Erie	Oct 79	Yes
4	Glen McCall No. 5	Indiana	Nov 79	Yes
5	Sokevitz No. 1	Lawrence	Dec 79	Yes
TN 9	GFI No.1	Grainger	Jan 80	**No**
WV 1	L.A. Baler No. 11940	Jackson	Jun 75	Yes
2	W.L. Pinnell No. 12041	Jackson	Nov 75	Yes
3	CGT No. 20403, 20401	Lincoln	Jan 76	Yes
4	CGT No. 20402	Lincoln	Mar 76	Yes
5	D-K Farm No. 3	Mason	Jan 78	Yes
6	MERC No. 1	Monongalia	Apr 78	Yes
7	H. Emch & A. Pyles Unit No. 1	Wetzel	Oct 78	Yes
VA 1	Penn Va. Farm No. 20338	Wise	May 77	Yes

3.2. Western Gas Sands Program (1978-1992)

By the late 1970s when the Western Gas Sands (WGS) R&D Program was initiated, tight gas in the Rocky Mountain Foreland basins was a poorly understood and largely uneconomic resource. The oil and gas E&P industry was skeptical toward the idea of significant widespread production from these discontinuous, low-permeability sandstones. A moderate volume of gas, estimated at about 1 Tcf per year in 1976, was being produced from the mature tight sandstone fields of the Appalachian, San Juan and Permian basins. This amounted to less than 6 percent of U.S. non-associated gas production and less than 5 percent of total gas production. In addition, the more geologically favorable ("near tight") portions of the Gulf Coast, East Texas, Mid-Continent and Williston basins were producing about 360 Bcf annually. However, the five main Rocky Mountain gas basins (Greater Green River, Wind River, Piceance, Uinta, and Denver) that would be selected as the focus of the DOE R&D program were producing only 162 Bcf per year from what was then a proved reserves base of only about 2 Tcf; less than 1 percent of the nation's proven dry gas reserves at the time.

The FY 1978 Congressional Budget Request explained the justification for initiating western gas sands R&D as part of a restructured program focusing on enhanced oil and gas recovery. However, while the FY 1978 Enhanced Gas Recovery (EGR) budget was 80 percent higher than the previous year, much of the increase was devoted to projects related to Eastern Gas Shales and Coalbed Methane. Western gas sands R&D benefited from all subsequent budget increases however, and grew almost 300 percent from 1978 through 1981.

From 1982 through 1992 large recommended decreases in unconventional gas R&D spending reflected the Administration position that the government should not be involved in resource development. Although Congress generally appropriated more than the Administration requested during this period, the WGS Program R&D budgets gradually declined. In 1993 the Administration reorganized DOE's budget structure towards a technology focus rather than a resource focus and the WGS Program essentially disappeared as a stand-alone program. R&D focused on naturally fractured tight reservoirs did continue, but on a more limited scale.

However, during its sixteen years the WGS Program made extremely important contributions to our fundamental understanding of how basin-centered gas accumulations occur and how these reservoirs can be effectively stimulated to produce gas at economic rates. The considerable progress that has been achieved over the past thirty years in developing technologies for finding and producing tight gas reservoirs owes a great deal to the basic knowledge that was developed under the WGS Program and the technology development process that it set in motion. In 2004, tight gas production (from all regions,

not just western basins) was just over 5 Tcf, more than 28 percent of U.S. non-associated gas production and more than 21 percent of total gas production. The DOE's Energy Information Administration (EIA) currently expects tight gas production from the Rocky Mountain basins to reach nearly 2.3 Tcf per year and overall tight gas production in the U.S. to reach nearly 5.5 Tcf per year by 2020, a testimony to the WGS Program's early recognition of the long term importance of this resource to the nation's energy supply.

3.2.1. Key Questions and Related R&D Goals

The WGS Program targeted "tight" (low permeability) sandstone reservoirs in Western basins. Such reservoirs are often defined as gas bearing sandstone (which may or may not contain natural fractures) which exhibits an *in situ* permeability to gas of less than 0.10 millidarcy (mD). Many "ultra tight" gas reservoirs may have *in situ* permeability as low as 0.001 mD. In addition to low permeability and porosity, these sands are often characterized by high water saturation and high clay content. At the time, even measuring these properties was a problem, as the recorded values could be highly sensitive to sampling procedures. Standard core analysis techniques were not precise enough and logging tools and interpretation techniques were not refined enough to provide accurate measurements.

The four major program elements and associated goals of the WGS Program were (Figure 3.2.1):

1. *Resource Determination* – The goal of this element was to reduce the uncertainty regarding the production and reserve potential of tight gas sands and direct priorities toward maximizing that potential.
2. *Resource and Site Characterization* – The goal of this element was to provide an accurate geologic understanding of specific local sites to guide the design of effective recovery technologies and thus improve overall resource estimates.
3. *Research, Instrumentation and Modeling* – The goal of this element was to develop the tools, procedures, measurements, concepts and models required to effectively recover gas from tight sands.
4. *Production Technology Development* – The goal here was to develop and test cost-effective means of recovering gas from Western U.S. tight sand formations.

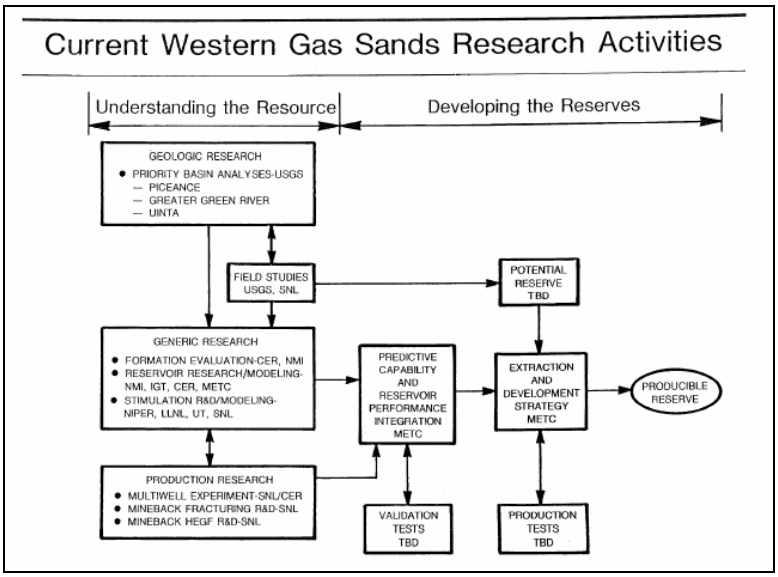

Figure 3.2.1: Schematic of WGS Program Research Plan.

The objectives associated with these goals were as follows:

Resource Determination:

- Generate information sufficient to adequately characterize the geology of the priority basins.
- Construct geologic models to facilitate the advancement of production technology research and instrumentation development.
- Identify and quantify the in-place gas resource and based on current economics and technology assess the recoverable resource.

Resource and Site Characterization:

- Develop geologic understanding of the nature, amount and distribution of gas in western tight gas sands.

Research, Instrumentation and Modeling:

- Improve the quality of geologic diagnostic data.
- Improve the understanding of geologic controls on tight gas production.
- Improve methods of predicting reservoir performance.
- Improve methods of predicting, measuring and applying in situ stress data.

- Improve the understanding of hydraulic fracture fluid mechanics and fracture propagation.

Production Technology Development:

- Apply and evaluate the application of hydraulic fracturing technology to tight gas reservoirs.
- Demonstrate the capability of fracturing to stimulate production from multiple sand lenses distant from the wellbore.
- Improve techniques for conducting multiple fractures from a single wellbore.
- Field test results of laboratory investigations into minimizing fracture fluid damage to the formation and proppant crushing.

Prior to 1977, the Department of Energy had looked at alternatives to hydraulic fracturing stimulation as a means for producing tight gas and determined that these were not viable. These alternatives included the nuclear explosion projects carried out under the Plowshare Program (the Rulison and Rio Blanco tests carried out in western Colorado in 1969 and 1973, and the Gasbuggy test carried out in northwestern New Mexico in 1967), as well as chemical explosive projects carried out in Texas reservoirs by DOE and the US Bureau of Mines during the same time period. Accordingly, the Production Technology Development portion of the WGS Program R&D focused on hydraulic fracturing.

The key contractors and R&D partners associated with these goals were as follows:

Resource Characterization:

- CER Corp. (core acquisition).
- CK GeoEnergy (out-crop studies).
- USGS (resource & reservoir characterization).

Research, Instrumentation and Modeling:

- Bartlesville Energy Technology Center-NIPER (fracture conductivity experiments, improved log interpretation).
- Sandia National Labs (Mine-back experiments, instrumentation development, logging tool development).
- Lawrence Livermore National Lab (models and instrumentation, *in situ* permeability measurement capability).
- Los Alamos National Lab (NMR log tool development).
- New Mexico Institute of Mining and Technology (rock property measurement).

- Institute of Gas Technology (*in situ* permeability measurement).
- Texas A&M University (improved log interpretation).
- University of Tulsa (proppant transport model).
- Terra Tek (proppant design R&D).

Production Technology Development:

- Sandia National Laboratories (implement MWX field test site).

3.2.2. Program Design and Overview of Major Projects

The Western Gas Sands (WGS) Program was directed toward the development of new and improved techniques for recovering gas from low-permeability (tight) gas reservoirs that (at that time) could not be economically produced. The purpose of the project was to encourage and supplement industrial efforts in developing technology and demonstrating the feasibility of economically producing natural gas from these reservoirs. The four main objectives of the program were to:

1. Accurately define the resource base,
2. Develop and implement techniques for determining physical and chemical properties of the reservoirs,
3. Determine appropriate stimulation technology, and
4. Combine these elements to assess potential gas reserves and demonstrate economic productivity.

The logical progression of the research plan is schematically illustrated in Figure 3.2.1. The first phase, Understanding the Resource, was divided up into Geologic Research, Generic Research and Production Research. Activities in Geologic Research included detailed, basin-wide definition to guide the eventual estimation of gas reserves. Generic Research focused on fundamental geoscience research on natural fractures, sedimetology and geomechanics related to tight sands. METC in-house research in this area centered on the analysis of production systems in low-permeability, fractured reservoirs. Production Research encompassed field research activities: the multiwell site (MWX), drilling and coring of a slant-hole, and mineback experiments.

In the second phase, the results of the Generic and Production Research were combined by METC to enhance the ability to predict tight gas sand reservoir performance, which in turn was used to guide field development and production strategy. These strategies, when applied to the estimates of potential reserves produced by the Geologic Research element of the program, resulted in the ultimate product of the WGS Program, more reliable estimates of producible gas reserves.

The WGS Program included more than a dozen individual research projects spread over the 1977 through 1992 time frame. The most significant of these projects, listed in rough chronological order, are briefly outlined below along with several related projects that either pre-dated or continued efforts initiated by the WGS Program.

Single-Well Test Program

The Single Well Test Program predated the Department of Energy and the WGS Program. Begun in 1974 and continued through 1981, this program involved government/industry cost-shared programs to evaluate Massive Hydraulic Fracture stimulation of various tight-gas reservoirs. These stimulations had been somewhat effective in blanket reservoirs, but poor results were typical in lenticular reservoirs. However, the reasons for these poor results (e.g., poor log evaluation, ineffective stimulation sizes, damaged reservoirs, very small lenses, etc.) were not understood. The results of these tests provided part of the rationale for the subsequent Multiwell Experiment (MWX) testing program that was an important part of the WGS Program. A total of 13 wells were stimulated in 4 basins under the Single-Well Test Program. Roughly half of the fracturing operations resulted in a significant increase in gas production.

Coring Program

The Coring Program was started in 1978 with the objective of providing rock samples from various western basins for study and testing by various laboratories, the USGS, and industry partners. At the time this program was initiated, there was very little information on the low permeability reservoir rocks that comprised “tight gas sand” formations. Studies were carried out that included mineralogy, petrology, reservoir properties and mechanical properties of these reservoir rocks. These tests provided samples for laboratory work to explore issues associated with clays, acidization, permeability damage from drilling and fracturing fluids, fluid compatibility, proppant embedment and many other factors, and helped provide the basic data needed to evaluate subsequent stimulation and production tests. A total of 2,980 feet of core was taken from 12 wells in 4 basins between 1978 and 1981. Core material was distributed to the USGS, Sandia National Labs, Institute of Gas Technology and Texas A&M University for analysis. The coring and logging activities were coordinated with the Gas Research Institute.

The Multiwell Experiment (MWX)

The Multiwell Experiment (MWX), conducted from 1981to 1988, was a field laboratory established in the Piceance basin in western Colorado. The MWX was aimed at the dual objective of: 1) improving the ability to characterize tight sands reservoirs and 2) improving the ability to fracture stimulate (and thereby enhance production from) these reservoirs. All prior tight gas sands experiments had been conducted at well spacings of

640 or 320 acres (roughly 5300 to 3700 feet between wells). This meant that the wells were too widely spaced to permit proper evaluation of the continuity in these lenticular reservoirs or to assess production/stimulation characteristics through interference testing or via various crosswell monitoring and evaluation technologies (e.g., downhole fracture diagnostics, crosswell seismic, etc.). The MWX experiment was designed to provide a closely spaced three-well pattern (110 to 215 feet between well bores) to provide for the effective evaluation of the reservoirs and assessment of hydraulic fracture growth, and ultimately, to the understanding of tight gas sand production mechanisms.

Key features of the MWX program were the coring, logging, testing and fracturing programs conducted during the eight years of site operation. Over 4,000 ft of core were obtained during the drilling of the three wells and nearly 1,000 ft of that core was oriented. Approximately 60 ft of pressure core were also obtained in order to accurately compare core and well log water saturations. In addition to reservoir properties, the core samples provided samples for all other testing programs at the MWX site. Very importantly, the core analysis that was carried out emphasized not only the pay zones themselves but the abutting formations as well. The core samples and fracture logs, in particular the oriented core and televiewer data, allowed for a unique evaluation of the *in situ* natural fracture system and the geologic/tectonic factors that produced the fractures (including the mechanism for the formation of regional fracture systems that are common in western tight gas basins). The well testing program in conjunction with the core reservoir properties and natural fracture data defined for the first time the true nature of tight gas sand reservoirs in the western US basins.

An attempt was made at MWX to run every log available at the time (including experimental logs such as Mobil's televiewer, Amoco's and Schlumberger's long-spaced sonic logs, and Schlumberger's dipmeter). One of the very first crosswell tomogram surveys, performed at the MWX site, illustrated the degree of reservoir continuity between the wells.

The stress testing program at MWX was undoubtedly the most comprehensive stress test program ever completed in an oil and gas reservoir, including 63 microfrac measurements, anelastic strain recovery, differential strain curve analysis, circumferential velocity anisotropy, wellbore breakouts, coring induced fractures, basinal calculations, tectonic assessments, and fracture diagnostics for stress azimuths. This study provided the first comprehensive comparison of these techniques and assessment of their accuracy and reliability.

Hydraulic fracture experiments conducted in six intervals highlighted the factors critical to successful stimulation of these reservoirs. The importance of liquid-induced damage to the natural fracture system was shown through careful pre- and post-fracture testing,

lab testing, and fluid research performed specifically for these experiments. The first successful microseismic monitoring tests in tight gas reservoirs were conducted at MWX and showed that fractures grew out-of-zone in a manner proportional to the stress contrasts and that actual fracture lengths were considerably shorter than designed.

Slant Hole Completion Test (SHCT)

The Slant Hole Completion Test (SHCT), conducted from 1990-1993, was a follow on test at the MWX site to exploit the findings about the importance of the natural fracture systems in tight gas sands by using directional drilling to intercept large numbers of fractures. Although considerable difficulty was encountered in attempting to drill into highly overpressured natural fracture systems, the well was successful in showing that the productivity of a directionally drill well bore in one zone (the Cozzette sandstone) was 10-20 times that of a vertical well completed in the same zone. Very importantly, core was taken in two deviated well bore intervals (through both lenticular sands and a blanket marine sand) and a number of important findings resulted from the core analysis carried out on these cores.

Multi-Site Experiment (M-Site)

The Multi-Site Experiment (M-Site) was also conducted at the MWX location, but its focus was specifically on the further development of hydraulic fracturing technology. The M-Site project was a joint effort funded by both DOE and the Gas Research Institute (GRI, now the Gas Technology Institute or GTI). Conducted from 1994 to 1996, after the WGS Program had been curtailed, the objective of this project was to construct a field laboratory that could be used to further develop and validate hydraulic fracture diagnostic technology, assess hydraulic fracturing mechanisms, and improve hydraulic fracturing stimulation models through a more complete physical understanding of the process. The M-Site testing used two of the MWX wells for injection and monitoring purposes, one newly drilled well for cemented-in-place microseismic and tiltmeter arrays, and two new deviated lateral wells to intercept the fractures, confirm the diagnostics, and directly interrogate the created fractures through flow testing or pressure monitoring. Comprehensive sets of fracturing experiments were conducted in two intervals (along with a preliminary set of tests in a third interval) in fluvial reservoirs that had been extensively characterized as a result of previous MWX work.

Mineback Stimulation Experiments

The actual shape and character of well bore fractures created by hydraulic stimulation were poorly understood in the late 1970's because created fractures and the effects of stress contrasts, layered formations, faults, natural fractures and other features of reservoir heterogeneity had never been observed *in situ*. The mineback stimulation experiments conducted in a tunnel at a Nevada Test Site early in the WGS Program

provided the first direct evidence of fracture behavior *in situ* by creating subsurface hydraulic fractures near a tunnel and then mining back to intersect them.

Hydraulic fracturing experiments were conducted adjacent to an existing tunnel complex at DOE's Nevada Test Site and the results were directly observed by subsequent mineback through the experimental area. A proppant distribution fracture experiment revealed a very complex fracture system. Observed fracture lengths were only 5 and 25 ft at the depth of the fracture interval; a significant difference from the design lengths of 175 ft. The fracture interacted with numerous geologic faults, fractures, and bedding and parting planes. Variations of the *in situ* stresses and orientations that were found in subsequent testing in this experiment region were determined to be contributing factors. An experiment was also designed and conducted which examined the behavior of hydraulic fractures at an interface between an ashfall tuff formation and a welded tuff formation. These formations have significant differences in their elastic moduli, Poisson's ratios and porosities. However, these differences were found to have no apparent effect on containment, with fracture growth being predominantly vertical. The experiment showed that actual hydraulic fractures were not consistent with expected results based on design models: formations of higher modulus do not contain hydraulic fractures, in situ stresses do; fracture geometry is not rectangular and symmetric; and proppants are not placed in a prescribed manner.

Western Gas Sands Associated R&D

In conjunction with the field testing program, a number of associated research activities were conducted to support the development of improved characterization and extraction technology. These activities included tool development, modeling, and laboratory studies. Significant effort was expended in developing hydraulic fracture diagnostic technology that could accurately map the fractures created by hydraulic stimulation. Starting in 1979, the USGS and subsequently, M. D. Wood & Associates, were funded to develop surface tiltmeter technology for fracture mapping. Sandia National Labs developed the Surface Electrical Potential technique and various borehole diagnostic tools (hydrophone strings and tri-axial geophone receivers) for mapping fractures.

Logging technology was studied at several laboratories in attempts to either improve the accuracy of existing logs in tight reservoirs or to develop new ones. Work included: 1) studies of tight gas sand water resistivity at Texas A&M University, 2) studies of the nuclear magnetic resonance (NMR) properties of tight gas sand rocks and the development of NMR instruments at Las Alamos National Labs, and 3) the modeling and measurement of the dielectric properties of tight reservoir rocks at Sandia National Labs.

Drilling technology that improved the efficiency of drilling through hard rocks was advanced by breakthroughs in polycrystalline diamond compact (PDC) bits at Sandia

National Labs. The PDC bit has proven to be fast and rugged in many of the rock types encountered in western U.S. basins and continues to be widely used today. In addition, the Bartlesville Energy Technology Center and Sandia National Labs worked with industry to develop pressure-coring capabilities (including PDC core bits) and non-invasive fluids that could be used with pressure core equipment.

The Bartlesville Energy Technology Center, New Mexico Tech and the Institute of Gas Technology developed a number of core analysis techniques designed specifically for tight gas sands, including ways to measure: cation exchange capacity, porosity, pore-volume compressibility, Klinkenberg corrected permeability, effects of stress and water saturation on permeability, capillary pressure, and caprock threshold pressures. Sandia National Laboratories developed techniques for measuring the effective stress law parameters for tight rocks.

Resource Assessment Projects

Reviews of the nation's marginal gas resource base during the mid-1970s to mid-1980s pointed to the possibility that huge natural gas resource volumes existed in Western basins (Figure 3.2.2). Estimates of the gas resources of the Greater Green River basin of Wyoming, for instance, ranged from 90 to 240 Tcf of gas-in-place. However, the studies behind these estimates incorporated several features that suggested they might be significantly under-estimating the resource. First, they had routinely dismissed gas below certain threshold depths, typically 13,000 to 15,000 feet. Second, they had focused only on specific formations (particularly those that had provided significant conventional production elsewhere), thereby ignoring large rock volumes. To arrive at a more complete assessment, the USGS and DOE began work to comprehensively assess the resources present in major western U.S. basins (Figure 3.2.2). This work was conducted independently from the USGS's regular national assessments, which focused only on the volumes thought to be technically recoverable.

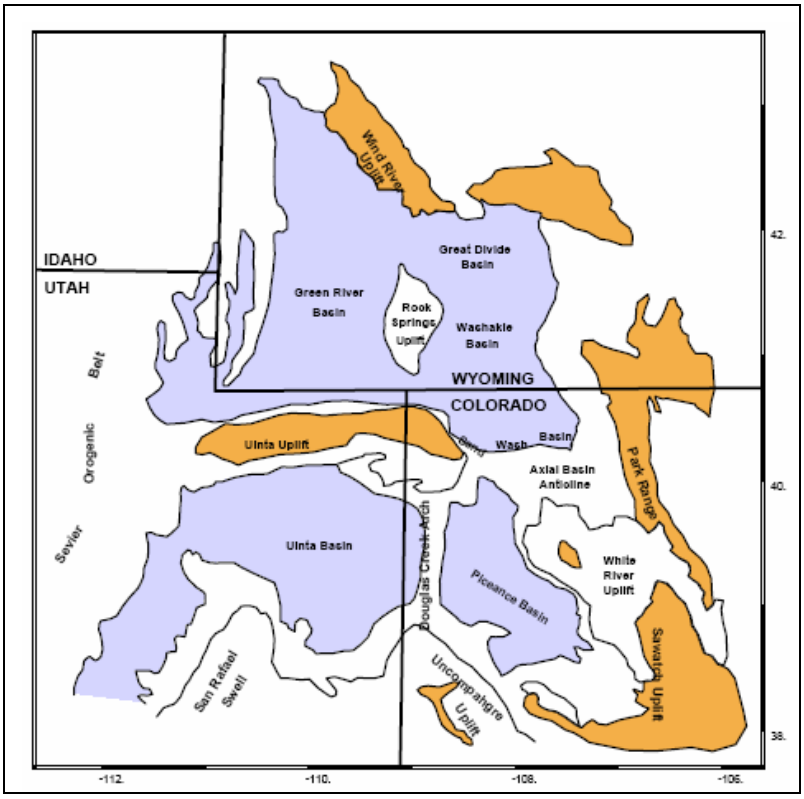

Figure 3.2.2: Location of Major Western Gas Basins.

Five detailed gas-in-place studies were conducted during the course of the WGS Program and after: Piceance basin (1987); Greater Green River basin (1989); Bighorn basin (1990); Uinta basin (1990); and Wind River basin (1996). The results of these studies, and in particular the estimate that more than 5,000 Tcf of gas-in-place existed in the Greater Green River basin alone, were shockingly large to those in the industry who had relied on the highly-restricted gas-in-place and technically-recoverable-only estimates of earlier workers. Nonetheless, time has shown that these values are not only realistic, but perhaps may even have still underestimated the existing resource.

Recoverable Resource Assessment Projects

Following the release of the first two USGS in-place studies, DOE contracted with the Scotia Group to re-assess the estimates of total tight gas-in-place in selected western basins and to estimate how much of that gas should be recoverable under current cost and technology conditions. This reassessment was deemed necessary given perceived skepticism over the large volumes presented by the USGS (particularly the 5,000 Tcf Greater Green River basin figure). The earlier USGS numbers were indeed revised downward by Scotia, primarily as the result of the claim that the USGS methodology

possibly over-estimated typical porosities and understated typical water-saturations in all the basins. In total, Scotia estimated 3,165 Tcf of gas in place for the Greater Green River, Uinta, Piceance, and Wind River basins.

3.2.3. Key Western Gas Sands Projects

Listed below are the key Western Gas Sands projects undertaken during the 1977-1992 time frame. The primary Project Manager for the Western Gas Sands program during this time period was Karl-Heinz Frohne.

Geotechnology for Low-Permeability Gas Reservoirs
Contract: DE-AC04-76DP00789 (FEW-2086)
Performer: Sandia National Labs
Key Investigators: D.A. Northrop, N.R. Warpinski, R.A. Schmidt, J. C. Lorenz, A.R. Sattler, L.R. Phillips, L.W. Teufel
Time Period: 1976 –1992+
Objectives: The broad objectives of this project were to develop an understanding of the geotechnology associated with production of gas from tight, naturally-fractured, lenticular reservoirs of the western U.S., and specifically to:

- Characterize the natural fracture systems,
- Determine the relationship between the natural fractures and the in situ stresses and depositional environment,
- Evaluate the interaction between stimulations and natural fracture systems,
- Develop models of the origins of natural fracture systems in western basins, and
- Analyze unique and important rock/reservoir characteristics of these reservoirs.

This contract included work related to the Mineback Experiment carried out at the Nevada Test Site in 1977-78.

Geologic Characterization of Tight Gas Reservoirs (Greater Green River Basin and Piceance Basin)
Contract: DE-AI21-83MC20422
Performer: U.S. Geological Survey (Denver, CO)
Key Investigators: B.E. Law, C.W. Spencer, M.R. Lickus, W.W. Dickenson, R.M. Pollastro, C. W. Keighin, R.C. Johnson, V.F. Nuccio, J.K. Pitman
Time Period: 1983 – 1992
Objectives: The main objective of this project was to conduct geologic research on GGRB low-permeability gas reservoirs in order to gain an improved understanding of the nature of these unconventional gas accumulations.

Characterization of Tertiary and Cretaceous Low-Permeability Gas Bearing Rocks in the Uinta Basin, Utah
Contract: DE-AI21-83MC20422-1
Performer: U.S. Geological Survey (Denver, CO)
Key Investigators: T.D. Fouch, J.K. Pitman, J.W. Schmoker, G.L. Dolton, C.J. Wandrey, V.F. Nuccio, D.D. Rice, J.B. Wesley
Time Period: 1989 – 1990
Objective: The objective of this project was to characterize reservoir units and assess the gas resources in the Uinta Basin's tight siliciclastic reservoirs.

Rock Matrix and Fracture Analysis of Flow in Western Tight Gas Sands
Contract: DE-AC21-84MC21179
Performer: New Mexico Institute of Mining and Technology (Petroleum Recovery Research Center), Socorro, NM
Key Investigators: J.J. Taber, N.R. Morrow, J.S. Buckley, M. Cather, K.R. Brower, Xiaoyun Zhang, B. Gonzales, M.L. Graham, Shouxiang Ma
Time Period: 1984 –1989
Objective: To conduct research on measurement of rock matrix and fracture parameters in western gas sands, with the goal of obtaining reliable measurements of matrix and fracture properties through laboratory core analysis. The study was mainly concerned with the dependence of flow in tight gas sands on water saturation and confining pressure.

Laboratory Research on Fracturing Materials for the DOE/MWX
Contract: DE-FC01-83FE60149 and Sandia Contract No. 95-4340
Performer: IIT Research Institute, National Institute for Petroleum and Energy Research (NIPER)
Key Investigators: C. Raible, B. Gall, D. Maloney
Time Period: 1983 –1992
Objectives: The objective of this project was to identify where fracturing materials may cause gas production limitations:

- Formation and natural fracture damage from fracturing fluids,
- Polymer molecular weight effects aimed at relating polymer degradation to propped fracture flow restriction, and
- Proppant testing to evaluate proppant strength and embedment.

LLNL Unconventional Gas/Western Sands Research (WGS Subprogram)
Contract: W-7405-ENG-48
Performer: Lawrence Livermore National Laboratory (Livermore, CA)
Key Investigators: F.E. Heuze, W. Lin, R.J. Shaffer, R.B. Stout, A.M. Wijesinghe, R. Thorpe
Time Period: 1985 – 1992
Objectives: The objective of this project was to improve the understanding of the stimulation mechanics of lenticular and jointed tight gas reservoirs. Particular emphasis was put on the interaction of induced fractures with natural fractures, and on the determination of relevant rock mass properties for input into hydrofracture simulators.

Stimulation Model for Lenticular Sands
Contract: DE-AC21-84MC21119
Performer: University of Tulsa (Tulsa, OK)
Key Investigators: E.F. Rybicki, Ian Palmer (NIPER), J.S. Sutrick, C.T. Luiskutty and L. Tomutsa (Oral Roberts U.)
Time Period: June 1984 – June 1987
Objectives: The objective of this project was to:

- Develop a computational model to represent hydraulic fracturing and proppant transport for lenticular sands, and
- Apply this model to the muli-well experimental fracture stimulations

Crosswell Acoustic Imaging Project
Contract: AB-05-10-10-0
Performer: Los Alamos National Laboratory (Los Alamos, NM)
Key Investigators: J. N. Albright, P.A. Johnson, W. Scott Phillips
Time Period: 1985
Objectives: The objective of this project was to provide information about the structure and properties of coastal zone rock formations between the MWX wells through the development, validation and application of crosswell acoustic methodology.

Two-Phase Flow in Tight Sands
Contract: DE-FG21-85MC22000
Performer: Institute of Gas Technology
Key Investigators: Prasan Chowdiah
Time Period: 1985 –1987
Objectives: The objective of this project was to develop equipment as well as laboratory and analytical techniques for obtaining properties of tight sands that are needed for two-phase computer simulation of production.

Development of Core Analysis Procedures Using X-Ray Computerized Tomography
Contract: DE-FC21-87MC24156
Performer: TerraTek (Salt Lake City, UT)
Key Investigators: J.C. Sharer
Time Period: 1987 – 1989
Objectives: The objective of this project was to develop procedures and analytical capabilities to evaluate core using x-ray computerized tomography. Specific analyses to be developed included: matrix porosity, fracture porosity, effects of stress on fractures, and two phase steady state relative permeabilities.

Application of Stratified Random Sampling to Estimating Gas Reserves
Contract: DE-AC21-85MC21353
Performer: EG&G Washington Analytical Services Center, Inc.
Key Investigators: A. Smith, J. Hancock, M. Portman, R. Lopez
Time Period: 1988 – 1989
Objectives: The objective of this project was to assess the usefulness of stratified random sampling in estimating reservoir parameters and to verify the porosity, net pay thickness, gas saturated pore space, and resulting gas-in-place estimates made by the National petroleum Council (NPC, 1980) for the Dakota Formation in an area of the San Juan Basin.

Extrapolation of MWX Data into the Piceance Basin, CO
Contract: DE-AC21-88MC24120
Performer: CER Corporation (Las Vegas, NV)
Key Investigators: R. E. Hill, G.C. Kukal, P. Branagan, M. Wei
Time Period: April 1988 – November 1991
Objectives: The objectives of this project were to:

- Advance the technology developed at MWX into other areas of the Piceance Basin and verify the extrapolation potential of the geological and engineering findings and techniques;
- Reliably identify and characterize potential areas for Mesaverde gas resource development; and
- Develop an optimal methodology for developing this resource.

Slant Hole Completion Test: Mesaverde Group, Piceance Basin, CO
Contract: DE-AC21-90MC26024
Performer: CER Corporation (Las Vegas, NV)
Key Investigators: F. R. Myal, G.C. Kukal, R. E. Hill
Time Period: January 1990 – September 1990

Objectives: The objectives of this project were to evaluate directional drilling as an alternative development strategy for the tight, naturally fractured sands and coals in the Mesaverde Group in the Piceance Basin.

Reserves in Western Basins
Contract: DE-AC21-91MC28130
Performer: The Scotia Group (Dallas, TX)
Key Investigators: R. H. Caldwell, B.W. Cotton
Time Period: October 1991 – September 1995
Objectives: The objective of this project was to investigate the reserves potential of tight gas reservoirs in three Rocky Mountain basins: the Greater Green River (GGRB), Uinta and Piceance basins, including the subdivision of the resource based upon economic and technological considerations, into grouping that have distinct properties with regard to potential for future producibility, economics and risk profile.

Slant Hole Completion Test: Mesaverde Group, Piceance Basin, CO
Contract: DE-AC21-90MC26024
Performer: CER Corporation (Las Vegas, NV)
Key Investigators: F. R. Myal, G.C. Kukal, R. E. Hill
Time Period: January 1990 – September 1990
Objectives: The objectives of this project were to evaluate directional drilling as an alternative development strategy for the tight, naturally fractured sands and coals in the Mesaverde Group in the Piceance Basin.

Fracturing Fluid Characterization Facility
Contract: DE-FC21-92MC29077
Performer: The University of Oklahoma (Norman, OK)
Key Investigators: H. Cho, N. Goel, S. Khade, M. Mefford, A. Raichukar, N. Saddiq, S. Shah, Y. Zhou
Time Period: 1992 – 2000
Objectives: The objective of this project was to establish an experimental facility to provide accurate prediction of the behavior of complex fracturing fluids under downhole conditions, thus providing insight into the mechanisms that govern flow of fracturing fluids and slurries through hydraulically created fractures.

3.2.4. Highlights of Important Results

The Western Gas Sands Program was designed to accelerate the production of domestic gas resources. It was directed specifically at the development of new and improved techniques for recovering gas from low-permeability gas reservoirs in western basins that at the time of initiation of the program could not be economically produced. The purpose

of the program was to encourage and supplement industry efforts to develop technology and demonstrate the feasibility of producing from tight reservoirs.

The key contributions resulting from the WGS Program include:

- Collection and analysis of core material from a variety of location to provide data on the fundamental reservoir properties of tight sandstones that had previously been lacking,
- Development of new equipment and procedures for measuring tight sandstone rock properties,
- Detailed characterization of the geology and tight sand gas resource potential of five Rocky Mountain basins, that provided a basis for subsequent decision-making related to both R&D and resource development investments,
- Creation of an extremely well-characterized reservoir laboratory at the MWX site, that allowed for experiments that contributed critical insights towards answering questions related to the continuity of tight sands, the importance of natural fracture systems, the importance of in situ stress to hydraulic fracture design, and the size and shape of created hydraulic fractures compared to their design dimensions, and
- Development of geologic and production predictive models that enhanced efforts to find and economically produce natural gas from tight gas sands.

Specific products related to particular projects are listed below.

The Multiwell Experiment (MWX)

- Advanced Tight Gas Core Analysis Technology. Specialized equipment and techniques were developed at IGT, Core Labs, and New Mexico Tech to fully characterize the reservoir properties of very low permeability rocks. Of particular importance were methods that were developed to test rocks under both *in situ* stress and water saturation conditions and capillary pressure measurements to aid in the understanding of the important two-phase flow mechanisms (water and gas). These techniques are now routinely used for low-permeability core testing and are available commercially.

- Reservoir Characterization Methodology. The core samples in the three closely spaced wells, along with the careful assessment of numerous surface outcrops of these same reservoir rocks, provided the information necessary to develop methods for quantifying the size of sandstone lenses in various depositional environments. This methodology, which is now used by numerous companies working in the tight-sand basins, provides critical information needed for resource assessment, reserves calculations, fracture design, and well spacing in these fields.

- Naturally Fractured Core Analysis. A process for analyzing fractured core has been transferred to numerous companies and is routinely used by industry and techniques for identification of coring induced fractures is widely used. Information from stress sensitivity testing of naturally fractured cores is now used in many reservoir and fracture models.

- Stress Testing and Applications. MWX was the site where a methodology for micro-fracture stress testing through perforations using down-hole shut-in was fully developed and where anelastic strain recovery and circumferential velocity anisotropy were validated. Micro-fracture stress testing is a testing procedure now used routinely by companies throughout the world and anelastic strain recovery is a commercial service available through Halliburton. Altered stress fields due to fractures and other down-hole processes are now calculated and considered in many applications such as re-fracturing and in-fill drilling. The mechanism defined for the formation of regional fractures is being applied towards exploration strategies in many basins.

- Advanced Tight Gas Log Analysis. By running multiple logging suites (including experimental logs such as Mobil's televiewer, Amoco's and Schlumberger's long-spaced sonic logs, and Schlumberger's dipmeter), and coupling the results with the results of core analysis, new correlations were developed that more accurately predicted reservoir properties. The data was made available to all of the commercial logging companies.

- Extreme Overbalanced Perforating. While attempting to develop methods for effectively connecting to and testing the reservoir, the first extreme overbalanced perforation operations were conceived and performed at MWX. Extreme Overbalanced Perforating is a service performed by Halliburton and used routinely.

- Deviated or Horizontal Drilling in Fractured Reservoirs. The Slant Hole Completion Test resulted in a number of recommendations for using deviated well bores to exploit fractured reservoirs. This approach is now widely applied throughout the U.S.

While not strictly part of the 1977-1992 WGS Program, the Multi-Site Experiment (M-Site) that followed on the heels of the MWX work resulted in a number of important contributions:

- The first successful micro-seismic monitoring tests in tight gas reservoirs were conducted at MWX and showed that fractures grew out of zone proportional to the stress contrasts and that fracture lengths were considerably shorter than designed. The M-Site testing validated the accuracy of down-hole micro-seismic monitoring for

real-time mapping of hydraulic fracture growth and established the accuracy of the technique, the interpretation of the data, and the technology needed to acquire and process the data. Micro-seismic monitoring is now considered the most accurate method of imaging fracture growth and is now a globally-available commercial service.

- Downhole tiltmeters were first used for fracture monitoring during these tests and this technology is now a commercial service (Pinnacle Technologies) available to map fracture height and length.
- Important insights into the mechanisms of fracturing were developed at M-Site and are now being used in fracture models. Some of these are the development of multi-stranded fracture systems as a routine part of fracturing, the identification of additional fracture height containment in highly layered reservoir systems, the measurement of a large fluid lag region around the fracture tip, the formation of secondary and T-shaped fractures, and the variability in fracture development with different fluid systems.

Mineback Stimulation Experiments

- The Mineback Experiments at the Nevada Test Site provided the first observational evidence of fracture behavior *in situ*. These tests showed that *in situ* stress contrasts were the primary feature controlling fracture height growth, that modulus contrasts had little effect on height growth, that natural fractures caused considerable offsetting and branching of fractures, and that stress changes across faults and interfaces could stop fractures.

Western Gas Sands Associated R&D

- Significant effort expended in developing hydraulic fracture diagnostic technology that could map the created fractures helped to advance surface tiltmeter technology for fracture mapping. Surface tiltmeters are currently used for monitoring fractures as part of a successful commercial service (Pinnacle Technologies).
- Drilling technology was advanced by breakthroughs in PDC bits through work done at Sandia National Labs. This bit has proven to be fast and rugged in many of the rock types in western gas sands basins and PDC bits are commonly used throughout the industry.

Resource Assessment Projects

- The program in resource assessment provided the first comprehensive scientific quantification and characterization of a vast new resource, removing any question that pursuing the difficult technical challenges of enabling large-scale tight gas production

was clearly worthwhile, both for industry and government. Second, in tandem with the other efforts in the WGS Program, it highlighted the concept and importance of basin-center gas formations, providing a rationale for the unique off-structure exploration and development techniques that would enable production from overpressured, low-permeability reservoirs. As a result of this work, industry began not only to appreciate the volumes of gas present, but could also begin to see a way in which it could be produced. As a result, tight gas began to be widely recognized as a key part of the nation's resource base. Most notably, the USGS, which had previously excluded tight gas in their national resource assessment, included the category for the first time in 1995. Key outcomes of the effort include:

- Industry now knows how the resource is distributed in each basin, and which plays hold the most potential.
- Industry has more information on the typical porosities, water saturations, temperatures, and pressures of the rocks containing the resources.
- Industry now understands the unique qualities of basin-centered, or "continuous" deposits, and recognizes the need for new perspectives on appraisal methods tailored for conventional resources.

DOE expenditures in the Western Tight Gas Sands program from 1978 through 1992 amounted to about $95 million. From 1983 to 1988, most of the budget was used to fund basic research and sample analysis through the national laboratories. When the project emphasis changed from basic research to applied research in 1989, more funds were directed to actual procurements with private research companies and industry.

By the late 1980s, most of the research money was being spent in actual field demonstration projects. After 1992, research focused on tight gas sands became more product-oriented and a larger percentage of funding came from industry. In the basic and applied stages of the program, DOE expenditures led industry by 2 to l; in the demonstration stage, industry led DOE by nearly 3 to l.

According to the National Academy of Sciences report, *"Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000"* published in 2001, the Western Gas Sands program was successful in its goal of increasing the supply of natural gas at lower cost. Tight gas production from the Rocky Mountain gas basins was only 162 Bcf in 1978 at the start of the program; 10 years later it stood at 224 Bcf and in 2000 (when the NAS report was written) production was estimated at 700 Bcf, a fourfold increase. Since the report was written, Rocky Mountain tight sand gas production has grown even more; 2004 production from the five targeted basins was 1433 Bcf, nearly nine times the rate at the start of the WGS Program.

The NAS report determined that the WGS Program "has significantly advanced understanding of complex, lenticular reservoirs and how fracturing is deployed in them. A much larger part of the vast in-place resource in the basin-centered gas formations of the Rocky Mountain basins is now considered economically accessible."

In relating the costs and benefits of the WGS Program, the NAS credited the Program with developing technology and stimulating 35 percent of the tight gas produced from the Rockies from 1978 to 2005. The remaining 65 percent was assigned to industry's activity, GRI's R&D program (partially supported by DOE), and the influence of Section 29 tax credits for unconventional gas production. In calculating the benefits, the NAS included DOE R&D expenditures post-1992 (after the WGS Program had evolved into a more product-oriented R&D program) and estimated 2005 production from western tight gas sands at 800 Bcf (less than half of what was achieved). Even still, the NAS calculated a benefit to cost ratio of 8.9, and a contribution of $591 million (1999 dollars) from royalties on federal lands and from increased state severance taxes due to displacement of imports.

Further, the NAS report states that *"Future application of tight gas sand technology in emerging plays and basins will substantially enlarge this part of the resource base … providing an environmentally clean fuel and greater domestic supply. The application of resource assessments, natural fracture detection and prediction technology, and advanced drilling and stimulation, means that less than half as many wells will need to be drilled to yield the same volume of reserves."*

A significant part of the success of the WGS program was its successful transition from a basic research program supported entirely by government to an applied research and demonstration program in which industry took over increasing support of the program. Coupled with governmental tax credit incentives under Section 29 of the Natural Gas Policy Act, this targeted research program brought an important source of natural gas into the national supply stream earlier and cheaper than it would otherwise have been made available.

Because of the substantial base of knowledge and technologies developed under the WGS Program, the Energy Information Administration (EIA) has been able to make predictions of strong future tight gas production. The EIA calls for tight gas production from the Rocky Mountain basins to reach nearly 2,300 Bcf and overall tight gas production in the U.S. to reach nearly 5,500 Bcf in 2020.

3.2.5. Subsequent Developments in DOE Research Related to Tight Gas Sands

Although the WGS Program as a stand-alone program disappeared after 1992, several R&D efforts carried forward work that had begun under the WGS project. These were funded by DOE through GRI or as part of a reservoir diagnostics technology development program under the new organization. Descriptions of these efforts are included here for completeness.

Fracture Fluid Characterization Facility

In order to quantify the behavior of fracturing fluids and fluid/proppant slurries in the wellbore and in the fracture, during and after the hydraulic fracturing process, DOE co-funded along with GRI the Fracture Fluid Characterization Facility at the University of Oklahoma from 1992 through 2000. A unique above ground fracture simulator (the "High Pressure Simulator" or HPS) was designed and constructed. The HPS, the most advanced fracture simulator available to industry, is a vertical, variable-width, parallel plate flow apparatus capable of operating at high temperatures (up to 250 °F) and pressures (up to 1,200 psi). A state-of-the-art fiber optic based "vision system" was developed for the HPS to facilitate the visualization and accurate measurement of flow behavior of fracturing fluids with and without proppant. Some of the key experimental research areas include fracturing fluid characterization, wall slippage phenomena, dynamic fluid loss, perforation pressure loss, proppant convection and encapsulation, and proppant flowback. In order to duplicate actual field conditions, field methodologies and equipment for mixing, pumping, and fluid preconditioning were developed. A state-of-the-art laboratory for fracturing fluid characterization was also established at the same time. The HPS is now the anchor of the Well Construction Technology Center located at the University of Oklahoma. This multi-million dollar research facility offers industry a setting for testing hydraulic fracturing fluids has been in operation since 1993.

Detection and Prediction of Natural Fractures in Gas Reservoirs

Because tight gas reservoirs require a sufficient density of open, connected natural fractures to yield economical quantities of gas, new technologies for detecting and predicting the location of naturally fractured areas have consistently ranked among industry's highest priority R&D goals. To meet this need, the Department of Energy initiated its Detection and Prediction of Naturally Fractured Gas Reservoirs Project. This research program examined and tested a variety of techniques for natural fracture detection and prediction between 1992 and 1997, focusing on remote imagery for regional reconnaissance and advanced seismic and rock mechanics theory for local mapping and predicting of fracture zones and associated gas. A key criterion for all of these methods was cost effectiveness. Regional reconnaissance methods were tested to provide low-cost overviews that would guide later, more site specific, costly investigation. Advanced seismic methods and processing were found essential for

establishing the foundation for both fracture prediction and direct fracture detection. The six field R&D projects carried out under this program included:

- *Anadarko Basin, Conoco Borehole Project* – The objective of this project was to combine geology, geophysics and reservoir engineering to predict fluid migration in fractured rocks. The test facility was the Conoco Newkirk Borehole Test Facility in Oklahoma. A series of cross well seismic surveys were performed in the test wells at the research facility.
- *Powder River Basin, Fort Fetterman Rock Physics Project* – The objective of this project was to refine rock physics tools essential for linking seismic signatures to the characterization of fractured rock The Fort Fetterman project site is in a producing field in the southern Powder River Basin, Wyoming. Four nine-component 2-D survey lines (2D – 9C) were shot to define the dominant fracture trends at the site.
- *Uinta Basin, Bluebell-Altamont Field Multicomponent 2-D Seismic Project* – The objective of this project was to detect and characterize fractures using multicomponent seismic, VSP and other data. The Bluebell-Altamont field project is in a large producing field in the northern part of the Uinta Basin, Utah. Two orthogonal 2-D seismic lines and a vertical seismic profile (VSP) were acquired as part of the research project.
- *Piceance Basin, Rulison Field, Integrated Use of Imagery, 3-D Seismic and Geomechanics* – The objective of the project was to optimize and then demonstrate geophysical techniques for detecting naturally fractured areas in tight gas reservoirs. The project was located in the Rulison Field (Mesaverde tight, lenticular sands) in the south-centered Piceance Basin, Colorado, operated by Barrett Resources. The project used an integrated suite of Landsat–TM imagery, a high-resolution aeromagnetic survey, and 3-D, P-wave (multi-azimuth) seismic data. The initial data were incorporated into a geomechanical model to identify and predict areas underlain by intense, connected sets of natural fractures in two areas of the Rulison field.
- *Wind River Basin, Madden Field 3-D Seismic Anisotropy Project* – The objective of the project was to investigate cost-effective technologies for characterizing the spatial distribution of gas-producing natural fractures. The project site was in an established field in the Wind River Basin, targeting the Lower Fort Union Formation. A 3-D, P-wave survey was shot over a 37 square mile area on the western side of the field, followed by 2 square miles involving a 3-D, 3C seismic survey. The data were processed to establish natural fracture anisotropy and location from the larger P-wave and smaller (coterminous) S-wave survey.
- *Green River Basin, Table Rock Field 3-D Seismic and Geomechanics Project* – The objective of the project was to confirm the well site location (selected by the operator, Union Pacific Resources (UPR)) and help orient the direction of the horizontal well designed to intersect natural fractures. The project was located in the Table Rock Field (targeting the deep Upper Cretaceous Frontier Fm. at 15,000 feet) in the eastern

portion of the Greater Green River Basin. An existing 3-D, P-wave seismic survey was depth converted and processed to identify the major and minor fault systems in the area. The data were used as input into Advanced Resources International's (ARI) geomechanical model to predict the likely locations and boundaries of intense natural fracture clusters.

In addition to these projects, there have been more than a dozen DOE R&D projects carried out during the 1997-2006 time period that have focused on improving ways to locate natural fractured zones within tight gas reservoirs, improve fracture stimulation performance or otherwise enhance industry's ability to find and produce gas from tight sands. At least four ongoing projects are related to similar topics. All of these are highlighted on the NETL website.

Table 3.2.1: List of Major Research Reports for Western Gas Sands Program (1978-1992).

Report Number	Title	Authors	Organization	Date
DOE/BG/01569-14	Western Gas Sands Project: Northern Great Plains Province Review	Newman III, H.E.	Bartlesville Energy Technology Center	1979 Aug
DOE/BC/10003-13	Western Gas Sands Project: Stratigraphy of the Piceance Basin	Anderson, Stephen	Bartlesville Energy Technology Center	1980 Aug
DOE/NV/10249-5	Western Gas Sands Project: Completion and Production Summary Rulison Field, Piceance Basin, Colorado	Peterson, R.E.	Bartlesville Energy Technology Center	1982 Dec
DOE/BC/10003-16	Western Gas Sands Project: Production Histories of the Piceance and Uinta Basins of Colorado and Utah	Anderson, Stephen, Kohout, Julie	Bartlesville Energy Technology Center, Las Vegas Field Office	1980 Nov 20
DOE/BC/10003-23	Western Gas Sands Project: Interim Economic Analysis of Natural Gas Production from Tight Formations in Selected Western Basins	Bailey, William	Bartlesville Energy Technology Center, Las Vegas Field Office	1981 Jul
DOE/NV/10249-3	Western Gas Sands Project: An Approximation of Continuity of Lenticular Mesaverde Sandstone Lenses, Utilizing Close Well Correlations, Piceance Basin, Northwest Colorado		CER Corporation	1982 Nov
DOE/MC/24120-2769	Geologic and Production Characteristics of the Tight Mesaverde Group: Piceance Basin (Topical Report)	Myal, F.R., Price, E.H., Hill, R.E., Kukal, G.C., Abadie, P.A., Riecken, C.C.	CER Corp.	1989 Jul
DOE/MC/30070-94/C0289	Introduction to the GRI/DOE Field Fracturing Multi-Site Project	Peterson, R.E., Middlebrook, M.L., Warpinski, N.R., Cleary, M.P., Branagan, P.T.	CER Corp.	1993 Dec
	Development of Techniques for Optimizing Selection and Completion of Western Tight Gas Sands - Summary Report and Eight Phase Reports	Knutson, C.F., et al	CK GeoEnergy Corp.	1978-81
	Continuity and Permeability Development in the Tight Gas Sands of the Eastern Uinta Basin, Utah	Knutson, C. & C. Boardman	CK GeoEnergy Corp./Lawrence Livermore Laboratories	1978 May
	A Collection of Technical Data for Tight Gas Sands in Support of the Massive Hydraulic Fracturing System	Knutson, C.F. & C.R. Boardman	CK GeoEnergy Corp./Lawrence Livermore Laboratories	1978 Sep

Report Number	Title	Authors	Organization	Date
DOE/METC-85/2004	Status of models for analysis of Western Gas Sands	Horton, A.I. ; Layne, A.W.	DOE-METC	1985 Apr
DOE/METC-85/4052	Status of multiwell stimulation modeling analysis and western gas sands hydraulic fracture model development	Layne, A.	DOE-METC	1985 Aug
DOE/METC-85/4054	Hydraulic Fracture Model Analysis of the MWX Stimulation Treatments in the Paludal Interval Technical Note	Layne, A.W.	DOE-METC	1985 Aug
DOE/MC/24264-2654	Re-analysis of the MWX (Multi-Well Experiment) fracture stimulation data from the Paludal zone of the Mesaverde formation: Annual report, FY 1988	Smith, M.B. ; Miller, W.K. II	DOE-METC	1988 Nov
	U.S. Geological Survey Publications on Western Tight Gas Reservoirs, Topical Report	Krupa, M.P., Spencer, C.W.	DOE-METC	1989 Feb
	Analysis of Stratigraphic Barriers (Caprock) Between Sands in the Cretaceous Mesa Verde Formation, U.S. DOE Multiwell Experiment, Garfield County, CO	Soeder, D.J.	Institute of Gas Technology	1984 Jun
	Directional Core Analysis of the Mesa Verde Formation U.S. DOE Multiwell Experiment Garfield County, CO	Soeder, D.J.	Institute of Gas Technology	1984 Jun
	Effects of Water and Stress Upon Permeability to Gas of Paludal and Coastal Sands- U.S. DOE Multiwell Experiment Garfield County, CO	Randolph, P, J. Soeder, & P. Chowdish	Institute of Gas Technology	1985 Apr
UCID 52908	A Review of the Mechanics and Occurrence of Natural Fractures in Rock as Applied to the Development of the Tight Western Gas Sands	Towse, D.	Lawrence Livermore National Laboratory	1980 May 8
	In Situ Dynamic Elastic Moduli of Mesaverde Rocks and a Comparison With Static and Dynamic Laboratory Moduli	Lin, W. & F.E. Hueze	Lawrence Livermore National Laboratory	1986 Jan
	The LLNL Sonic Probe for In-situ Stress Measurements-Progress Report on Second Generation tool	Mao, Nai-hsien	Lawrence Livermore National Laboratory	1987 Sep
	Physical Models of Hydrofracturing Across Material Interfaces	Blair, S.C.,Thorpe, R.K., Heuze, H.K.	Lawrence Livermore National Laboratory	1988 Oct

Report Number	Title	Authors	Organization	Date
	Laboratory Observations of the Effect of Geological Discontinuities on Hydrofracture Propagation	Blair, S.C., et al.	Lawrence Livermore National Laboratory	1989 Jan
	Propagation of Fluid-Driven Fractures in Jointed Rock Part 1: Development and Validation of Methods of Analysis	Heuze, H.E., Shaffer, R.J., Ingraffea, A.R., Nilson, R.H.	Lawrence Livermore National Laboratory	1989 Sep
	Propagation of Fluid-Driven Fractures in Jointed Rock Part 2:Pysical Tests on Blocks with Interface or Lens	Heuze, H.E., Thorpe, H.K., Blair, S.C., Heuze, H.E.	Lawrence Livermore National Laboratory	1989 Sep
LA-1-374-PR	Western Gas Sands Project: Los Alamos NMR Well Logging Tool Development Final Report	Brown, Joseph A., Jackson, Jasper A., Koelle, Alfred R.	Los Alamos National Laboratory	1985 Mar
	Further Development of a Fracture Model for Lenticular Gas Sands	Palmer, I.D. & C.T. Luiskutty	Oral Roberts University	1985 Apr
SAND81-0938	The Formation Interface Fracturing Experiment: An In-situ Investigation of Hydraulic Fracture Behavior Near a Material Property Interface	Warpinski, N., Northrop, D., Schmidt, R., Vollendorf, W. and Finley, S.	Sandia National Laboratories	1981 Jun
SAND-83-1827C;CONF-8310162-5	Mineback Stimulation Research Program	Warpinski, N.R.	Sandia National Laboratories	1983 Jan
SAND-83-2100C;CONF-8310162-1	MWX stimulation experiments	Northrop, D.A.	Sandia National Laboratories	1983 Jan
SAND-83-2102C;CONF-8310162-3	Summary of tight-gas-sands sedimentology at the MWX site	Lorenz, J.C.	Sandia National Laboratories	1983 Jan
SAND-83-2135C;CONF-8310162-7	Seismic investigation of the Multi-Well Experiment site	Searls, C.A.	Sandia National Laboratories	1983 Jan
SAND-83-2140C;CONF-8310162-4	Multi-Well Experiment core program	Sattler, A.R.	Sandia National Laboratories	1983 Jan
SAND88-1008	Multiwell Experiment Final Report II. The Paludal Interval of the Mesaverde Formation		Sandia National Laboratories	1988 May

Report Number	Title	Authors	Organization	Date
	EGR Stimulation Research Project- Direct Observation of Hydraulic and Dynamic Fracturing	Northrop, D.A., N.R. Warpinski, & R.A. Schmidt	Sandia National Laboratories	
SAND-82-0604	Sedimentology of the Mesaverde Formation at Rifle Gap, Colorado and implications for gas-bearing intervals in the subsurface	Lorenz, J.C.	Sandia National Laboratories	1982 Mar
	Multi-Well Experiment MWX-3 As Built Report	CER Corporation	Sandia National Laboratories	1984 Feb
	The Multiwell Experiment Geophysics Program Final Report	Searls, Craig A.	Sandia National Laboratories	1985 Sep
SAND87-0327	Multiwell Experiment Final Report I. The Marine Interval of the Mesaverde Formation	Multiwell Experiment Project Group,CER Corporation	Sandia National Laboratories	1987 Apr
	Reservoir Sedimentology in the Mesaverde Rocks at the Multi-Well Experiment Site and East Central Site	Lorenz, John C.	Sandia National Laboratories	1987 Jun
	Passive Seismic Monitoring of Hydraulic Fracture Experiments at the Multiwell Experiment Site	Thorne, B.J., Morris, H.E.,	Sandia National Laboratories	1988 Aug
	Significance of Drilling-and Coring-Induced Fractures in Mesaverde Core, Northwestern Colorado	Lorenz, John C., Finley, S.J.	Sandia National Laboratories	1988 Jun
	Characterization of Natural Fractures in Mesaverde Core from the Multiwell Experiment	Finley & Lorenz	Sandia National Laboratories	1988 Sep
	Multiwell Experiment Final Report III. The Coastal Interval of the Mesaverde Formation	Multiwell Experiment Project Group,CER Corporation	Sandia National Laboratories	1989Jan
	Multiwell Experiment Final Report IV. The Fluvial Interval of the Mesaverde Formation	Multiwell Experiment Project Group,CER Corporation	Sandia National Laboratories	1990 Jan
SAND-91-0281C	Meas. And Analysis of Fractures in Vertical, Slant and Horizontal Core (Mesaverde examples)	Lorenz, J.C., Hill, R.E.	Sandia National Labs	1991

Report Number	Title	Authors	Organization	Date
DOE/MC/28130-3534	Reserves in Western Basins; Part I: Greater Green River	The Scotia Group	The Scotia Group	1993 Oct
DOE/MC/21119-2548-Vol.1	Stimulation model for lenticular sands: Volume 1: Final report	Rybicki, E.F.; Luiskutty, C.T.; Sutrick, J.S.; et al.	US Department of Energy	1987 Jul
	A Slant Hole Drilling Test at the DOE Multiwell Experiment Site in Colorado's Piceance Basin- Well Program	Frohne, K.H.	US Department of Energy	1987
	Geologic Studies in Support of the U.S. Department of Energy Multiwell Experiment, Garfield County, CO	Spencer C.W. & C.W. Keighin	US Geological Survey	1984
	U.S. Geological Survey Publications on Western Tight Gas Reservoirs	Spencer, Charles W., Krupa, M. Patricia	US Geological Survey	1985
	Geologic History and Hydrocarbon Potential of Late Cretaceous Age, Low Permeability Reservoirs, Piceance Basin, Western CO	Johnson, R.C.	US Geological Survey	1987 Mar
	Estimates of Gas Resources in Overpressured Low Permeability Cretaceous and Tertiary Sandstone Reservoirs, Greater Green River Basin	Law, B.E. et al.	US Geological Survey	

3.3. Methane Recovery from Coalbeds Program (1978-1982)

During the natural process of coal formation, methane is generated and trapped in the coal seam as well as the adjacent rock strata. All coal deposits contain methane, although the concentrations vary from seam to seam and within the seam. Estimates of the total magnitude of the U.S. coal-associated methane resource have ranged from less than 100 trillion cubic feet (Tcf) to more than 800 Tcf. Of the 400 Tcf figure cited by most sources, perhaps 100-150 Tcf may be technically recoverable. The USGS completed assessments in six key Rocky Mountain basins as part of the 1995 National Oil and Gas Assessment and determined that a mean of 44.6 Tcf is technically recoverable from those major sources of what is now commonly called "coalbed methane (CBM)." In 2005, coalbed methane production totaled 1.732 Tcf, or about 10 percent of unassociated gas production in the U.S.

However, before the Methane Recovery from Coalbeds Program (MRCP) was begun in 1978, this resource was either unrecognized or ignored by industry. The shortage of natural gas during the 1970s focused attention on methane from coal seams as one of the potentially significant sources of gas (along with gas from tight sands and Devonian shales) that might be developed to meet growing demand. Safety considerations in active coal mines had previously led the U.S. Bureau of Mines to begin the development of techniques for methane removal, and with the techniques in practice at the time an estimated 250 MMcfd of methane was being emitted to the atmosphere. The capture of this valuable resource, as well as production of the methane available from "unminable" coalbeds (too deep or too thin), was the ultimate goal of the Methane Recovery from Coalbeds Program (MRCP).

The Natural Gas Policy Act of 1978 provided some economic incentives for commercial exploitation of CBM. There were, however, still many barriers to its extensive recovery and utilization on a commercial basis. The technical, operational, and economic viability of production methods had not yet been sufficiently demonstrated to attract private investment. The quality of coal-associated gas varied from essentially pure methane for predrained gas, to variable combinations of methane and air for gob gas (gas emitted from the rubblized "gob" created during longwall mining), to extremely diluted methane-air mixtures in ventilation air. The resource was generally located remotely with respect to demand and individual wells had relatively low production rates. As well, coal operators had a legal right to release methane in the course of mining, and were wary of the legal implications of gas recovery since, generally, natural gas rights are held by others. Because the market value of a ton of coal was on the order of 100 times the value of the methane contained therein, coal mining companies had scant interest in gas-derived revenues relative to their primary objective of coal production.

Early work on CBM carried out by the U.S. Bureau of Mines had focused on pre-draining and capturing methane from the active, gassy mines of the Appalachian and Warrior basins. The Bureau of Mines program was assumed by DOE in 1978 and funded for five years. Subsequent R&D related to CBM was conducted chiefly by the Gas Research Institute (GRI) and industry.

The MRCP was aimed mostly at defining the size and recoverability of the resource base and the use of natural gas recovered during active coal mine operations. Several pilot field projects were conducted, including testing the use of vertical wells in deep, unminable coalbeds; testing the use of vertical wells in multiple coalbeds; and combining in-mine, multiple horizontal boreholes and CBM-fueled gas turbines for on-site power generation. Experiments in hydraulic fracture stimulation, conducted by the Bureau of Mines and later by DOE, demonstrated the utility of this technology in CBM recovery. In addition to DOE's Fossil Energy program, the DOE Small Business Innovative Research program funded several projects involving strategies for wellsite selection, drilling practices, and well-completion techniques for coal-bed methane production.

MRCP funding from 1978 to 1982 totaled about $30 million, nearly all of which was expended during the three-year period of 1979-1981. Significant cost sharing was obtained from industry for the vertical well pilot project and the hydraulic fracture mine-back efforts on the Warrior Basin.

A significant part of the responsibility for the ultimate development of the CBM resource can be attributed to the R&D efforts of GRI (which made CBM research a high priority) and to the industry activity that followed the provision of tax credits as incentives for development of the resource. The tax credits, together with basic and applied research, were instrumental in establishing an industry that now thrives (without incentives) and that has remained competitive through a period of relatively low natural gas prices (1988-89 and 1991-92). Nonetheless, DOE played a critical role in recognizing the commercial potential of CBM, in initially assessing the magnitude of the resource, and in carrying out early pilot field tests.

3.3.1. Key Questions Related to Coal Seam Methane

In the late 1970s, very little quantitative information was available related to the gas content of the Nation's coal seams, beyond those being actively mined. The information that was available was not public or easily accessed. Because coal seams had not been seen as a natural gas reservoir, no data were available on how coal seam wells should be drilled and completed, how the reservoir should be stimulated, or how coal seams could be economically produced. Key questions concerning the potential of coal seam gas as a source of domestic supply were:

- What is the distribution of coal seam methane?
- How does the quality and producibility of coal seam methane vary with location?
- What are cost effective ways of recovering this methane resource?
- What are cost effective ways of utilizing this methane given its quality and location relative to markets?
- How can methane that is being drained from coal seams prior to mining be captured and conserved?
- How can methane recovery from coal seams be modeled to obtain predictions of well productivity and resource recovery?
- How will systems for systems and techniques for producing methane from coal seams work under actual field conditions?
- What are the legal and institutional constraints on development of coal seam gas in the US?

The ranges of coal seam gas content, gas quality, and geographic location of coalbed methane sources made it apparent that no single solution would be appropriate for all cases. Earlier Bureau of Mines work had indicated that economic gas recovery/utilization might be possible via direct pipeline injection, conversion to LNG, use for on-site power generation, or petrochemical production. In some cases, it was felt that off-the-shelf technology could be modified for these applications (i.e., gas turbines, LNG production units, and ammonia production units).

3.3.2. MRCP Program Design and Overview

The MRCP, as it was initially envisioned, was designed around four primary activities:

- *Evaluation* – To reduce uncertainty regarding the potential of the coalbed methane resource and direct project priorities toward realizing that potential.
- *Resource and Site Characterization* – To acquire sufficiently accurate geologic understanding of reservoir areas and specific local sites to guide the design of effective recovery technologies.
- *Research, Instrumentation, and Modeling* – To develop the tools, procedures, measurements, concepts, and models required to produce methane from coalbeds
- *Production Technology Development* – To design, develop, and field test cost effective equipment and methods to produce gas from coalbeds.

The objectives of the *Evaluation* activity were to:

- Assess the results of the other activities,
- Continue the development of the coalbed methane data base begun pre-MRCP,

- Assess recent technological developments and related industry activities,
- Update estimates of the potential of the resource, and
- Develop and monitor project plans that reflected the integration of the technical, geologic, economic, and other types of data that resulted from the project.

Meeting these objectives was to be accomplished by:

- *Analysis and Assessment of the Resource* – Evaluating resource properties, developing exploration methods, selecting target areas and drilling sites, updating estimates of the resource/reserves, and providing characterization test planning and analysis.
- *Providing Project Information Management and Technology Transfer* – Providing for management of information resulting from the project and making pertinent portions of this information available to all potential users.
- *Providing Project Direction, Integration, and Support* – Identifying and initiating project support activities, identifying and analyzing constraints to exploitation of the resource, and determining the economics of methane extraction/preparation and upgrading systems.

The objectives of the *Resource and Site Characterization* activity were to:

- Characterize the methane content of the Nation's coalbeds, which up until then had been done on a very limited basis,
- Provide the knowledge needed to locate recovery and utilization projects in coalbeds with the greatest potential for methane production.

Meeting these objectives was to be accomplished by:

- *Acquisition and Analysis of Existing Resource Characterization Data*.
- *Identification of Potential Sites for Recovery Systems*.
- *Acquiring Reservoir Geologic Data* – For the target reservoir areas, obtaining the geologic data necessary to support evaluation and assessment of the coalbed methane resource.
- *Core, Log, and Test Wells of Opportunity* – Performing core tests, logging, sample analysis, and flow tests (where possible) to obtain and correlate coal and methane data.
- *Compilation of a Database*.

The objectives of the *Research, Instrumentation, and Model Development* activity were to:

- Improve or develop new diagnostic techniques,
- Improve or develop new stimulation approaches, and
- Improve the ability to accurately predict and measure reservoir response to stimulation techniques.

Fulfilling these objectives required basic and applied R&D in the laboratory and the field and the development of models. Models and instrumentation were to be evaluated and refined based upon the performance of tests conducted in the field. Specific tasks included:

- *Conducting Extraction Technology R&D* – This task was to continue throughout most of the life of the project.
- *Developing/Modifying Drilling Techniques and Equipment* – Drilling techniques included horizontal drilling and directional drilling, while equipment included downhole motors and waterjet drilling.
- *Performing Stimulation Experiments* – Performing multi-seam stimulations and completions from single vertical boreholes. Designing stimulations to maximize production but to minimize roof damage, especially in minable coal seams. Testing hydraulic, foam, gas, and dendritic stimulation designs.
- *Developing LNG Conversion Capacity* – Developing equipment sized for cost effective liquification near the recovery site of gas from coalbeds.
- *Developing Membrane Separation Capability* – Developing equipment and techniques to upgrade low-quality gas from coalbeds so that it would be suitable for pipeline injection.
- *Developing Mixed-Gas Upgrading Capability* – Developing equipment and techniques to remove contaminants from gas recovered from coalbeds to the extent that its use would be feasible and cost effective.

Finally, the objectives of the *Production Technology Development* activity were to:

- Design, operate, and field test coalbed methane integrated systems,
- Investigate and resolve variables that would be encountered under field (operational) conditions, and
- Evaluate the systems/subsystems and operating methods tested, for technical and economic feasibility and readiness for commercial ventures.

Meeting these objectives was to be accomplished through tasks under two major categories:

- *Technology Test Projects Associated with Active Mine Coalbeds* – Conducting a series of individual field test projects; each usually involving an integrated system.
    - Multiple Well Projects – New and improved methods would be investigated for draining methane in advance of mining operations.
    - Horizontal Borehole Drainage Projects – New and improved equipment and methods will be investigated for horizontal borehole drainage prior to or during mining operations.
    - Advanced Systems Test Projects, (Minable Coalbeds) – New equipment and methods would be field tested.

- *Technology Test Projects Associated with Presently Unmined Coalbeds* – Conducting a series of individual field test projects; each usually involving an integrated system.
    - Deep Coalbed Drainage Projects – Methane would be extracted from deep coal horizons, many of which would not be mined in the future.
    - Drainage Projects in Coalbeds Under Developed Areas – Methane would be extracted from coal seams that could not be mined because of their location under developed areas such as an urban community having multiple improvements on the surface.
    - Directional Drilling Coalbed Drainage Projects – Methane drainage would be accomplished using directional drilling techniques.
    - Advanced Systems Test Projects (Unmined Coalbeds) – New equipment and methods would be field tested.

The comprehensive R&D plan set forward at the start of the MRCP in 1978 was terminated in 1982, well before its scheduled completion, with further technology development to be the responsibility of the private sector.

DOE/Resource Applications (later part of DOE-Fossil Energy) funded 29 small-scale coalbed methane projects to evaluate the unminable coalbed resource as a commercial source of methane for local use. Twenty-one of these projects were designated as supplemental gas projects to political subdivisions (schools, towns, etc.) and the others were located on Indian reservations in the western U.S. These projects funded the drilling of wells and the gathering of coal desorption data.

3.3.3. Key Methane Recovery from Coalbeds Projects

Listed below are the key MRCP projects undertaken during the 1978-1982 time frame. The primary Technical Project Manager for the Methane Recovery from Coalbeds program during this time period was Charles W. Byrer. Other key technical project officers included: H.D. Shoemaker, John Duda, A.E. Hunt and Rodney Malone.

Technical and Commercial Feasibility of Utilizing Gas from Coalbeds and Devonian Shale for the Purposes of Community and Rural Development
Contracts: DC-FG01-79RA-33101
Performer: American Public Gas Association (APGA) and Gustavson Associates
Key Investigators: Arie Verrips, John Gustavson
Time Period: 1979+
Objectives: The objective was to drill coal and shale wells in a variety of states to demonstrate the economic feasibility of producing gas from such formations for rural utilities.

An Evaluation of the Effect of Methane Adsorption/Desorption in Well Tests on Coal Beds
Contracts: DE-AH21-85MC03193
Performer: University of Pittsburgh
Key Investigators: Alan A. Reznik, Gary A. Bayles
Time Period: 1985
Objectives: To evaluate the effect of methane desorption or adsorption on the analysis of pressure drawdown and build up data, respectively, during well testing on coal beds. The overall objective was to provide an analytical or semi-analytical method for determining the net permeability, area of drainage, reservoir shape, and deliverability of coalbed methane reservoirs, in order to provide a rapid method of assessment of coalbed methane as a potential energy source.

Carbon Dioxide for Methane Production Enhancement
Contracts: DE-FG21-80MC14262
Performer: University of Pittsburgh
Key Investigators: Alan A. Reznik
Time Period: 1980-1982
Objectives: To determine the feasibility of using carbon dioxide to optimize *in situ* production of methane from coal.

Measurement of Dynamic Reservoir Conditions
Contracts: DE-AC21-82MC-19404
Performer: U.S. Steel Corp. (Monroeville, PA)
Key Investigators: Charles M. Boyer II
Time Period: 1982 – 1985
Objectives: To evaluate the effectiveness of hydraulic fracture stimulations of coal seams by:

- Drilling a single-zone coalbed methane well in the Warrior Coal Basin (Blue Creek Coal) of Alabama,
- Performing static and dynamic reservoir tests to determine the reservoir properties of the target coal seam and the surrounding formations,
- Performing additional dynamic reservoir tests following stimulation to determine the effectiveness of treatment, and
- Mining out the coal seam in the wellbore area to directly observe and evaluate the induced fracture geometry.

Coalbed Methane Stimulation Analysis
Contracts: NA
Performer: METC In-house researchers
Key Investigators: G. Covatch, A. W. Layne
Time Period: 1979+
Objectives: The objective was to improve coal seam hydraulic fracturing techniques by improving the understanding of stimulation treatments. This was to be accomplished through examination of data from mine excavations, performing Nolte Analyses, and employing METC stimulation modeling codes.

Coalbed Methane Geostatistical Analysis Project
Contracts: NA
Performer: METC In-house researchers
Key Investigators: James C. Mercer
Time Period: 1979+
Objectives: The objective was to identify correlations between geologic parameters and gas production for wells completed in the Oak Grove (U.S. Steel) field in Alabama, by categorizing the wells based on production data and then constructing a set of classification criteria for predicting performance.

Evaluation of Data from Unmined Coal Seams
Contracts: DE-AC21-79MC10641, DE-AC21-80MC14255
Performer: Intercomp, Inc.
Key Investigators: H.S. Price
Time Period: 1979 – 1982
Objectives: To reduce the uncertainties in the critical parameters related to methane recovery from unmined U.S. coalbeds: thickness, permeability, pressure, gas content, relative permeability, hydraulic fracture length and hydraulic fracture conductivity.

Evaluation of Colorado Coal Bed Methane Potential
Contracts: DE-FG21-80MC14256
Performer: Colorado Geological Survey
Key Investigators: L.R. Ladwig
Time Period: 1978 – 1981+
Objectives: To provide technical assistance and support for resource delineation activities in Colorado and the Rocky Mountain area, including: selecting, evaluating and recommending drill test sites; synthesizing and summarizing pertinent geological information; monitoring industry activity and determining potential for cooperative agreements for testing, performing well-site geology supervision, and performing methane desorption of samples.

Evaluation of Utah Coalbed Methane Potential
Contracts: DE-FG-21-79MC11729
Performer: Utah Geological and Mineral Survey
Key Investigators: A.D. Smith
Time Period: 1979 – 1981+
Objectives: To provide technical assistance and support for resource delineation activities in the state of Utah, including the collection of available coal core samples for desorption of methane, preparation of a new Utah coal map based on the collection of data on coal depth, formation, interval, zone/bed, location and coal description.

Evaluation of Southern Coalfields
Contracts: DE-AC21-78MC08089
Performer: Virginia Polytechnical Institute and State University
Key Investigators: C.T. Rightmire (TRW)
Time Period: 1979 – 1980
Objectives: To determine methane production potential of Southern coalfields, with an emphasis on coal seams that are currently unmined, unlikely to be mined in the near future or unminable.

Resource and Site Characterization
Contracts: DE-AC21-78MC08089 (Task 2)
Performer: TRW Energy Systems Planning Division
Key Investigators: various
Time Period: 1979 – 1983
Objectives: To develop technology for the extraction and utilization of methane from coalbeds

Reservoir Fracturing and Mining Through Fractured Areas
Contracts: DE-AC21-78MC08089
Performer: Pennsylvania State University
Key Investigators: C.T. Rightmire (TRW)
Time Period: 1979 – 1980
Objectives: To evaluate the recovery of methane from fractured coal deposits and the impact of fracture stimulation on the subsequent mining of coal.

Effect of Predrainage Stimulation Techniques on Coal Recovery
Contracts: DE-AC21-78MC08089
Performer: Colorado School of Mines
Key Investigators: C.T. Rightmire (TRW)
Time Period: 1979 – 1980
Objectives: To evaluate the effect of premining methane drainage stimulation techniques on later coal recovery operations.

Fracture Mechanics
Contracts: DE-AT21-79MC11284
Performer: West Virginia University
Key Investigators: W.R. Powell
Time Period: 1979 – 1983
Objectives: To acquire fundamental knowledge of the mechanisms controlling fracture initiation and growth in coal. Tasks included:

- Quantifying the fracture toughness of coal,
- Identifying directions of natural weakness,
- Experimentally measuring the interactions of stresses, directions of weakness and fracture orientation,
- Determining influence of liquid flow rates, viscosity and stimulated tectonic stresses on the propagation of induced fractures,
- Developing models for the mechanical behavior of coal,
- Experimentally examining fractures to propagate across joints and boundaries, and
- Comparing fracture properties of coal with those of well-studied formations.

Development and Evaluation of Near Mine Stimulation Techniques for Coalbed Degasification
Contracts: DE-AC01-80ET14205
Performer: Dames and Moore
Key Investigators: D.J. Steele
Time Period: 1980 – 1982
Objectives: To gather information pertaining to the hydraulic stimulation process and supply the mining industry with a sound basis for decisions. Specifically, perform underground measurements and inspection of areas affected by stimulation treatment, determination of changes in mine roof integrity, and refinement of stimulation treatment design.

Investigation of Pore Structure Effects in Methane Released from Coal
Contracts: DE-AC21-78MC08089
Performer: University of New Mexico
Key Investigators: C.T. Rightmire (TRW)
Time Period: 1980 – 1982
Objectives: Field and laboratory studies to determine the validity of the "chip desorption" technique and to investigate the effects of pore structure in methane release from coal. Investigators collected coal cuttings from rotary drill and core drill mud and measured gas desorption rate. Investigators also performed physical characterization of coal samples and chromatic determination of micropore and marcopore diffusion coefficients.

Long Horizontal Holes (Active Mine Test Project, Buchanan Co., Virginia)
Contracts: DE-AC21-78MC08089
Performer: Occidental Research Corp.
Key Investigators: N.F. McGinnis (TRW)
Time Period: 1979 – 1981
Objectives: To develop a technique for recovery of methane from long horizontal holes drilled from within a mine, and for practical use of recovered methane.

Multiple Vertical Borehole Degasification Test Project (Jefferson Co., Alabama)
Contracts: ET-75-C-01-9027
Performer: U.S. Steel Corporation
Key Investigators: J.S. Wallace
Time Period: 1975 – 1980+
Objectives: To develop the capability of removing coalbed gas using a pattern of vertical boreholes, and to demonstrate this method's compatibility with the process of mining coal.

Directional Drilling for Degasification of the Pittsburgh Coalbed (Greene Co., Pennsylvania)
Contracts: ET-77-C-01-8891
Performer: Harold F. Scott (Bridgeville, PA)
Key Investigators: H. F. Scott
Time Period: 1977 – 1983
Objectives: To demonstrate the capability of using directional drilling techniques to drill long, horizontal methane drainage holes in coalbeds from a surface location to reduce the explosion hazard of methane/air mixtures during mining.

Vertical Drilling to Degasify the Jawbone Coalbed (Dickenson Co., Virginia)
Contracts: ET-77-C-01-9151
Performer: Clinchfield Coal Company
Key Investigators: T. Wallace
Time Period: 1977 – 1982
Objectives: To determine the feasibility of using vertical boreholes to drain methane gas from the Jawbone coalbed and to evaluate the relationship of borehole spacing on gas drainage rates.

Multiple Completion Development Test Project (Greene Co., Pennsylvania)
Contracts: DE-AC21-78MC08089
Performer: Waynesburg College
Key Investigators: N. F. McGinnis (TRW)
Time Period: 1979 – 1980
Objectives: To develop and demonstrate a multiple completion technique system, with consideration for the variable need for dewatering of each distinct zone, and for the utilization of the recovered methane in a local distribution pipeline.

Book Cliffs Coalfield Production Test Project
Contracts: DE-AC21-78MC10734
Performer: Mountain Fuel Supply Company (Salt Lake City, UT)
Key Investigators: R. L. Coates
Time Period: 1979 – 1983
Objectives: To determine effective extraction techniques for recovery and utilization of coalbed methane from deep (umined) horizons in the Uinta Basin, Carbon Co., Utah. Tasks involved drilling a series of vertical wells, hydraulically fracturing the wells, monitoring reservoir performance, developing completion techniques, and perfecting predictive reservoir modeling of methane production.

Formation and Retention of Methane in Coal
Contracts: DE-FG22-88PC88939
Performer: University of Utah
Key Investigators: V.J. Huck and D. M. Bodily.
Time Period: 1992
Objectives: Study the formation and retention of methane in ten Utah coal samples, one Colorado coal sample and eight samples from the Argonne Premium Coal Sample Bank.

Commercialization of Waste Gob Gas and Methane Produced in Conjunction with Coal Mining Operations
Contracts: DE-FG21-92MC29254
Performer: Resource Enterprises, Inc.
Key Investigators: various
Time Period: 1993
Objectives: Evaluate various gas conversion and enrichment processes for using gas recovered from longwall mining activity.

Variation in Quantity of Methane Adsorbed by Selected Coals as Function of Coal Petrology and Chemistry
Contracts: DE-AC21-80MC14219
Performer: GeoChem Research Inc.
Key Investigators: R.R. Schwarzer
Time Period: 1982
Objectives: To evaluate the methane adsorption capacity of 100 coal samples in relation to their chemical and petrological parameters using a multivariate statistical strategy. This was to be done in an effort to better understand the methane adsorption/desorption process and determine methods for improving methane release from coal.

Methane Utilization from Coalbeds
Contracts: DE-AC21-77ET13133
Performer: Westinghouse Electric Corporation
Key Investigators: various
Time Period: 1979 – 1981
Objectives: To demonstrate the technical feasibility of using coalbed methane locally for power generation.

Selected key reports and publications related to the research carried out during these contracts are listed in Table 3.3.1 and scanned copies are included on the CD.

3.3.4. Highlights of Important Results

The DOE effort was aimed mostly at defining the size and recoverability of the resource base as well as the use of natural gas associated with active coalmine operations.

The DOE CBM resource assessments established that a large, 400-Tcf natural gas resource was contained in coal seams. Fifty-three field tests were conducted in 10 geologic areas. Efforts focused on successfully collecting and analyzing coal samples for determination of gas content and performing geophysical logging to determine coalbed depth and thickness. Drill stem tests were conducted at six test wells. Gas content analyses were obtained from more than 300 samples taken from more than 50 sites in 10 basins: Arkoma, Green River, Illinois, Northern Appalachian, Piceance, Powder River, San Juan, Warrior, Western Washington and Wind River. A similar report was prepared for the Richmond Basin of Virginia.

Basin reports were completed and published and estimated of gas-in-place determined for eleven basins: Arkoma, Greater Green River Region, Illinois, Piceance, Powder River, San Juan, Raton Mesa, Warrior, Western Washington, Uinta and Wind River. The total estimated CBM gas-in-place was determined to be between 45 and 259 Tcf.
A water jet directional drilling system designed to enhance production from vertical wells without the use of fracture treatments was built and field tested.

The feasibility of increasing the permeability of coal by igniting an explosive gas mixture within the natural fracture system of the coal seam was assessed and determined to be ineffective due to coal “fines” production.

Significant research was conducted to better understand the mechanisms controlling fracture initiation and propagation, leading to the confirmation that: in the absence of confining stresses, fractures will propagate along bedding planes, and that natural shale layers (stringers) within the coal have a definite influence on fracture toughness.

A drill cuttings desorption technique was tested to facilitate the determination of commercial quantities of methane during drilling without the need for coring procedures.

Production technology development efforts included the design, application and/or evaluation of 40 fracture treatments in six basins. These tests helped to demonstrate:

- Technical feasibility of completing a well in multiple coal seams from a single wellbore,
- Economic production could be achieved from a multiple completion in spite of low methane content of individual seams,

- Predrainage of methane by drilling long, horizontal holes from within a mine is compatible with longwall mining operations,
- Drilling of long, horizontal holes can be accomplished without a complicated guidance system if operators are trained to distinguish between the drill string's response to drilling coal versus roof or floor rock,
- Methane collection systems can be properly designed to safely collect gas from a number of boreholes and transport it to the surface using polyethylene pipe,
- Nitrogen-generated foam appears to be suitable for stimulating coalbeds, and
- Use of coalbed methane to provide fuel sources for onsite power generation, process heat and coal drying is technologically viable.

DOE's initial coal-bed methane R&D program provided a significant portion of the basic R&D that formed the scientific knowledge base for this gas resource, and established the essential coal-bed methane storage and flow mechanisms, including adsorption, desorption, diffusion, and fracture-dominated flow.

A major breakthrough occurred when DOE demonstrated that CBM could be efficiently produced using vertical wells, as opposed to only using in-mine horizontal boreholes. The program also supported field tests that demonstrated the mechanisms of methane storage and flow in a near-commercial setting (a closely spaced well pattern) and supported field tests of the performance and effectiveness of using hydraulic fracturing to stimulate gas flow from coal seams in a series of test wells followed by mine-back experiments. Conducted by the Bureau of Mines and later by DOE, these demonstrated the utility of this technology in coal-bed methane recovery and that coal seams could be efficiently and safely hydraulically fractured, thus accelerating the rates of gas flow in these low-permeability formations.

The National Research Council report titled *"Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000"* published in 2001, reports economic benefits from DOE CBM research of $499 million (1999 dollars) in increased revenues and cost savings to producers, primarily from the Warrior and San Juan basins. In addition, $91 million (1999 dollars) is credited from royalties on federal lands and from increased state severance taxes due to displacement of imports. If DOE were credited with one-third of the benefits, this would amount to about $200 million, compared to a total investment of about $30 million.

The DOE CBM program demonstrated that even with a modest amount of funding over a relatively short period, early involvement of public research can prove beneficial. The initial work by DOE led GRI to take up CBM R&D and make it a top priority, and it stimulated industry interest, which coupled with production incentives in the form of tax credits, created an entirely new supply of natural gas.

3.3.5. Subsequent Research Related to Methane Recovery from Coalbeds

With the winding down of DOE-funded CBM research, GRI's research program in coalbed methane grew dramatically. Some of GRI's early work continued work that had been initiated by DOE, using some of the same contractors and industry partners. GRI's efforts focused on:

- Technology Development (formation evaluation, fracturing effectiveness and reservoir modeling).
- Field Tests (deep coal fracturing tests and multizone production tests).
- Management (program evaluation and technology transfer to industry).

GRI began in 1981 with a modest CBM R&D effort in funding four projects: a drilling fluids study undertaken by the Institute of Gas Technology (IGT), a coalbed dewatering study by TRW, a reservoir modeling effort underway with U.S. Steel, and in-house fracture stimulation testing. In 1982, with the scale-back of the DOE program, GRI initiated seven additional major projects, including field tests with U.S. Steel (in Alabama's Warrior Basin) and Resource Enterprises (in the Southern Piceance Basin). GRI also began publishing a quarterly report on their R&D efforts and the growing amount of industry activity related to coalbed methane. GRI also helped to sponsor a regular symposium on the topic.

GRI CBM R&D continued during the shift from a resource-based program to a technology-based program in the mid-1990s. Significant new efforts related to CBM R&D ended in the late 1990s. A complete listing of GRI reports on CBM topics is provided within the spreadsheet bibliography accompanying this report.

By the end of the decade, CBM production was more than six times the volume produced in 1990, and industry was effectively utilizing much of the information and technology that had been initiated and developed by DOE and GRI.

Table 3.3.1: List of Major Research Reports for MRCP (1978-1982).

Report Number	Title	Authors	Organization	Date
DOE/MC/03193-2211	An Evaluation of the Effect of Methane Adsorption/Desorption in Well Tests on Coal Beds (Final Technical Report)	Bayles, G.A.; Reznik, A.A.	University of Pittsburgh	1986 Sep
DOE/MC/16015-1368-Vol.1	Chip desorption and pore-structure effects in methane release from coal. Final report (Vol. 1 of 2)	Williams, F.L.	University of New Mexico	1983 Jan
DOE/MC/16015-1368-Vol.2	Chip desorption and pore-structure effects in methane release from coal. Final report (Vol. 2 of 2)	Williams, F.L.	University of New Mexico	1983 Jan
	Coal Mine Natural Gas Power Generation (Phase II Final Report)	Soot, P.M.	Northwest Fuel Development	
DOE/METC/SP-208	Coalbed Methane (Topical Report)		METC	1984 Dec
DOE/MC/19395-1413	Coalbed Methane Desorption Data		Colorado Geological Survey	1983
	Coalbed Methane Geostistical Analysis Project (Final Report)	Caceres, F.; Pratt, S.; Robey, E.; Wojewodka, R.		1985 Jul
DOE/METC-86/4055	Coalbed methane modeling analysis (Technical Note)	Covatch, G.L. ; Layne, A.W. ; Salamy, S.P.	METC	1985 Dec
	Coalbed Methane Production Case Histories		TRW Energy Systems	1981 Feb
DOE/METC/SP-202	Coalbed methane recovery and utilization in the United States		METC	1983 Dec
DOE/METC-86/0233	Coalbed methane: Technology status report		METC	1986 Jan
DOE/METC-87/0251	Coalbed methane: Technology status report		METC	1987 Jan

Report Number	Title	Authors	Organization	Date
	Coalbed/Devonian Shale Degasification Project (Vol. 1: Exec. Summary)		Gustavson Associates	1986 Nov
	Coalbed/Devonian Shale Degasification Project (Vol. 2: Project Summary)		Gustavson Associates	1986 Nov
	Coalbed/Devonian Shale Degasification Project (Vol. 3: Application Guide for Small Utility)		Gustavson Associates	1986 Nov
	Coalbed/Devonian Shale Degasification Project (Vol. 4: How To Manual: Well Feasibility and Installation)		Gustavson Associates	1986 Nov
DOE/MC/10737-1436	Demonstration Project for Methane Recovery from Unmineable Coalbeds (Final Report)	Allred, L.D.	Mountain Fuel Supply Co.	1982 Aug
	Desorbed Gas Measurement System Design and Application		TRW Energy Systems	1981 Mar
DOE/MC/19334-1692	Development potential of coalbed methane in the Warrior Coal Basin of Alabama (Chapters 1, 2, and 3)		University of Alabama	1984 May
DOE/MC/19334-1693	Development potential of coalbed methane in the Warrior Coal Basin of Alabama (Chapters 4, 5, and 6)		University of Alabama	1984 May
	Economic Analysis of Vertical Wells for Coalbed Methane Recovery	Gillies, A.; Snygg, A.; Fox, W.	TRW Energy Systems	1981 Mar
	Evaluation of a Coalbed Degasification Production Test		Intercomp Resource Development and Engineering, Inc.	1979 Aug
	Evaluation of Data Gathered from Unminable Coal Seams		Intercomp Resource Development and Engineering, Inc.	1982 Jun
	Evaluation of gas bearing coal seams	Rieke, H.H. ; Rightmire, C.T.; Fertl, W.H.	TRW, Dresser Atlas	1979

Report Number	Title	Authors	Organization	Date
	Formation and Retention of Methane in Coal (Final Report)	Hucka, V.J.; Bodily, D.M.; Huang, H.	University of Utah	1992 May
	Geologic overview, coal and coalbed methane resources of Raton Mesa Region, CO and NM	Jurich, D.	TRW Energy Systems	
	Geologic overview, coal and coalbed methane resources of the Arkoma Basin, Arkansas and Oklahoma	Rieke, Herman H.	TRW Energy Systems	
	Geologic overview, coal and coalbed methane resources of the Warrior Basin, AL and MS	Hewitt, J.L.	TRW Energy Systems	
	Geologic overview, coal and coalbed methane resources of Wind River Basin	Rieke, Herman H.	TRW Energy Systems	1981 Mar
	Geologic overview, coal deposits, and potential for methane recovery from coalbeds, Piceance Basin, CO	Choate, Raoul; Jurich, David; Saulnier Jr., George J.	TRW Energy Systems	1981 Mar
	Geologic overview, coal deposits, and potential for methane recovery from coalbeds, Powder River Basin	Choate, Raoul; Johnson, Carol	TRW Energy Systems	
	Geologic overview, coal deposits, and potential for methane recovery from coalbeds, Uinta Basin, UT and CO	Adam, M. A., Kirr, J. N.	TRW Energy Systems	1980 Dec
	Geologic overview, coal resources, and potential methane recovery from coalbeds, Central Appalachian Basin, MD, WV, VA, KY, TN	Adams, M.A.	TRW Energy Systems	1982 Jun
	Geologic overview, coal resources, and potential methane recovery from coalbeds, Northern Appalachian Coal Basin, PA, OH, MD, WV, KY	Adams, M.A., Eddy, G.E., Hewitt, J.L., Kirr, J.N., Rightmire, C.T.	TRW Energy Systems	1982 Nov
	Measurement of Dynamic Coalbed Reservoir Conditions Required to Design Near-Mine Methane Control Activities in the Warrior Basin	Boyer, C.M.; Stubbs, P.B.	US Steel Corp.	1983 Feb
	Measurement of Dynamic Reservoir Conditions, Volume 1. Final Report	Boyer, C.M.; Briscoe, F.H.; Camp, B.S.; et al.	US Steel Corp.	1986 Dec

Report Number	Title	Authors	Organization	Date
	Methane Drainage Ahead of Mining Using Foam Stimulation, Mary Lee Coalbed, Alabama	Lambert, Stephen W.; Trevits, Michael A.	US DOE	1979
	Methane Drainage in Advance of Mining Through Horizontal Boreholes (Final Report for Apr 1979-Dec 1980)	Von Schonfeldt, H.	Occidental Research Corp. for TRW	1981 Mar
	Methane Drainage with Horizontal Boreholes in Advance of Longwall Mining (Tech and Economic Feasibility)- Final Report	Gabello, D.P.; Felts, L.L.; Hayoz, F.P.	TRW Energy Systems	1981 Mar
	Methane Drainage: Experience With Hydraulic Stimulation Through Slotted Casing	Lambert, Stephen W.; Trevits, Michael A.	DOI-USBM	1978
	Methane from Coalbeds Collection and Utilization Systems		TRW Energy Systems	1981 May
MERC/SP-78/1	Methane Gas from Coalbeds-Development, Production and Utilization		MERC	1978 Apr
	Methane Potential from Coal Seams in the Richmond Basin of Virginia		Virginia Polytechnical Institute and State University	1981 Mar
MERC/CR-77/4(Vol.1)	Methane Produced from Coalbeds (Systems Studies of Energy Conservation) Vol. 1 of 2		TRW Energy Systems	1977 Jan
MERC/CR-77/4(Vol.2)	Methane Produced from Coalbeds (Systems Studies of Energy Conservation) Vol. 2 of 2		TRW Energy Systems	1977 Jan
	Methane Recovery from Coalbeds Project plan document, FY 1980		METC	1979 Nov
	Methane Recovery from Coalbeds Project plan document, FY 1981		TRW Energy Systems	1980 Sep
	Methane Recovery from Coalbeds Project plan document, FY 1982		METC	1981 Nov

Report Number	Title	Authors	Organization	Date
DOE/METC-83-76	Methane Recovery from Coalbeds: A Potential Energy Source	Mroz, T.H. ; Ryan, J.G. ; Byrer, C.W.	METC	1983 Oct
DOE/MC/16373-56	Methane Recovery from Horizontal Holes in Advance of Mining	Pothini, B. Rao	Occidental Research Corp.	1982 Mar
	Methane Recovery from Multiple Coal Seams (Final Report)		Waynesburg College	1980 Dec
	Methane Utilization from Coalbeds for Power Generation (Final Report)		Westinghouse Corporation	1981 May
DOE/METC/SP-186	Preliminary resource assessment of coalbed methane in the United States		METC	1981 Apr
	San Juan Basin Report, a Study of Upper Cretaceous Geology, Coal and Coalbed Methane Resources of the San Juan Basin, in Colorado and New Mexico	Choate, Raoul; Lent, Judy A.; Rightmire, C.	TRW Energy Systems	1982 Jul
	Second Phase of a Coalbed Methane Extraction and Utilitization Program		Westinghouse Corporation	1980 Apr
	Studies of Fracture Mechanics of Coal (Final Report for Jun 1979-Nov 1980)	Powell, W.	West Virginia University	1980
	Test Program to Determine the Feasibility of Producing Methane from Unminable Coalbeds, Final Report		Intercomp Resource Development and Engineering, Inc.	1979 Apr
	The Feasibility of No-Proppant Stimulation to Enhance Removal of Methane from the Mary Lee Coalbed	Lambert, Stephen W.; Trevits, Michael A.	Carbondale Mining Technology Center DOE/CMTC/TR-80/1	1980 Apr
	The Geology of the Deep Coal in Iowa	Lemish, J.; Palmquist, R.C.	Iowa State University	1980 Nov
DOE/R4/10333-T3	US Department of Energy Region IV Unconventional Gas Program: summary and analysis	Telle, W.R. ; Thompson, D.A.	University of Alabama	1984 Dec

Report Number	Title	Authors	Organization	Date
	Utah Coal Core Methane Desorption Project (Final Report)	Smith, Archie D.	Utah Geological and Mineral Survey	1983
	Utilizing the Unconventional Gas Resources of the Pottsville Formation Coals in Tuscaloosa Co., AL		University of Alabama	1981 Nov
	Variation in the Quantity of Methane Adsorbed by Selected Coals as a Function of Coal Petrology and Coal Chemistry (Vol. 1 of 2)	Schwarzer, R. R.	GeoChem Research Inc.	1983 Jan
	Variation in the Quantity of Methane Adsorbed by Selected Coals as a Function of Coal Petrology and Coal Chemistry (Vol. 2 of 2)	Schwarzer, R. R.	GeoChem Research Inc.	1983 Jan
DOE/CMTC/TR-80/2	Vertical Borehole Design and Completion Practices to Remove Methane Gas From Mineable Coalbeds	Lambert, S.W., Trevits, M.A., Steidl, P.F.	Carbondale Mining Technology Center	1980 Aug
	Western Washington Coal Region Report, A Study of Early Tertiary Geology, Coal and Coalbed Methane Resource in Western Washington	Choate, Raoul; Johnson, Carol	TRW Energy Systems	

3.4. Deep Source Gas Project (1982-1992)

Deep source gas research was an outgrowth of DOE's Unconventional Gas Resource (UGR) program begun in 1976. The fundamental concept behind the research was that proving the existence of methane or methane-generating source rocks at great depths (>30,000 feet) could radically influence methods used to explore for new gas supplies.

The initial impetus came from a workshop held at METC in May 1982 to discuss the potential benefits of a research program that would investigate three possible types of deep source gas:

- *Abiogenic Gas* – derived from primordial, non-biologic origin hydrocarbons in the earth's mantle,
- *Subducted Organic Source Gas* – arising from plate tectonic emplacement at great depth of hydrocarbons from organically-derived (near surface) sources, and
- *Deep Sedimentary Basin Gas* – conventionally-sourced gas found in sedimentary rocks that have been tectonically downwarped to depths in excess of 30,000 feet.

The participants in this workshop (government, industry and academia) determined there was a need for conclusive data on the occurrence of methane from suspected deep sources and a DOE-led program to collect and analyze such data should be undertaken. Their recommendations included:

- Improving geophysical techniques,
- Coordinating geophysical and geochemical data to aid in evaluation of deep structural frameworks,
- Developing an improved scheme for the differentiation of gas origins,
- Implementing a cooperative effort in acquiring deep core samples from public and private sources,
- Expanding efforts to thermodynamically model rock gas systems, with comparisons to deep core sample phenomena as they become available (e.g., fluid inclusions), and
- Implementing field geologic studies on the western Cordilleran region of North America, with its relatively large unexplored area, abundant deep fault systems, allochthonous terranes, and adjacent convergent margin.

As a result of the workshop and other discussions, subsequent METC research became focused primarily on one of the deep source gas concepts: the subducted organic-origin concept. Central to this idea was the notion that natural gas could be generated in sediments carried to great depths by plate tectonic activity along convergent margins, and that this emplaced deep gas could also source shallower traps through deep fracture systems (see Figure 3.4.1).

The Cordilleran geologic province of North America was considered a prime candidate for study because it has both active and inactive subduction zones and contains thrust fault structures that enabled deep emplacement of hydrocarbon-generating sediments during the recent past (180 million years). The specific area of interest in this province encompassed about 1.5 million square miles of Western U.S., Alaska and Canada. Preliminary geochemical studies indicated that the deep-source-gas generating capacity of this region could be as much as 3000 Tcf.

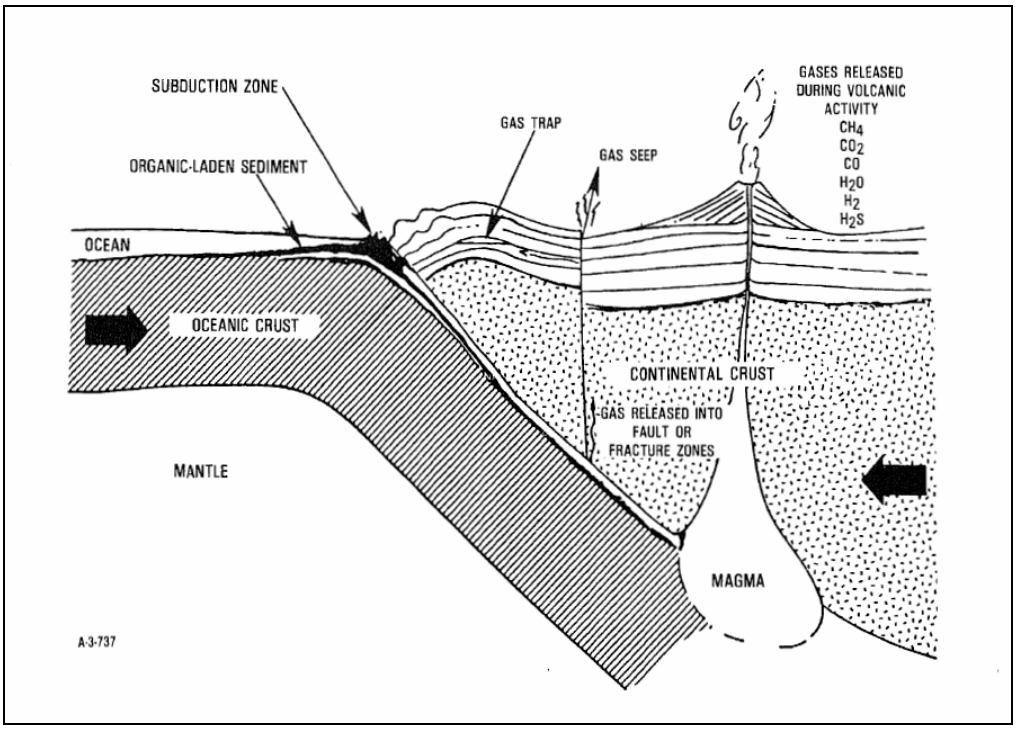

Figure 3.4.1: Schematic Illustrating the Concept of Deep Source Gas Associated with a Subduction Zone.

DOE funding was focused on establishing the existence of natural gas arising from these deep source zones, locating migratory paths, determining the existence of potential gas reservoirs, defining target areas and quantifying resources estimates. Geological characterization, consisting of geophysical and geochemical field studies of target areas in Northern California, Oregon and Washington, was initiated in FY 1984. This research was carried out through work conducted in-house as well as in cooperation with the U.S. Geological Survey. Additional work on theoretical studies of potential deep gas compositional variation and the development of gas detection/differentiation systems was also pursued.

The DOE project manager at METC primarily responsible for research efforts related to deep source gas was William Gwilliam. The most important products that resulted from the Deep Source Gas program were the result of the dozen or so key projects listed below. A number of these projects were carried out under a USGS/DOE Interagency Agreement.

3.4.1. Key Deep Source Gas Projects

Gas Generation from Subducted Sediment Along the Eastern Aleutian Trench
Contract: DE-AI21-83MC20422
Performer: USGS (Menlo Park, CA)
Key Investigators: Keith Kvenvolden, Roland von Huene
Time Period: 1983-1986+
Objectives: To evaluate the potential for occurrence of deeply generated gas resources along a modern convergent continental margin where subduction has been dominant by:

- Applying new processing sequences to two grids of data (20 lines, about 1,600 km) to allow development of a 3-D quantitative model and
- Using the 3-D structural model to explore potential migration paths and trapping structures in areas likely to be above the gas generation window.

Convergent Margin Geologic Characterization for Deep Source Hydrocarbon Potential
Contract: DE-AI21-83MC20422
Performer: USGS (Menlo Park, CA)
Key Investigators: David Howell, David Jones, Peter Coney
Time Period: 1983-1986+
Objectives: To evaluate the potential for occurrence of deeply buried hydrocarbons along a convergent continental margin by:

- Establishing the age, lithology and structural relations between and within thrust-bounded oceanic terranes that overlie continental platform assemblages in the central and eastern Brooks Range and Charlie River-Eagle areas,
- Establishing the thermal maturation and nature of constituents in possible source rocks in both continental and oceanic terranes,
- Identifying possible structural sites favorable for accumulation of deep gas resources, and
- Extending geologic data and geophysical data into Yukon Flats to evaluate the potential of the region.

Deep Investigative Geophysical Studies
Contract: DE-AI21-83MC20422
Performer: USGS (Denver, CO)
Key Investigators: William Stanley
Time Period: 1983-1986+
Objectives: To evaluate the potential for occurrence of deeply buried hydrocarbons along a convergent continental margin locating "suture" zones in the Mesozoic of the Cordillera where thick sedimentary sequences may have been thrust to large depths by accretion, through the use of electromagnetic sounding studies (magnetotellurics) integrated with gravity, magnetic, remote sensing and available seismic data.

Geologic Research of Conventional and Unconventional Hydrocarbon Resources, Task No. 2 Analysis of Deep Seismic Reflection and Other Data from the Southern Washington Cascades
Contract: DE-AT21-92MC29267
Performer: USGS (Denver, CO)
Key Investigators: William Stanley
Time Period: 1992
Objectives: Perform a synthesis of geological, geophysical, and geochemical data from a largely volcanic rock covered region in southwestern Washington that has been identified as being underlain by thick marine sedimentary rocks.

A Theoretical and Experimental Study of the Composition of Deep Source gas
Contract: DE-AC21-84MC-21229
Performer: University of Tulsa
Key Investigators: Colin Barker
Time Period: pre-1986
Objectives: Establish the composition of deep gas by thermodynamic calculation and by direct analysis of gases trapped in fluid inclusions.

Subduction Zone Tectonic Studies to Develop Concepts for the Occurrence of Sediment Subduction, Phase I
Contract: DE-MC-20213-1820
Performer: Texas A&M Research Foundation (College Station, TX)
Key Investigators: Thomas W.C. Hilde
Time Period: 1983-1985
Objectives: To define the tectonics of sediment subduction in deep ocean trenches. The project employed bathymetric data supported by marine seismic data to define the structures of trenches, sediment distribution and deformation through various stages of plate convergence, and the sediment subduction/accretion balance based on the factors controlling the fate of sediments at the trench.

Subduction Zone Tectonic Studies to Develop Concepts for the Occurrence of Sediment Subduction, Phase II
Contract: DE-AC21-83MC20213
Performer: Texas A&M Research Foundation (College Station, TX)
Key Investigators: Thomas W.C. Hilde
Time Period: 1983-1986
Objectives: To define the tectonics of sediment subduction in deep ocean trenches. The project employed bathymetric data supported by marine seismic data to define the structures of trenches, sediment distribution and deformation through various stages of plate convergence, and the sediment subduction/accretion balance based on the factors controlling the fate of sediments at the trench.

Hydrocarbon Generation at the Convergent Margin of Coastal Washington and Oregon
Contract: DE-AI21-83MC20422
Performer: USGS (Menlo Park, CA)
Key Investigators: Keith Kvenvolden, Parke D. Snavely
Time Period: 1984-1987
Objectives: To test a geologic model of the convergent margin of Washington and Oregon so that broad exploration targets and the petroleum potential of subducted Tertiary sedimentary rocks can be evaluated. About 160 samples, chiefly from biostratigraphically dated strata, were collected from widely spaced localities and analyzed for vitrinite reflectance and source rock characteristics. Gas and oil samples were collected from active seeps and two wells for geochemical and isotopic analysis. Comparisons were made between molecular markers in the oils and extracts from the rock samples.

Deep Gas in the Barbados Accretionary Prism
Contract: DE-RP21-84MC21132
Performer: Northwestern University
Key Investigators: R.C. Speed
Time Period: July 1985-July 1986
Objectives: To understand the processes and potential of gas generation in terrigenous-sediment rich forearcs at active convergent margins, and to provide an analog for the structural and hydrocarbon evolution of ancient accretionary complexes sutured against and above the edge of the North American continent. This study was particularly concerned with the relative thermal maturation rates in offscraped and under-riding sediment, thermal regimes at depth in the Barbados accretionary prism, tectonic activity at the inner side of accretionary prisms and the generation or regeneration of gas conduits

from depth, and tectonics or sedimentation that lead to gas reservoirs and seals in accretionary prisms.

Thermal History Modeling of Convergent Margins
Contract: DE-AC21-85MC22009
Performer: Columbia University Lamont-Doherty Geological Observatory
Key Investigators: Gerard Bond, Michelle Kominz
Time Period: Oct. 1985-Jan.1989
Objectives: To develop a generalized thermal model for forearc prisms and to apply the model specifically to the Oregon-Washington and southern Alaska margins. The predicted thermal history of the sediments was to be used to determine the likelihood of the production of significant accumulations of gas in these regions.

Detection/Differentiation System Development for Deep Source Gases
Contract: DE-AC21-84MC21131
Performer: Global Geochemistry Corp.
Key Investigators: W.A. Jeffery, Ian R. Kaplan, Harmon Craig
Time Period: October 1984 – December 1985
Objectives: To collect and analyze hydrocarbon gases from three major deep sources: sediments in deep subsiding basins, mantle release of abiogenic gas, and subducted sediments at convergent margins. The results of the analytical scheme were to be used to differentiate subduction zone gases from gases of deep sedimentary or mantle origins.

Methow Basin Paleomagnetic Analysis
Contract: DE-AP21-85MC03162
Performer: University of Pittsburgh
Key Investigators: V.A. Schmidt
Time Period: 1985
Objectives: To perform paleomagnetic measurements on 56 specimens from 31 cores taken from oriented rock samples collected from four separate formations from the Methow Basin of Northern Washington.

3.4.2. Highlights of Important Results

Perhaps one of the most important products of the Deep Source Gas program was a 140 mile (230 km) seismic reflection survey designed to describe the regional structural geology of the Washington-Oregon area and to determine the practicality of using reflection techniques in this region.

The boundaries of the study area (Figure 3.4.2) were based on a magnetotelluric survey conducted by the U.S. Geological Survey (USGS) as part of the Deep Source Gas

program. This survey delineated an anomalously conductive rock layer in an area roughly bounded by Mt. St. Helens, Mt. Adams, and Mt. Rainier. This feature, named the Southwestern Cascades Conductive Anomaly (SWCC), was interpreted to be caused by a sedimentary sequence underlying the surface volcanic layer.

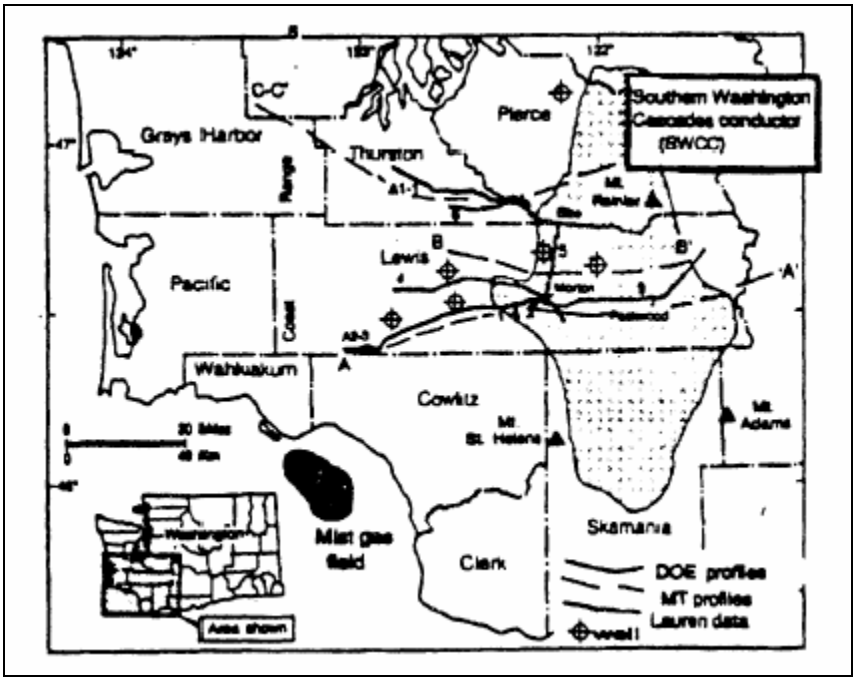

Figure 3.4.2: Index Map of SWCC Region with Location of DOE and Other Seismic Data and Magnetotelluric Profiles.

Previous exploration drilling had not tested these deep sediments, but other drilling in the Pacific Northwest had found shows of both oil and gas and had led to the discovery of the Mist gas field (42+ Bcf) of northern Oregon, the region's only commercial field. However, most exploration activity had been conducted before the development of modern plate tectonic theory.

Both the seismic reflection interpretation and associated maturity studies indicated that the study area contained sediments potentially favorable for hydrocarbon accumulations. The geologic model suggested by the study also indicated an extremely dynamic system that had evolved significantly over time, with complex interactions between structural formation and deposition.

In an epilogue to this study, in late 1997 Hunt Oil Company drilled a rank wildcat in Lewis County, Washington (HOC State No. 36-1). The well encountered hole problems

resulting from the stress conditions existing within the subsurface, and was abandoned at a depth of 10,342 feet, prior to reaching its target depth of 15,000 ft. While some shows were reported in the well, it did not reach the depth necessary to test the potential for deeper sediments suggested by the model.

Table 3.4.1: List of Major Research Reports for Deep Source Gas Program (1984-1992).

Report Number	Title	Authors	Organization	Date
USGS OFR 94-159	Analysis of Deep Seismic Reflection and Other Data from the Southern Washington Cascades (Task 2 Final Report)	Stanley, W.D.; Nuccio, J.	USGS	undated
DOE/MC/24155-3488	Deep Seismic Survey Extending from Western Washington to Mist Gas Field, Oregon - Final Report	Hollis, D.O.	Geophysical Systems Corp.	1992 Oct
DOE/METC/SP-215	Deep Source Gas - Topical Report	DOE-METC	DOE-METC	1985 Feb
DOE/METC-86/0234	Deep Source Gas. Technology status report	DOE-METC	DOE-METC	1986 Jan
DOE/METC-87/0250	Deep Source Gas: Technology status report	DOE-METC	DOE-METC	1987 Jan
DOE/METC-82-50	Deep Source Gas Workshop Technical Proceedings (May 3-4, 1982)	Gwilliam, W.J.; editor	DOE-METC	1982 Sep
DOE/MC/21131-2350	Detection/differentiation system development for deep source gases: Final report for Phase 1, October 1984-December 1985	Jeffrey, A.W.A.	Global Geochemistry Corp.	1987 Feb
	Hydrocarbon Production Gases from Subduction Zones - Topical Report		Global Geochemistry Corp.	1986 Jan
	Megascopic Descriptions of Rock Samples from the Methow Valley of Western Washington State - Technical Memorandum	Moore, R.A.	EG&G	1985 May
	Methow Basin Paleomagnetic Analysis	Schmidt, Victor A.	University of Pittsburgh	1985 Aug
93JJ-91-001	Overview of hydrocarbon exploration in Cenozoic tectonic basins of the Pacific NW, USA	Boswell, Ray	EG&G	1991 May
	Petrographic Analysis of Rock Thin-Sections from the Methow Valley, Western Washington State	Meyer, Theodore J.	EG&G	1985 Sep

Report Number	Title	Authors	Organization	Date
USGS OFR 84-404	Potential for Generation of Natural Gas in Sediments of the Convergent Margin of the Aleutian Trench Area	Kvenvolden, Keith A.; von Huene, Roland	USGS	1984
DOE/METC-86/6037	Proceedings of the Gas Hydrates, Arctic/Offshore Research, and Deep Source Gas Contractors Review Meeting	Komar, C.A.; editor	DOE-METC	1986 Jul
LBL-31982	Seismic Imaging of the SWCC	Daley, T.M.; Majer, E.L.	Lawrence Berkeley National Laboratory	1992 Jan
DOE/ER/13417-T1	Stability of natural gas in the deep subsurface. Final report	Barker, C.	University of Tulsa	1996 Jul
	Statistical Analysis of Geochemical Data for Methrow Valley Samples - Technical Memorandum	Moore, R.A. and Robey, E.H.	EG&G	1985 Sep
DOE-MC-20213-1820	Subduction Zone Tectonic Studies to Develop Concepts for the Occurrence of Sediment Subduction (Phase 1) - Final Report	Hilde, Thomas W.C.	Texas A&M	1984 Aug
DOE-MC-20213-2816 Vol. 1	Subduction Zone Tectonic Studies to Develop Concepts for the Occurrence of Sediment Subduction (Phase 2) - Final Report Vol. 1 of 3	Payne, Bandy, et al.	Texas A&M	1989 Feb
DOE-MC-20213-2816 Vol. 2	Subduction Zone Tectonic Studies to Develop Concepts for the Occurrence of Sediment Subduction (Phase 2) - Final Report Vol. 2 of 3	Payne, Bandy, et al.	Texas A&M	1989 Feb
DOE-MC-20213-2816 Vol. 3	Subduction Zone Tectonic Studies to Develop Concepts for the Occurrence of Sediment Subduction (Phase 2) - Final Report Vol. 3 of 3	Payne, Bandy, et al.	Texas A&M	1989 Feb
DOE/MC/21229-2065	Theoretical and experimental study of the composition of deep source gas. Final report	Barker, C.	University of Tulsa	1985 Jul
DOE-MC-22009-2785	Thermal Modeling of Forearc Regions - Final report	Kominz, M. A.; Bond, G. C.	Columbia University	1989 Aug

Report Number	Title	Authors	Organization	Date
DOE/METC-90-0271	Deep Gas	Gwilliam, W.J.	DOE-METC	1990 Jun
DOE/MC/21132-2560	Deep gas in the Barbados accretionary prism: Sources, migration, detection: Final report	Speed, R.C.		1987 Jun
SAND-82-2243C	Determination of in-situ stress from anelastic strain-recovery measurements of oriented core: applications to hydraulic-fracture-treatment design	Teufel, L.W.		1983 Jan
DOE/NBM-92001276	Generation of deep gas in sedimentary basins	Sweeney, J.J.; Lewis, A.E.; Burnham, A.K.; et al.		1992 Jan
	Geologic Mapping of the Morton Anticline - Lewis Co., Washington	Pappajohn, Steve	GeoTrends, Inc	1990 Nov
published paper	Natural Gas Generation in Sediments of the Convergent Margin of the Eastern Aleutian Trench Area	Kvenvolden, K.A., and R. von Huene	Tectonostratigraphic terranes of the Circum-Pacific Region: Earht Sciences Series, No.1, p. 31-49.	1985
DOE/MC/20422-92/C0026	Potential for deep natural gas resources in eastern Gulf of Mexico	Rice, D.D.; Schenk, C.J.; Schmoker, J.W.; et al.		1992 Jan

3.5. Methane Hydrates Program (1982-1992)

As a result of a growing body of evidence for the prevalence of methane hydrate in natural settings (e.g., reports of hydrate sourcing of the Messoyakha gas field in the northern part of Western Siberia in 1972 and the recovery of gas hydrate in a core of seafloor sediment during Leg 84 of the Deep Sea Drilling Program in 1982), the U.S. Department of Energy (DOE) became interested in the question: *What is the potential of methane from gas hydrates and what role should the U.S. Department of Energy play in pursuit of this resource?* Accordingly, in March 1982 a workshop was held at the Morgantown Energy Technology Center (METC) with three goals: to prioritize the critical R&D needs, to develop a meaningful R&D program consistent with the Government role, and to guide the very limited DOE R&D funds available in FY 1983 and beyond.

3.5.1. Methane Hydrates Workshop (March 1982)

The Workshop, attended by more than 60 individuals, aided in the identification of the correct community for sharing ideas and data, and laid the conceptual foundation for an R&D program which continued from 1982 through 1992.

The Workshop attendees came to the conclusion that there was a need for:

- The Federal Government to provide coordination, integration and synthesis of R&D program elements with the goal of ultimately establishing an estimate of future gas reserves from methane hydrates,
- The establishment of Government/industry cooperation in R&D,
- The development of techniques and procedures for the creation of synthetic hydrate cores for laboratory research,
- The acquisition of natural hydrate cores for the characterization of hydrates *in situ*,
- The development of agreements for information exchange with other countries,
- The establishment of both laboratory and field research programs, and
- The creation and maintenance of an in-depth knowledge base for future hydrate research.

In addition, workshop participants recommended that the Federal Government:

- Provide the coordination and integration and act as a focal point for future research related to gas hydrates,
- Prepare a plan that would lead to estimates of resource potential and economically recoverable reserves based on production technologies yet-to-be-designed,

- Develop agreements for cooperative research and work with oil and gas companies to establish agreements for wells-of-opportunity in the Kuparuk Field, Alaska, and to
- Develop plans for the collection of cores and logging information in the Arctic region and from wells-of-opportunity at marine locations.

3.5.2. Key Questions and Related R&D Goals

The 1982 Methane Hydrates Workshop participants outlined specific questions that needed answers, suggested goals for an R&D program, and outlined the status of existing hydrate R&D activity. The key questions were determined to be:

1. How does one detect naturally occurring hydrates?
2. What is the *in situ* concentration?
3. What is the overall quantity of the resource?
4. What will happen when attempts are made to produce gas from hydrates?
5. What techniques can be used to produce gas from hydrates?

The first steps in answering these basic questions were seen to be the characterization of hydrates in nature and the determination of how they dissociate within sediments. The first recommendation was that laboratory research focus on measuring properties of hydrates that would lead to a better understanding of the properties of naturally occurring hydrate zones within the earth, leading to the development of specialized detection techniques (well logging, seismic interpretation). The key properties requiring characterization were: density, thermal conductivity, compressibility, sound velocity, elastic wave velocity, and porosity.

Another recommendation was that laboratory research be undertaken to simulate the *in situ* conditions of hydrate-bearing sediments and also the behavior of the hydrates when pressure is reduced or thermal fluids are injected. Specifically, the goals were to:

- Determine the effects on decomposition of altering system heat capacity, thermal conductivity and interfacial phenomena such as heat transfer and mass transfer,
- Determine the effects of the media itself (sand, silt, composition, etc.) as an inhibitor to dissociation,
- Undertake permeability studies on hydrate cores before and after decomposition,
- Observe phase behavior with the injection of solvents, inhibitors and solvent/inhibitor combinations,
- Determine phase behavior inside a core and how this may or may not differ from the behavior of pure hydrate, and
- Determine how methanol injection effects hydrate equilibrium conditions.

Much of this work was recognized to be breaking new ground. While a significant amount of previous work had been conducted on pure component phase equilibrium measurements, very little had been done related to heat transfer, thermal conductivity and heat capacity measurements of methane hydrates. Some attempts had been made to develop simple hydrates in porous media systems, but work on simulated cores was only in the initial stages. Accordingly, the objectives set out were to be achieved by:

- Developing simulated methane hydrate cores in the laboratory to closely approximate naturally occurring systems,
- Developing techniques to simulate methane hydrates under *in situ* pressure and temperature conditions (most work to date had been on non-methane systems), and
- Obtaining cores of actual hydrate under *in situ* conditions.

The question of how to determine the presence of hydrates prior to drilling at offshore locations was seen to require an improvement in seismic-based methods of identification. The approach was to be through new, improved high resolution seismic, both reflection and refraction methods, with the sources and the detectors on the sea floor. The potential need for laboratory studies to provide velocity and sonic information to aid in interpretation was also identified.

The question of how to determine the presence of hydrates during drilling operations at offshore locations was also recognized as important. The approaches to upgrading existing methods for detection were defined as: pre-bit push probes that could be used to measure mechanical, chemical and temperature properties of the sediment, and the application of new (at the time) logging techniques such as Nuclear Magnetic Resonance (NMR), carbon-oxygen, or chloride logs. The need for the development of a pressure core barrel that would allow for the maintenance of a core at close to *in situ* temperature was seen as a necessary prerequisite to being able to provide a complete physical, chemical and geological description of a hydrate core.

The question of how to determine the presence of hydrates prior to drilling at onshore locations was seen to require confirmation of the efficacy of both seismic and electrical logging tools. The recommended approach was to establish a cooperative relationship with industry on the Alaska North Slope and establish the Kuparuk Field as a location for collecting and preserving cores, logs and seismic data. Improvements in methods of gathering and interpreting the data were to be supported by the laboratory tests.

Ultimately, a field test laboratory at Kuparuk was seen as being necessary to develop and validate new coring and logging tools that would permit the collection of data to support the mapping of the extent of the onshore Arctic hydrate resource.

The question of how to determine the best techniques for producing methane from hydrates was seen to hinge on identifying the reservoir properties needed for applying either pressure reduction or thermal stimulation. These properties were defined as:

- Gas content (porosity and pore content),
- Mechanical properties,
- Permeability (both hydrated and hydrate-free reservoir), and
- Heat conduction properties.

Thermal stimulation was seen as a likely alternative for dissociating gas hydrate as part of a production scheme. As such, it was recognized that understanding the speed at which a thermal front propagates through a reservoir rock, a function of both conduction and convection, was important. Permeability was also recognized as critical, as well as mechanical properties, in light of the fact that fracturing might be required to deliver thermal fluids and produce dissociated gas.

In the case of pressure reduction as an alternative scheme for dissociating the hydrate, permeability was recognized as the most important property. Also, the influence of groundwater systems in maintaining pressure would need to be defined.

Finally, understanding how the distribution of hydrate within the sediments (evenly distributed within a reservoir-quality rock, layered with shale or sand, or massive layers) would affect production was also recognized as critical to developing a rationale for any type of production scheme. Characterizing this distribution could be accomplished by a combination of conventional techniques (geophysics, well testing, well logging).

R&D focused on the production of gas hydrates was seen as requiring both laboratory and field program elements. The laboratory program would include production of synthetic hydrated “cores” in order to perform lab analyses of hydrate systems. The recovery and testing of natural core was also seen as critical to obtaining an accurate characterization of the actual hydrate/sediment system (or systems). The top priorities of the field program were seen to be:

- Recovery of natural core for the measurement of hydrate/sediment properties and the correlation of core data with log and seismic data, and
- Testing of various production alternatives.

The acquisition of core from an onshore hydrate site was considered more likely than a marine site, due to the lower risk and larger amount of activity underway in the Arctic at the time.

The results and recommendations of the Workshop informed the structure and areas of focus for the program that was carried out beginning in 1983. The bulk of more than $8 million in methane hydrate research funds were expended from 1984 through 1986, but work continued on a number of projects through 1992. Large-scale DOE funding of methane hydrate research ended at that time and did not resume until 1999.

3.5.3. Program Design

The 1983-1992 Methane Hydrate research program was designed to evaluate the potential of gas hydrates as a future supply of gas, to validate the extent of the resource, to estimate the potential resource and to develop methane hydrate exploration and production technology to the proof-of-concept level. Specific objectives were to:

- Assess the current state of technology,
- Determine the chemical and physical properties of both natural and synthetic gas hydrates,
- Develop the geologic characterization of and geologic models for the formation of both onshore and offshore gas hydrates,
- Develop resource estimates of both onshore and offshore gas hydrates
- Develop the necessary diagnostic techniques and methods for measuring the in-place characteristics of both onshore and offshore gas hydrates, and
- Develop strategies, reservoir and stimulation models, and preliminary economics for gas hydrate production.

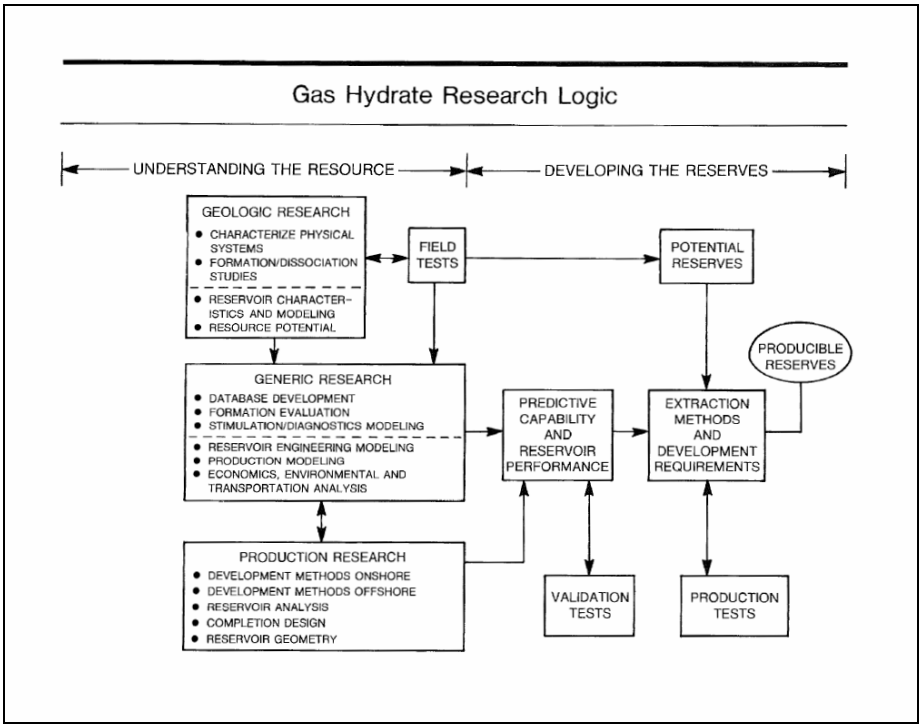

Figure 3.5.1: Gas Hydrate Research Program Schematic.

In pursuit of these objectives, the gas hydrate research program was comprised of three technical elements and a project management function (Figure 3.5.1). The technical elements included Geologic Research, Generic Research, and Production Research.

The Geologic Research element focused on mapping, characterization and analyses of geological deposits existing within the hydrate stability zone in both onshore and offshore areas. Studies were undertaken to determine the factors that permit or prohibit the formation and dissociation of gas hydrates in the subsurface. The plan was for these analyses to generate data to guide more detailed, site-specific research required for the development of reservoir diagnostics, stimulation design and eventual estimates of the recoverable gas reserves associated with gas hydrates. The work in this area would both inform the design of field tests and benefit from the data collected.

Generic Research was limited to database development and laboratory studies defining the fundamental properties of gas hydrates. These studies, along with both geophysical and geochemical analyses, were to provide the necessary data to identify features that could aid industry in locating hydrate deposits and in defining hydrate reservoir geometry. This research also had a significant modeling component that incorporated the understanding acquired through laboratory studies.

Production Research was focused primarily on the modeling and development of techniques for producing gas from hydrates at onshore and marine locations (thermal fluid injection to stimulate production was expected to be a likely approach). Preliminary development of a hydrate-production well design was also undertaken.

The logic was for the results of the Generic and Production Research elements to combine to form a predictive capability for reservoir performance that could be validated with field tests. This capability would inform the design of extraction methods which could also be validated with production tests. The combination of results from these efforts with the maps of potential resource areas would lead to one of the ultimate goals of the program: estimates of producible reserves.

3.5.4. Major Contracted Gas Hydrates Projects

Listed below are the key projects undertaken during the 1983-1992 time frame. The primary Project Manager for the Methane Hydrate program during this time period was the late Rodney D. Malone. Also acting as a Project Manager for portions of the work was William Lawson.

Geochemical and Geologic Factors Effecting the Formulation of Gas Hydrate
Contract: DE-AI21-83-MC20422
Performer: U.S. Geological Survey (Menlo Park, CA)
Key Investigators: Keith Kvenvolden, G.E. Claypool
Time Period: Oct. 1983 – Sept. 1987
Objectives: The broad objectives of this project were to:

- Evaluate geochemical and geological conditions at sites where high methane concentrations and gas hydrates are found,
- Determine factors controlling generation and accumulation of methane in gas hydrates,
- Make regional and worldwide syntheses of marine gas hydrate occurrences, and
- Develop predictive models for gas hydrate occurrence in oceanic sediment.

The approach was to:

- Review geophysical evidence for marine gas hydrate occurrence,
- Participate in oceanographic and deep sea drilling expeditions to collect samples of suspected marine gas hydrates,
- Characterize known sedimentary occurrences of gas hydrates or high methane contents by a standard suite of geochemical analyses,

- Perform controlled decomposition experiments on naturally occurring or artificially synthesized gas hydrates,
- Review and synthesize the geological and geochemical factors associated with marine gas hydrate occurrence,
- Develop a kinetic model of microbial methanogenesis with geological factors as input parameters which predicts the amount and isotopic composition of methane formed, and
- Use the model in conjunction with marine geology to predict sites favorable for, and the potential worldwide extent of, marine gas hydrates.

Geologic Interrelations Relative to Gas Hydrates within the North Slope of Alaska
Contract: DE-AI21-83-MC20422
Performer: U.S. Geological Survey (Menlo Park, CA)
Key Investigators: Tim Collett, Kenneth Bird, Keith Kvenvolden, Myung Lee, L.A. Beyer, A.H. Lachenbruch, L.B. Magoon
Time Period: Oct. 1983 – Sept. 1990
Objectives: There were two parts to this project: Phase I (Task 6) and Phase II (Task 18). Task 6 dealt with the evaluation of existing data in an attempt to delineate gas hydrate occurrences in northern Alaska and to evaluate the physical properties controlling gas hydrate distribution. Task 18 activities were a continuation of Phase I, except that the major emphasis was to obtain new data through an active field study program. The field research included temperature and borehole gravity surveys, formation water sampling and analysis, and geologic/geochemical sampling and analysis of wells and outcrops.

Task 6 objectives were:

- Define and evaluate possible gas hydrate reservoirs,
- Evaluate geologic/geochemical controls on gas hydrate occurrences,
- Develop a model for terrestrial gas hydrate formation,
- Conduct a gas hydrate resource estimate, and
- Select a coring site to study gas hydrate.

Task 18 objectives were:

- Collect and analyze geologic/geochemical samples relative to gas hydrates,
- Conduct precision temperature surveys to determine: 1) equilibrium formation temperatures; 2) limits of the gas hydrate stability and permafrost regions; 3) geothermal gradients and heat flow; and 4) possible *in situ* thermal indications of gas hydrate occurrences,

- Conduct borehole gravity surveys to detect gas hydrate, determine reservoir porosity and provides density measurements to better understand thermal properties,
- Characterize formation water chemistry, and
- Model the seismic character of *in situ* gas hydrates.

Measurement of In Situ Hydrate Dissociation Properties
Contract: DE-AC21-83MC20693
Performer: Colorado School of Mines (Golden, CO)
Key Investigators: Dendy Sloan, M.S. Selim, Roger Reuff
Time Period: Sept. 1983 – Jan. 1986
Objectives: The broad goals of this project were: (1) to measure the dissociation rate of natural gas hydrates, and (2) to formulate a rigorous mathematical model which fits the measured dissociation rate and which includes the properties measured. Specific objectives included:

- Evaluation of the hydrates recovered from the Glomar Challenger drill ship during an expedition to the Mid-America Trench,
- Measurement of the heat capacity and heat of dissociation of the hydrates, using a modified differential scanning calorimitry (DSC) technique,
- Construction of an electrobalance apparatus to measure the dissociation rates of hydrates, including pressure, temperature and mass change with time, and
- Formulation of a rigorous mathematical model for hydrate dissociation, which would incorporate the properties measured and match the rates measured.

Handbook of Gas Hydrate Properties and Occurrence
Contract: DE-AC21-82MC19239
Performer: Lewin and Associates, Inc. (Washington, D.C.)
Key Investigators: Vello Kuuskraa, Edgar Hammershaimb
Time Period: 1983
Objectives: The objective of this project was to compile a handbook providing data on the resource potential of naturally occurring hydrates, the properties that were needed to evaluate their recovery, and their production potential. This included a review of published resource estimates and a listing of known and inferred occurrences, a compilation of physical and thermodynamic properties, and an explanation of their relevance, and an estimate of the net energy balance for recovering hydrates.

Evaluation of the Geological Relationships to Gas Hydrate Formation and Stability
Contract: DE-AC21-84MC21181
Performer: Geoexplorers International, Inc. (Denver, CO)
Key Investigators: Jan Krason, Patrick Finley, Marek Ciesnik
Time Period: Oct. 1984 – Sept. 1989

Objectives: The project investigated the relationship of geological environments on gas hydrate formation and stability by basin analysis of gas hydrate sites. Basin analyses were performed on 21 offshore locations with direct or indirect evidence of gas hydrates. Sediment composition, provenance and depositional history were documented and structural development of each sedimentary basin determined using drilling results and seismic reflection profiles. The potential for generation of biogenic methane and conventional thermogenic hydrocarbons was assessed using geochemical data and thermal modeling. All available seismic data, both published and unpublished, were examined for evidence of hydrates. BSRs and other seismic anomalies were mapped. Conditional assessments of gas resources were derived and quantities of gas contained in both gas hydrate and possibly trapped beneath the gas hydrate stability zone were estimated.

Gas Hydrates Thermomechanics
Contract: DE-AC21-84MC21180
Performer: University of Washington (Seattle, WA)
Key Investigators: R.C. Corlett
Time Period: June 1984 – Sept. 1987
Objectives: The objectives of this project were to: (1) to determine whether stress anisotropy significantly alters the decomposition pressure at exposed faces of gas hydrates specimens or the rate of decomposition at such faces, and (2) to quantify these effects for some specified anisotropic stress states for ideal and geologically realistic specimens.

Thermal Measurements on Structure I and Structure II Pure Clathrate Hydrates and on Natural Gas Samples
Contract: DE-AI21-84MC21089
Performer: National Bureau of Standards (Boulder, CO)
Key Investigators: Jane E. Callanan
Time Period: July 1985 – June 1986
Objectives: The objectives of this project were to determine the heat transfer and thermal conductivity values of both synthetic and natural gas hydrates through laboratory experiments and measurements. A secondary objective was to develop a model that permitted the stability of hydrates to be determined for various conditions of temperature, pressure and concentration.

Ground Movements Associated with Gas Hydrate Production in Geologic Media
Contract: DE-FG21-87MC24051
Performer: West Virginia University (Morgantown, WV)
Key Investigators: Hema J. Siriwardane
Time Period: Sept. 1987 – June 1989

Objectives: The primary objective of this research work was to evaluate the influence of hydrate production on ground movements near the wellbore and at the surface, using computer simulations of what would be expected in a hydrate reservoir during the production stage.

Ground Movements Associated with Gas Hydrate Production
Contract: DE-FG21-91MC28080
Performer: West Virginia University (Morgantown, WV)
Key Investigators: Hema J. Siriwardane, Bora Kutuk
Time Period: 1991 – 1992
Objectives: The primary objective of this research was to evaluate the influence of hydrate production on ground subsidence at the surface, using computer simulations of what would be expected in a hydrate reservoir during the production stage. This project built on the results of an earlier project focused on the same problem, by the same performer.

Development of Alaskan Gas Hydrate Resources
Contract: DE-FG21-86FE61114
Performer: University of Alaska
Key Investigators: Ghanahyam D. Sharma, Vidyadhar A. Kamath, S.P Godbole, S.L Patil
Time Period: Oct. 1986 – Sept. 1990
Objectives: The objectives were to:

- Gather data and information relevant to gas hydrates on the Alaskan North Slope, including geothermal gradient data, remote sensing data, permafrost depth and thickness data, seismic data, and oil and gas well locations,
- Review gas hydrate literature to compile information related to gas hydrate equilibrium data and predictive models, gas hydrate recovery models, and geologic occurrence of hydrates,
- Develop contacts within the petroleum industry in the State of Alaska to obtain access to logs, cores and water samples,
- Study the implications of dissociation of in situ gas hydrate deposits relative to drilling safety and subsidence,
- Conduct experimental and theoretical modeling work related to techniques for recovery of gas from hydrates (depressurization, hot water, brine, methanol, glycol and steam injection), including measurement of permeability changes during formation and dissociation of hydrates in porous media, and to
- Perform an experimental study of hydrate formation in the presence of Alaskan North Slope crudes to understand the inter-relationship between gas hydrate and heavy oil/tar sand resources.

Seismic Interpretation of Gas Hydrates in the Blake Ridge Area
Contract: DE-AI21-83-MC20422
Performer: U.S. Geological Survey (Reston, VA)
Key Investigators: Thomas Ahlbrandt, William Dillon
Time Period: Feb 1990 – Feb. 1991
Objectives: The objective of this project was to determine the amount of methane that is bound in gas hydrates in marine sediments, to understand the distribution of gas hydrates and to relate the amounts and distribution of hydrate to geological settings and geological/geochemical processes.

An Experimental Study of Hydrate Formation Rates
Contract: DE-AC21-85MC22221
Performer: University of Pittsburgh (Pittsburgh, PA)
Key Investigators: Gerald D. Holder
Time Period: 1985 – 1986
Objectives: The objective of this project was to measure the rate of hydrate formation above and below the ice point, and to determine at what rate hydrates in the earth can be expected to form and dissociate as the temperature in a zone containing gas and ice (or gas and water) changes, or as a zone containing water is contacted with methane.

Gas Hydrate Research in the Gulf of Mexico
Contract: DE-AC21-86MC23145
Performer: Columbia Gas System Service Corporation
Key Investigators: R. Bennett
Time Period: 1987 – 1990
Objectives: This project was designed to examine existing seismic and geochemical data from the edge of the continental shelf and from the continental slope in the Gulf of Mexico for evidence of hydrates. There were two Phases: I and II.

During Phase I, low and medium energy seismic data was examined for signatures that might establish a signature of hydrate zones per se, or an upper limit of an impervious gas hydrate cap. The data was also examined for permeable pathways in economic gas production areas which could be followed into deeper water where established signatures of gas hydrates could be identified on high energy seismic sections.

Geochemical data, which were generated concurrently on some of the low and medium energy seismic surveys, also were examined for information which might support any theories or concepts based on the geophysical data. The geochemical data included hydrocarbon analyses of water samples taken 30 feet above the sea floor and carbon isotope ratio analyses of gas samples from active underwater gas seeps.

High energy seismic sections shot on the continental slope were reviewed to identify any Bottom Simulating Reflectors (BSRs) that might be present, and permeable pathways were noted so that they could be related to permeable pathways recorded by low and medium energy seismic surveys.

Areas where sediments were too shallow to be in the hydrate zone but could possibly be charged with gas from a hydrate source, or where hydrates might exist in a metastable form, were also examined.

The purpose of Phase II was to make an inexpensive low and medium energy seismic survey in a known gas hydrate area to identify the top of a hydrate zone or characterize signatures that might indicate the upper limit of an impervious hydrate cap. Seismic data was collected at two areas in Garden Banks and three areas in Green Canyon.

Geological and Geochemical Implications of Gas Hydrates in the Gulf of Mexico
Contract: DE-FG21-84MC21088
Performer: Texas A&M University (College Station, TX)
Key Investigators: J.M. Brooks, W.R. Bryant
Time Period: 1984 – 1985
Objectives: The objectives of this project included:

- Identification of hydrate sites in deep water Gulf of Mexico sediments,
- Collection of physical samples of hydrates from deepwater locations in the Gulf of Mexico for use in laboratory analysis,
- Assessment of thermogenic versus biogenic nature of gas from hydrate locations in the Gulf of Mexico,
- Collection of shallow seismic data over identified hydrate sites and assessment of the relationship of seismic anomalies and subsurface structure,
- Evaluation of historical seismic records for evidence of potential hydrate-containing sediments in the northern Gulf of Mexico, and
- Chemical and isotopic characterization of hydrate core material.

Geology, Reservoir Engineering and Methane Hydrate Potential of the Walakpa Gas Field, North Slope, Alaska
Contract: DE-FG21-91MC28131
Performer: North Slope Borough (Barrow, AK)
Key Investigators: Richard K. Glenn, William W. Allen
Time Period: 1991 – 1992
Objectives: The objective of this study was to evaluate the methane hydrate potential of the Walakpa gas field, a shallow gas field located near Barrow, Alaska. Understanding

the reservoir potential and predicting the production characteristics of the Walakpa Field was to be accomplished by an analysis of the reservoir geology, production test data and field-scale geothermal studies.

The Sensitivity of Seismic Responses to Gas Hydrates
Contract: DE-FG21-91MC28079
Performer: New England Research, Inc. (White River Junction, VT)
Key Investigators: John E. Foley, Daniel R. Burns
Time Period: 1991 – 1992
Objectives: The objective of this project was to employ seismic modeling to improve understanding of the sensitivity of seismic amplitudes to the presence of gas hydrates in marine sediments.

3.5.5. Methane Hydrate Research Efforts of METC's In-House Organization

METC's in-house research organization carried out a number of research efforts, independently and in concert with academic laboratories, designed to complement the work being conducted by the contractors listed above.

An important contribution of METC's in-house methane hydrate research group (part of the Geoscience Research Branch) was the development of a number of techniques for forming methane hydrates in the laboratory (so-called "synthetic hydrates"), several of which are still used today. The group also carried out tests on natural hydrates and made their results public; of the six laboratories that received samples of the Deep Sea Drilling Program's massive hydrate core recovered in the Mid-Americas trench in 1982, METC was one of only two that actually made their laboratory results public.[3]

The hydrate modeling of Burshears and others working in METC's modeling group was innovative at the time and METC attempted to verify it using laboratory experiments; an effort that was at least qualitatively successful. [4]

The METC in-house hydrates group served a critical role in integrating and coordinating work among all the program participants. Representatives also participated in two Gulf of Mexico hydrate recovery cruises with Texas A&M (partially funded by DOE) and

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[3] Lawson, W.F., S.M. Reddy, L.A. McCarthy, C.E. Gregoire, K.L. Vassallo, and D.A. Barlow, "Acoustic Velocity and Electrical Property Measurements in the DSDP Methane Hydrate Core," AIChE Winter National Meeting, March 12, 1984, Atlanta, Georgia.
[4] Burshears, M., et al., "A Multi-Phase, Multi-Dimensional, Variable Composition Simulation of Gas Production From a Conventional Gas Reservoir in Contact With Hydrates," Presentation at the Unconventional Gas Technology Symposium of the Society of Petroleum Engineers held in Louisville, Ky., May 18-21, 1986 (SPE 15246, pp. 449-456).

recovered hydrate samples which were brought back for analysis. Further analysis was undertaken in collaboration with the National Research Council of Canada.[5,6]

The American Chemical Society's Third Chemical Congress of North America, held in Toronto, Canada, on June 5-10, 1988, included a "Gas Hydrates Symposium" organized by William Lawson of METC. Fifteen of the twenty-three papers submitted for this meeting were from METC contractors or in-house researchers (Table 3.5.1). Generally, METC published reports summarizing research results only if the work was not published in a refereed publication or accepted as a presentation at a significant meeting. Accordingly, these papers represent a good portion of the public record of in-house methane hydrate research at METC during this time period.

3.5.6. Highlights of Important Results

Although the level of funding for this Methane Hydrates Program at DOE did not reach the levels originally envisioned when the Program was designed, a number of important objectives were achieved. These included:

- Creation of a framework of basic knowledge about the distribution and physical/chemical nature of naturally occurring methane hydrates,
- The initiation of a collaborative gas hydrates research effort among industry, national labs, academic institutions and multiple Federal agencies that continues to the present day,
- The establishment of the existence of hydrates in the Kuparuk Field, of the North Slope of Alaska,
- Comprehensive studies of 15 offshore hydrate basins (Krason Reports),
- Preliminary estimates of gas-in-place for hydrate deposits,
- Preliminary production models for depressurization and thermal production of gas from hydrates; and
- Creation of the gas hydrate and sediment test lab instrument (GHASTLI) at the USGS., the first device capable of simulating deep-sea conditions to allow testing of hydrate-bearing sediments.

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[5] Davidson, D.W., S.W. Gary, S.R. Gough, Y.P. Handa, C.I. Ratcliffe, J.A. Ripmeister, J.S. Tse, K. Sinque, and W.F. Lawson, "The Physical Chemistry of a Naturally-Occurring Hydrate of Natural Gas," presented at the Symposium on Energy Related Chemistry, Division of Physical Chemistry, Canadian Institute of Chemistry at Queen's University, Kingston, Ontario, June 2-5, 1985.

[6] Davidson, D.W., S.K. Garg, S.R. Gough, Y.P. Handa, C.I. Ratcliffe, J.A. Ripmeester, J.S. Tse and W.F. Lawson, "Laboratory Analysis of a Naturally Occurring Gas Hydrate from Sediment of the Gulf of Mexico," Geochimica et Cosmochimica Acta, Vol. 50, 1986.

The Krason Geoexplorer reports still stand as the only studies (broad as they were and often data poor) of hydrate occurrences in some parts of the world. It was a massive undertaking and at the time a very important contribution to the hydrate literature.

The DOE funding of the USGS made possible some very significant contributions in Alaska, as part of the Deep Sea Drilling Program and as part of other marine efforts to find and sample hydrates. Along with the USGS, Texas A&M also accomplished significant work defining both the occurrences in the Gulf of Mexico and delineating how they were different from other marine occurrences.

Table 3.5.2 provides a list of key reports that contain the most important results associated with DOE methane hydrate research projects. These reports, as well as a number of other associated technical notes, interim reports, topical reports and proceedings have been collected on the accompanying CD.

3.5.7. Subsequent Developments in Methane Hydrate Research

In 1992, the 10-year, eight million dollar program was terminated as government policy shifted from long-term, high-risk R&D to near-term exploration and production R&D. Although DOE funding ceased, work continued at USGS, NRL, NSF, ODP, universities, other laboratories, and overseas. The 1995 studies of the Blake Ridge, as part of the ODP Leg 164, contributed significantly to the understanding of hydrates.

In 1991 and 1994, DOE sponsored the International Conference on Methane Hydrate R&D so hydrate researchers from all over the world could share results and problems.

DOE's Natural Gas Supply Program provided a small amount of funding in Fiscal Year (FY) 1997 and FY 1998 to support activities in anticipation of the initiation of a new program of methane hydrate research in FY 1999. These activities included: (1) participation in the production testing and sample analysis of a 1,200-meter deep well in the Mackenzie Delta, Canada, drilled by Japan National Oil Company (JNOC); (2) processing and evaluating seismic data in hydrates regions of the Gulf of Mexico; (3) design of a global database of gas hydrates and related gas deposits; and (4) participation in an industry/university gas hydrates consortium.

The startling success of international drilling programs targeting methane hydrates in Canada and Japan indicated that the commercial exploitation of methane hydrates might be possible sooner than previously thought. DOE began planning for a renewed, multi-agency, national, gas hydrates program. A National Methane Hydrates Program was developed through the cooperative efforts of a multi-agency task force that included representatives of agencies and government entities, and academic institutions, many of

which had been actively involved in the work carried out between 1982 and 1993. The goals for this second phase of research, identified in two workshops in 1998, focused on four areas:

1. Resource characterization,
2. Drilling safety and sea floor stability,
3. Global climate change, and
4. Methane production from hydrates.

A report by the task force titled "A Strategy for Methane Hydrates Research and Development" published in August of 1998 laid out a new plan for meeting these goals.

Recognizing the need for coordinated effort, Congress and the President of the United States enacted Public Law 106-193, the Methane Hydrate Research and Development Act of 2000, in May of that year. The bill called for the Secretary of Energy to begin a new methane hydrate R&D program in consultation with the U.S. Departments of Commerce (DOC)—represented by the National Oceanic and Atmospheric Administration (NOAA), Department of Defense (DoD)—represented by the Naval Research Laboratory (NRL), the Department of the Interior (DOI)—represented by the Minerals Management Service (MMS) and the U.S. Geological Survey (USGS) and now also the Bureau of Land Management (BLM), and the National Science Foundation (NSF).

The legislation directed these organizations to collaborate on a program to make agreements with universities and companies through a competitive process to:

- Conduct basic and applied research to identify, explore, assess, and develop methane hydrates as a source of energy;
- Develop technologies for efficient and environmentally sound development of methane hydrate resources;
- Promote education and training in methane-hydrate science;
- Conduct basic and applied R&D to assess and mitigate the environmental impacts of hydrate degassing (both natural and that associated with development);
- Develop technologies to reduce the risks of drilling through methane hydrates, and
- Conduct exploratory drilling in support of the above activities.

On August 8, 2005, President Bush signed the Energy Policy Act of 2005, which provided an amendment to the Methane Hydrate Research and Development Act of 2000 and extended funding for methane hydrate R&D through 2010. The wording of the Energy Policy Act called on the Secretary of Energy to continue to carry out the activities directed by the National Methane Hydrate R&D Act (listed above), and in addition specifically directs that the Program:

- Identify methane hydrate resources through remote sensing;
- Acquire and reprocess seismic data suitable for characterizing methane hydrate accumulations;
- Offer fellowships or other means for graduate education and training; and
- Conduct production testing operations on permafrost and non-permafrost gas hydrates, including drilling of one or more full-scale production test wells.

The Secretary of Energy was directed to report annually to Congress on the results of actions taken to carry out this Act, and as with the previous legislation, the National Research Council (NRC) was tasked with preparing a report on the progress made by the program and submitting recommendations for future methane hydrate R&D needs for the Secretary of Energy to deliver to Congress before September 30, 2009.

The work performed by the researchers involved in the 1982-1992 program provided a strong foundation for these new initiatives. Indeed, many of the institutions and several of the individuals involved in the current program were also involved in the earlier effort.

Table 3.5.1: Papers from DOE-Supported Research Presented at the "Methane Hydrates Symposium" of the Third Chemical Congress of North America, June 1988.

Title	Authors	Organization
Mechanical Properties of Gas Hydrates in Unconsolidated Media	H.J. Siriwardane and W.F. Lawson	U. of West Virginia and DOE-METC
Production of Continuous Gas Hydrate Samples: A Technology Status Survey	R.C. Corlett, W.F. Lawson, and K.L. Dominic	U. of Washington and DOE-METC
Gas Hydrates in Sediment of the Peruvian Continental Margin	K. A. Kvenvolden, M. Kastner	USGS/Scripps Institution of Oceanography
Pore Water Geochemical Anomalies: Reliable Indicators of Gas Hydrate Presence?	P.D. Finley, K.L. Dominic	Geoexplorers International/ DOE-METC
Gas Hydrates in U.S. Continental Margin Sediments	J. M. Brooks, M.C. Kennicutt II, R.C. Pflaum	Texas A&M University
Evaluation of Geochemical and Geophysical Data for Gas Hydrate Exploration in the Gulf of Mexico	R. Bennett	Columbia Gas System
A Third Surface Effect on Hydrate Formation	H. Ouar, Suk-Bae Cha, A. Inserni, T.R. Wildeman, E.D. Sloan	Colorado School of Mines
Molecular Dynamics of Gas Hydrates	M. J. Hwang, G.D. Holder, A. Post	University of Pittsburgh
Review of Proposed Massive Gas Hydrate Formation Process	P. D. Finley, J. Krason	Geoexplorers International
Geological Environments of Gas Hydrates of the Black Sea	M. S. Ciesnik, J. Krason	Geoexplorers International
Petrographic Characterization of Hydrate Reservoirs in Northern Alaska	R.A. Smosna, T.H. Mroz	DOE-METC
Potential Gas Hydrate Reservoir on the Barrow Arch, Alaska	T. H. Mroz	DOE-METC
Gas Hydrate Resource Estimate, North Slope, Alaska	T.S. Collett	USGS
Measurement of Gas Permeability in Hydrate Saturate Unconsolidated Cores	S. L. Patil, P.N. Mutalik, V.A. Kamanth and S.P. Godbole	University of Alaska
Hydrate Formation in Crude Oils and Phase Behavior of Hydrates in Mixtures of Methane, Propane, Isobutane and N-Butane	S. G. Paranjpe, S.L. Patil, V.A. Kamanth, S.P. Godbole	University of Alaska

Table 3.5.2: List of Major Research Reports for Methane Hydrates Program (1982-1992).

Report Number	Title	Authors	Organization	Date
DOE/MC/22221-2210	An Experimental Study of Hydrate Formation Rates - Final Technical Report, August 1986	Holder, G.D.	University of Pittsburgh	1986 Aug
DOE/MC/23145-2616	Gas Hydrate Research in the Gulf of Mexico - Final Report, May 1988	Bennet, R.	Columbia Gas Service System Corp.	1988 May
DOE/MC/23145-2890	Gas Hydrate Research in the Gulf of Mexico, Phase II - Final Report, January 1990	Bennet, R.	Columbia Gas Service System Corp.	1990 Jan
DOE/MC/21180-2617	Gas Hydrates Thermomechanics - Final Report, April 1988	Corlett, R.C.	University of Washington	1988 Apr
DOE/MC/20422-2691	Geochemical and geologic factors effecting the formulation of gas hydrate: Task No. 5, Final report	Kvenvolden, K.A.; Claypool, G.E.	USGS	1988 Jan
DOE/MC/20422-2692	Geologic Interrelations Relative to Gas Hydrates Within the North Slope of Alaska - Task #6 - Final Report	Collett, T.S.; Bird, K.J.; Kvenvolden, K.A.; et al.	USGS	1988 Jan
DOE/MC/21088-1964	Geological and Geochemical Implications of Gas Hydrates in the Gulf of Mexico - Final Report	Brooks, J.M.; Bryant, W.R.	Texas A&M University	1985 Sep
DOE/MC/21181-1950-Vol.1	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 1. Basin analysis, formation and stability of gas hydrates in the Blake-Bahama Outer Ridge - US East Coast	Krason, J.; Ridley, W.I.	GeoExplorers Intl.	1985 Jun
DOE/MC/21181-1950-Vol.2	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 2. Basin analysis, formation and stability of gas hydrates in the Baltimore Canyon Trough and environs - US East Coast	Krason, J.; Ridley, W.I.	GeoExplorers Intl.	1985 Jun
DOE/MC/21181-1950-Vol.3	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 3. Basin analysis, formation and stability of gas hydrates of the W. Gulf of Mexico	Krason, J.; Finley, P.; Rudloff, B.	GeoExplorers Intl.	1985 Oct
DOE/MC/21181-1950-Vol.4	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 4. Basin analysis, formation and stability of gas hydrates in the Offshore of Newfoundland and Labrador	Krason, J.; Rudloff, B.	GeoExplorers Intl.	1985 Sep
DOE/MC/21181-1950-Vol.5	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 5. Gas hydrates in the Russian literature	Krason, J.; Ciesnik, M.	GeoExplorers Intl.	1985 Oct

Report Number	Title	Authors	Organization	Date
DOE/MC/21181-1950-Vol.6	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 6. Basin analysis, formation and stability of gas hydrates in the Panama Basin	Krason, J. ; Ciesnik, M.	GeoExplorers Intl.	1986 Mar
DOE/MC/21181-1950-Vol.7	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 7. Basin analysis, formation and stability of gas hydrates in the Columbia Basin	Finley, P. ; Krason, J.	GeoExplorers Intl.	1986 Mar
DOE/MC/21181-1950-Vol.8	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 8. Basin analysis, formation and stability of gas hydrates in the Northern California offshore	Krason, J. ; Ciesnik, M.S.	GeoExplorers Intl.	1986 Jun
DOE/MC/21181-1950-Vol.9	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 9. Basin Analysis, Formation and stability of gas hydrates of the Middle America Trench	Finley, P. ; Krason, J.	GeoExplorers Intl.	1986 Dec
DOE/MC/21181-1950-Vol.10	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 10. Basin analysis, formation and stability of gas hydrates of the Aleutian Trench and the Bering Sea	Krason, J. ; Ciesnik, M.	GeoExplorers Intl.	1987 Jan
DOE/MC/21181-1950-Vol.11	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 11. Basin analysis, formation and stability of gas hydrates in the Black Sea	Ciesnik, M.S. ; Krason, J.	GeoExplorers Intl.	1987 May
DOE/MC/21181-1950-Vol.12	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 12. Basin analysis, formation and stability of gas hydrates in the Beaufort Sea	Finley, P.D. ; Krason, J.	GeoExplorers Intl.	1988 Oct
DOE/MC/21181-1950-Vol.13	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 13. Basin analysis, formation and stability of gas hydrates of the Nankai Trough: Topical report	Ciesnik, M. ; Krason, J.	GeoExplorers Intl.	1989 May
DOE/MC/21181-1950-Vol.14	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 14. Basin analysis, formation and stability of gas hydrates in the Timor Trough	Finley, P.D. ; Krason, J.	GeoExplorers Intl.	1989 Oct

Report Number	Title	Authors	Organization	Date
DOE/MC/21181-1950-Vol.15	Geological evolution and analysis of confirmed or suspected gas hydrate localities. Volume 15. Eval. of Geological Relationships to Gas Hydrate Formation and Stability Summary Report	Finley, P.D. ; Krason, J.	GeoExplorers Intl.	1989 Nov
DOE/MC/28080-3379	Ground Movements Associated With Gas Hydrate Production - Final Report, March 1992	Siriwardane, H.J. ; Kutk, B.	West Virginia University	1992 Mar
DOE/MC/24051-2808	Ground Movements Associated With Gas Hydrate Production in Geologic Media - Final Report	Siriwardane, H.J. ; Tsai, W.S.	West Virginia University	1989 Jun
DOE/MC/19239-1546	Handbook of gas hydrate properties and occurrence	Kuustraa, V.A. ; Hammershaimb, E.C.	Lewin and Associates, Inc.	1983 Dec
DOE/MC/20693-1995	Measurement of in-situ hydrate dissociation properties - Final Technical Report, Oct 1983 - Oct 1985	Sloan, E.D. ; Selim, M.S.	Colorado School of Mines	1985 Dec
DOE/MC/20422-2968	Natural Gas Hydrates on the North Slope of Alaska - Final Report, January 1991	Collett, T.S.	USGS	1991 Jan
DOE/MC/28079-92/C0029	The Sensitivity of Seismic Responses to Gas Hydrates - Final Report, August 1992	Foley, J.E. ; Burns, D.R.	New England Research, Inc.	1992 Aug
DOE/MC/19239-1422	Conceptual models for gas hydrates. Phase I. Technical Directive 6. Final Report	Kuuskraa, V. ; Hammershaimb, E. ; Sawyer, W.	Lewin and Associates, Inc.	1983 Jun
DOE/FE/61114--3031	Development of Alaskan gas hydrate resources. Final report	Kamath, V.A. ; Sharma, G.D. ; Patil, S.L.	1991 Jun 01	1991 Jun
DOE/MC/20013-T7	Laboratory analysis of gas hydrate cores for evaluation of reservoir conditions. Final Report	Holder, G.D.		1984 Jun
DOE/MC/28131-92/C0028	Methane hydrate potential and development of a shallow gas field in the arctic: The Walakpa Field North Slope Alaska	Glenn, R.K.	North Slope Borough	1992 Jan

3.6. Secondary Gas Recovery (1987-1995)

In 1992 the National Petroleum Council estimated that a resource base of 1,295 trillion cubic feet (Tcf) of technically recoverable natural gas resources (including proved reserves, conventional resources, and non-conventional resources) existed in the United States. Of that resource base, 216 Tcf was determined to be recoverable through *reserve appreciation* in existing fields in the lower 48 states. Reserve appreciation is the increase in estimated reserves over original field estimates as enhanced geological understanding and improved production technologies are developed and applied. The integrated application of concepts and cost-effective technologies from the disciplines of geology, engineering, geophysics, and petrophysics are required for converting these resources into producible reserves.

Natural gas reserve appreciation in conventional reservoirs has multiple components. Historically, field extensions through offset development well drilling and deeper pool drilling have been the way to add reserves. Recompletions of existing wells were often made without the benefit of a complete understanding of the reservoir's heterogeneity or compartmentalization. Where significant geologic variation occurs, incompletely drained or bypassed reservoir compartments remain to be drained by new infield drilling or strategically placed recompletions (Figure 3.6.1). In the last two decades, characterization of the internal geometry of reservoirs has revealed a much higher degree of compartmentalization than previously recognized. This compartmentalization (other than structural compartmentalization) is primarily a function of the depositional system and, secondarily, of the diagenetic history of the reservoir after deposition.

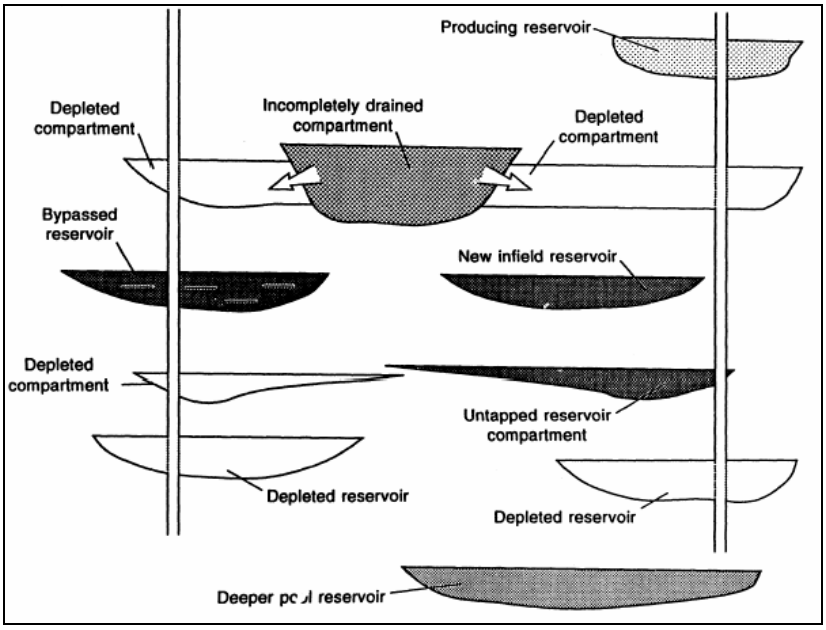

Figure 3.6.1: Schematic of Reservoir Compartmentalization.

The Secondary Natural Gas Recover (SGR): Targeted Technology Applications for Infield Reserve Growth was a joint venture research project sponsored by the U.S. Department of Energy (DOE), the Gas Research Institute (GRI), the State of Texas through the Bureau of Economic Geology at The University of Texas at Austin, and the natural gas industry. DOE leveraged $8.5 million in federal funding with $6.5 million from GRI, $1 million from Texas and $6.3 million from industry to support a 5-year proof-of-concept project. The SGR project was a field-based program employing a multidisciplinary approach that integrated geology, geophysics, engineering, and petrophysics. A major objective of this research project was to develop, test, and verify those technologies and methodologies that would have near- to mid-term potential for maximizing recovery of gas from conventional reservoirs in known fields. The new technologies to be developed and applied included 3-D seismic and vertical seismic profiling. The Bureau of Economic Geology at the University of Texas led the SGR team and coordinated the research, first in the onshore Texas Gulf Coast Basin and then in the Ft. Worth Basin.

3.6.1. Key Objectives and Program Design

The first part of the SGR project focused on reservoirs of the Gulf Coast Basin; data-rich, field-based models well-suited for evaluating infield development. The SGR research program focused on sandstone-dominated natural gas reservoirs in fluvial-deltaic plays within the onshore Gulf Coast Basin of Texas (Figure 3.6.2).

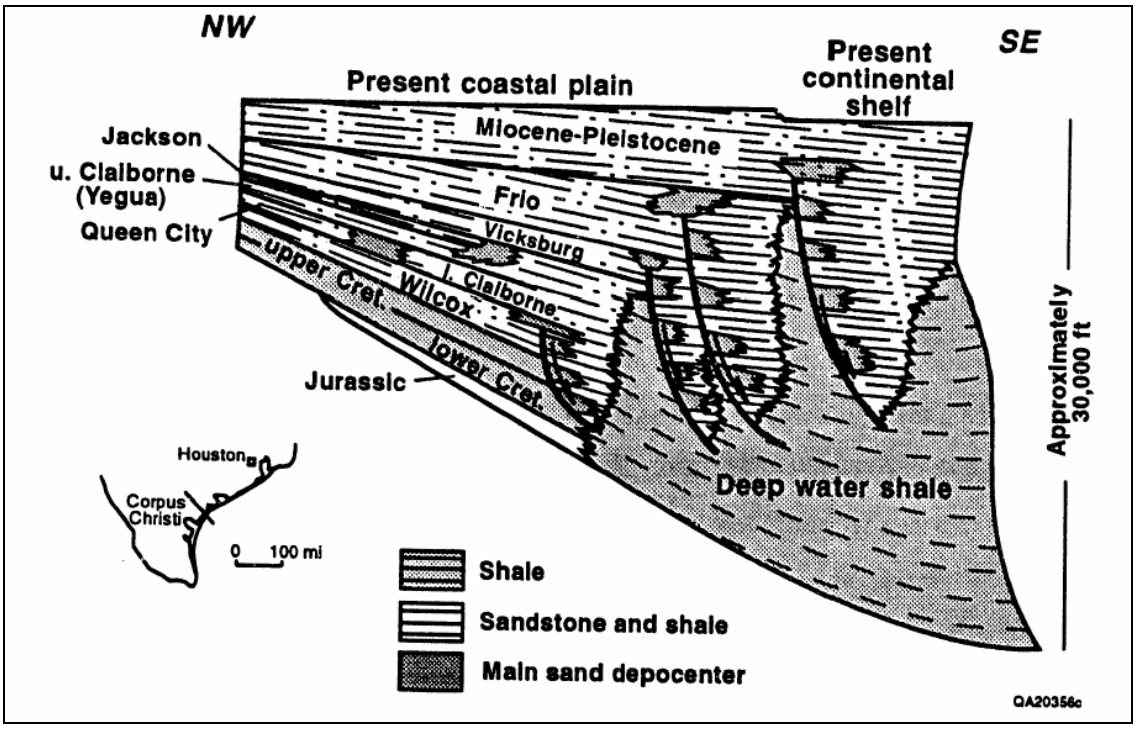

Figure 3.6.2: Schematic Depositional Dip-Oriented Cross-Section through the Central Texas Gulf Coast Basin, Illustrating the Relative Position of Major Sand Depocenters (Hardage, et al, 1995).

The primary project research objectives were:

- To establish how depositional and diagenetic heterogeneities cause, even in reservoirs of conventional permeability, reservoir compartmentalization and hence incomplete recovery of natural gas,
- To document examples of reserve growth occurrence and potential from fluvial and deltaic sandstones of the Texas Gulf Coast Basin as a natural laboratory for developing concepts and testing applications, and
- To demonstrate how the integration of geology, reservoir engineering, geophysics, and well log analysis/petrophysics leads to strategic recompletion and well placement opportunities for reserve growth in mature fields.

Geologic and engineering screening of 14 major gas fields in the onshore Gulf Coast Basin indicated that leading candidate gas fields in southeast, south-central, and South Texas included Lake Creek, Seeligson, Stratton-Agua Dulce, and McAllen Ranch fields. The fields were selected by applying a methodology developed by the project for the geological and engineering screening of sandstone reservoirs. Geologic and engineering

analyses of publicly available and industry-supplied data helped to define those gas fields that were suitable as a natural laboratory for project research.

Screening of heterogeneous fluvial-deltaic reservoirs of South Texas defined the first areas of field data collection and formed a major part of early phases of the project. Producing intervals are fluvial reservoirs in the Frio Formation (Seeligson and Stratton-Agua Dulce fields) and deltaic reservoirs in the Wilcox (in Lake Creek field) and in the Vicksburg (in McAllen Ranch field). Results obtained from the initial project phase formed the basis for technical presentations to industry representatives and stressed the potential benefits of cooperating with the Secondary Gas Recovery project. These presentations led to cooperative studies in four Gulf Coast fields.

Cooperative data analyses were initiated with Shell Western Exploration and Production Inc. (SWEPI) in 1989 at McAllen Ranch field in South Texas, which is part of the gas play known as Vicksburg Deltaic Sandstone in the Rio Grande Embayment. In 1990 and 1991, cooperative data were obtained from Mobil Exploration and Producing U.S., Inc., in Lake Creek field, which is part of the Wilcox Deltaic Sandstone in the Houston Embayment. Project research focused on integrating geologic, engineering, and formation evaluation of fluvial-dominated deltaic deposits in the lower Wilcox group. Both Stratton and Seeligson fields were candidates for detailed investigations within the Frio Fluvial-Deltaic Sandstones along the Vicksburg Fault Zone gas play. Seeligson field was the first SGR research field study site in the Frio Formation. Starting in mid-1990, with the cooperation of Union Pacific Resources Corporation, the SGR project focused its research efforts on quantifying secondary gas resources in middle Frio gas reservoirs in Stratton field in Nueces, Kleberg, and Jim Wells Counties, Texas.

In 1992 and 1993, an assessment of technical applications and economic feasibility of SGR approaches in small-scale application (mini-evaluations) were conducted to track the benefits and results. In cooperation with independent gas producers, an analysis of the development and operations to find and produce secondary gas reserves was evaluated in two separate field areas.

The second focus area of the SGR project was the Fort Worth Basin of North Texas (Figure 3.6.3). This assessment of Midcontinent sandstone natural gas reservoirs in Boonsville field integrated four key disciplines: geology, geophysics, reservoir engineering and petrophysics. The entire Atoka Group (Lower and Upper) in the project area was divided into 13 third-order genetic stratigraphic sequences (the first public comprehensive genetic sequence analysis to relate these prolific Pennsylvanian gas reservoirs to their seismic response and gas productivity). A 26 square mile 3-D seismic survey was acquired and interpreted to test methods for delineating reservoirs in thin-bed, hard-rock environments. Reservoir facies frameworks, assessed by integrating geological

and geophysical approaches, were combined with engineering and petrophysical evaluations of produced gas volumes and reservoir quality.

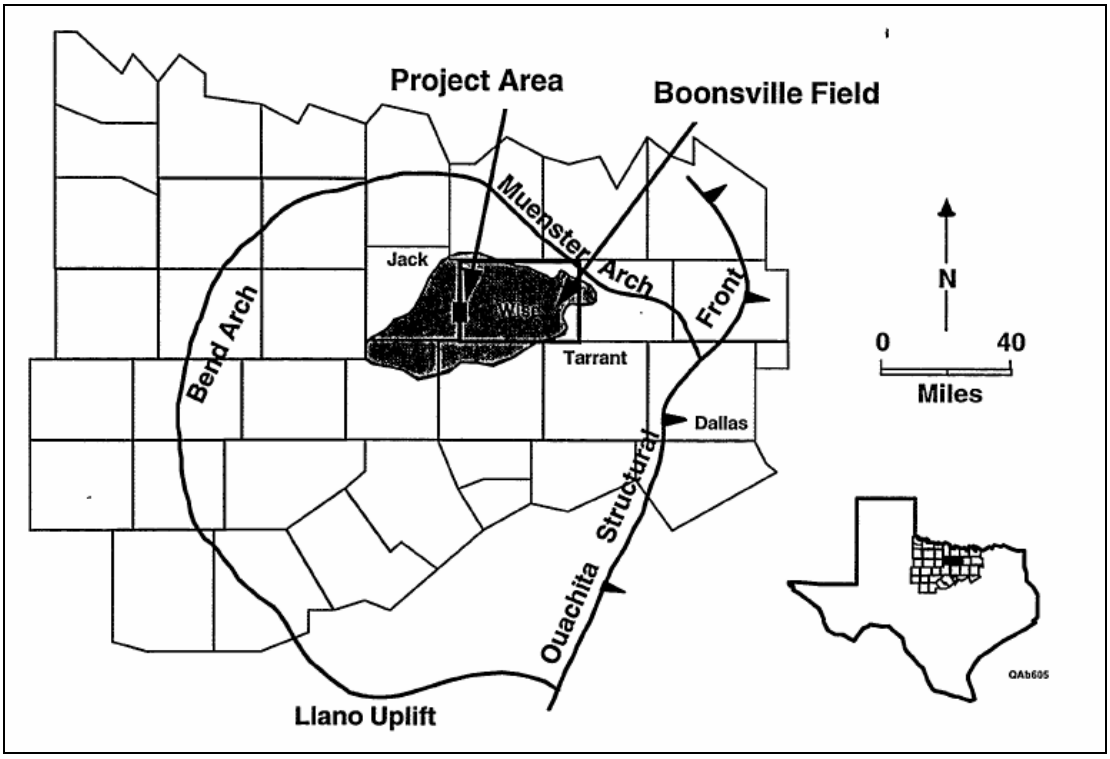

Figure 3.6.3: Location of the Boonsville Field in the Fort Worth Basin. The solid rectangle indicates where the large majority of data was collected.

3.6.2. Major Projects

There was only one major project funded under this program. The performer was the Bureau of Economic Geology at the University of Texas at Austin, under DOE contract DE-FG21-88MC25031. The effort was divided into three main elements.

Targeted Technology Applications for Infield Reserve Growth – A Synopsis of the Secondary Natural Gas Recovery Project Research, Gulf Coast Basin
Contract: DE-FG21-88MC25031
Performer: Bureau of Economic Geology at the University of Texas at Austin
Key Investigators: Raymond A. Leavey, Robert J. Finley, Bob A. Hardage
Time Period: Sept 1988 – April 1993
Objectives: The broad objectives of this project were to:

- Establish how depositional and diagenetic heterogeneities cause reservoir compartmentalization and lead to incomplete recovery of natural gas,
- Document examples of reserve growth occurrence and potential from fluvial and deltaic sandstones of the Texas Gulf Coast Basin, and
- Demonstrate how the integration of geology, reservoir engineering, geophysics, and well log analysis/petrophysics can lead to recompletion and well placement strategies for reserve growth in mature fields.

Secondary Natural Gas Recovery: Targeted Applications for Infield Reserve Growth in Midcontinent Reservoirs – Boonsville Field, Fort Worth Basin, TX
Contract: DE-FG21-88MC25031
Performer: Bureau of Economic Geology at the University of Texas at Austin
Key Investigators: Bob A. Hardage, David L. Carr, Robert J. Finley, Noel Tyler, David E. Lancaster, Robert Y. Elphick, James R. Ballard
Time Period: May 1993 – June 1995
Objectives: The broad objectives of this project were to define undrained or incompletely drained reservoir compartments controlled primarily by depositional heterogeneity in a low-accommodation, cratonic Midcontinent depositional setting, and afterwards, to develop and transfer to producers strategies for infield reserve growth of natural gas. Two specific activities were:

- To perform integrated geologic, geophysical, reservoir engineering and petrophysical evaluations of complex and difficult-to-characterize fluvial and deltaic reservoirs in the Boonsville Field (Bend Conglomerate Gas), a large mature gas field in the Fort Worth Basin of North Texas, and
- To demonstrate to industry approaches for overcoming reservoir complexity using state-of-the-art technologies being applied by a large cross-section of Midcontinent operators.

Integrated Strategies for Carbonate Reservoir Reserve Growth: an Example from the Ellenburger Group, Permian Basin, West Texas
Contract: DE-FG21-88MC25031
Performer: Bureau of Economic Geology at the University of Texas at Austin
Key Investigators: Bob A. Hardage, R.P. Major
Time Period: August 1995 – March 1998
Objectives: The broad objectives of this project were to provide a guide to results of research into the use of modern multidisciplinary analyses, including advanced analysis of modern 3-D seismic data, to establish procedures for gas reserve growth in complex carbonate reservoirs of West Texas.

Key reports related to the SGR program are detailed in Table 3.6.1.

3.6.3. Major Results

Results from the SGR program indicated that:

- Significant natural gas reserve appreciation opportunities exist where reservoirs are heterogeneous and compartmentalized.
- Such compartmentalization, other than structural, is depositional and/or diagenetic in origin and can be defined through a geologically centered approach to understanding reservoir flow units.
- Concept-driven integration of the four fundamental geo-scientific disciplines (geology, engineering, geophysics, and formation evaluation) is crucial to recognizing and exploiting reserve growth opportunities.
- Although absolute rules on flow communication between facies are not apparent, as the size of the reservoir compartment decreases, stratigraphic variability often increases and secondary compartments are often encountered in the smaller size reservoirs.
- The application of SGR approaches conducted with the cooperation of independent operators documented development costs in the range of $0.60 to $0.80/Mcf for incremental reserve appreciation.
- In the Boonsville Field, a previously unrecognized karst collapse phenomenon identified by 3-D seismics may be a widespread influence on the deposition of younger sediments in the Midcontinent.
- A reasonable approach to identifying new well locations in the Bend interval appears to be to focus 3-D seismic evaluation on multiple stacked completion opportunities. An alternative strategy would be to use 3-D data to identify fault-bounded blocks that have no penetrations in sub-regional or field-scale areas where the pre-Atoka time structure is low and total Atoka net reservoir isopachs are thick, increasing the potential for finding multiple vertically stacked completion opportunities.
- Fractures associated with faults and with maximum flexure on positive structural features control the locus of highest Ellenburger reservoir quality. Accordingly, the requirement for siting productive wells is to place the wellbore where it will penetrate the maximum amount of fractured rock. Seismic attributes that show significant stratal movement and distortion are valuable indicators of fracturing.

The most important measure of the SGR Project's success was the substantial increase in the assessed secondary natural gas resources and the increased production of gas in targeted districts of the Texas Gulf Coast. Knowledge of the technologies applied by the project was transferred to industry through a program of 14 short courses and workshops conducted by the SGR team and attended by more than 600 individuals, primarily independent producers and consultants. The incremental increase in national secondary gas production ascribable to the knowledge disseminated and the technologies developed

and applied by the SGR project was estimated to be 30 percent, when comparing industry performance during pre-SGR time (1990-1992) with performance in 1996.

Extrapolating from the 1993 drilling rate to 2000 and ascribing only 20 to 30 percent of the incremental production to the SGR project, gross incremental production revenue by 2000 would range from $916 million to $1,374 million, at prices of no more than $2.51 (1994 dollars) per Mcf, for the Gulf Coast alone. These revenues are as much as 60 times the entire SGR team investment. Moreover, based on the improved understanding of the relationship between among reservoir complexity, integrated technology assessments, and reserve growth potential, the 1996 GRI estimate of secondary gas resource grew to 508 Tcf for lower 48 onshore and state waters.

Table 3.6.1: List of Key Research Reports for Secondary Gas Recovery Program (1987-1995).

Report Number	Title	Authors	Organization	Date
DOE/MC/25031-5097	Secondary Gas Recovery: Targeted Applications for Infield Reserve Growth in Midcontinent Reservoirs – Boonsville Field, Fort Worth Basin, TX	Hardage, B.A., Carr, D.L., Finley, R.J., Tyler, N., Lancaster, D.E., Elphick, R.Y., Ballard, J.R.	Bureau of Economic Geology, at the University of Texas	July 1995
DOE/MC/25031-3834	Targeted Technology Applications for Infield Reserve Growth – A Synopsis of the Secondary Natural Gas Recovery Project Research, Gulf Coast Basin (Topical and Final Report)	Levey, R.A., Finley, R.A., Hardage, B.A.	Bureau of Economic Geology, at the University of Texas	June 1994
DOE/MC/25031-unp.	Integrated Strategies for Carbonate Reservoir Reserve Growth: An Example from the Ellenburger Group, Permian Basin, West Texas	Hardage, B.A., Major, R. P.	Bureau of Economic Geology, at the University of Texas	March 1998

4. Elements of Spreadsheet Bibliographies (by Program)

A bibliography of documents related to each of the resource programs outlined in the report is attached in the form of an Excel spreadsheet. This spreadsheet includes individual worksheets for each of the six resource programs, as well as a general listing of documents related to the entire unconventional gas resource (UGR) program (e.g., proceedings of meetings of UGR program contractor meetings, semi-annual reports of the entire UGR program, bibliographies, reports and analyses related to the entire UGR program, etc.).

Each of the resource program worksheets includes the following items for each entry:

Disc Number – This column indicates on which disc the specific scanned document is to be found. In the case of the Eastern Gas Shales and Western Gas Sands programs the large number of scanned documents required multiple CDs.

Document Number – This column indicates any number assigned to the specific document. DOE documents often are identified by a coded number (e.g., DOE/MC/14693-1296) as are documents printed by national labs (e.g., SNL 82-1638C). The NETL library in Morgantown maintains a series of vertical files identified by an Unconventional Gas Resource (UGR) number. These files may each contain a single document, map or log, or multiple items in some cases. All of these documents are related to the various UGR programs. Not all documents or reports have UGR numbers.

Title – Title of the document. In some cases these have been abbreviated slightly.

Author – Authors, last name of primary author first. In cases where there is no listed author, the authoring organization is listed.

Company or Publication – Organization responsible for the publication, or in the case of a technical paper, the sponsoring organization and meeting at which it was presented.

Date – Date of publication (year, month and day, when available).

Pages – Number of pages.

Notes – Indication of the type of special document (e.g., log, map) or if there are a number of oversized figures (plates) associated with the document.

Also included in the spreadsheet are separate worksheets that provide lists of publications related to unconventional gas research carried out over the same time period. These worksheets include:

- Well logs and well test packages related to wells drilled as part of the Eastern Gas Shales, Western Gas Sands, and Methane from Coal Seams R&D Programs, as well as basin reports related to the Methane from Coal Seams Program (including maps and logs). These have been scanned and are listed in the worksheet marked "Well Logs and Basin Reports." **These materials are available from the NETL library on request.**

- Society of Petroleum Engineers (SPE) papers (from the time period) on the topics of coalbed methane, naturally fractured gas shales (Devonian shales), and tight gas sands. A number of those listed are directly related to work done by the DOE in the various resource programs covered in this report and are copyright-free. **These copyright-free papers have been included as scanned documents on the accompanying CDs, under the appropriate resource category.**

- Gas Technology Institute (GTI, previously the Gas Research Institute or GRI) reports and other publications related to R&D on: naturally fractured gas shales, coalbed methane and tight gas sands. Many of these reports relate to work that was either partially funded by DOE or was an outgrowth of early research carried out by DOE under the UGR programs. **These reports are not included in this archive, the listing is for reference purposes only.** Many of these reports are available from GTI and can be ordered from their website at www.gastechnology.org.

- Selected published papers (from the time period) related to fractured shale reservoirs other than those which were the primary target of research under the Eastern Gas Shales program; specifically, the Bakken Shale of the Williston Basin of North Dakota and Montana, and the Barnett Shale of the Fort Worth Basin of Texas. **These papers are not included in this archive, the listing is for reference purposes only.**

Appendix A: Details of Major 1970-1980 Unconventional Gas Resource Assessments

Federal Power Commission (FPC) 1973 – "Natural Gas Survey – Supply Report"
Volume 2 of this 5-volume report is a 662-page volume that presents the work of the Technical Advisory Task Force on Gas Supply, so that the analytical data and findings could be made available to the public. Accomplishments of the task forces on natural gas supply, natural gas technology, regulation and legislation are presented. This document is available from the Government Printing Office for a nominal fee.

Energy Research and Development Administration (ERDA) (National Academy of Sciences) 1976 – "Natural Gas from Unconventional Geologic Sources"
This 255-page report focuses on the four major types of methane occurrences that had not been exploited to any significant degree: (1) the geopressurized zone of the Gulf Coast; (2) brown shales of the Appalachian and other Eastern U.S. basins of Devonian-Mississippian age; (3) tight sands of the Uinta, Piceance, and other western basins; and (4) coal seams. In a series of thirteen written papers presented in a forum sponsored by the Board on Mineral Resources and in discussions following the presentation of the papers, evaluations were made of the nature and physical dimensions of these reservoirs, the extent of the resource, recovery problems, economic and institutional problems, and the potential of the resource both in the short-term and the long-term. The papers and discussions are compiled, together with a summary of the findings and conclusions. This document is available from the NTIS for a nominal fee.

DOE (Federal Energy Regulatory Commission) June 1978 – "National Gas Survey: Non-Conventional Natural Gas Resources"
In this 116-page report, an analysis is presented of the future energy situation in the U.S. with emphasis on the natural gas industry. The analysis results are presented in chapters on historical research efforts, industry criteria for commercialization of coal bed gas, technology for recovering methane from coal beds, identification of problems, legal concerns, and environmental considerations.

DOE (Lewin & Associates) 1978 – "Enhanced Recovery of Unconventional Gas"
This report consists of three volumes:

Volume I – Executive Summary (60 pages, 14 figures) This volume is comprised of three parts discussing the public policy issues, proposed research strategy in enhanced gas recovery, and methodology.

Volume II – Proposed Research Program (578 pages).

Volume III – Methodology (407 pages) This volume is comprised of chapters on the analytic approach, estimated natural gas production, recovery from tight gas sands, recovery from Devonian shales, recovery from coal seams, and recovery from geopressured aquifers.

This study was conducted to assist public decision-makers in selecting among many choices to obtain new gas supplies by addressing two questions: 1) how severe is the need for additional future supplies of natural gas, and 2) what is the economic potential of providing part of future supply through enhanced recovery from unconventional natural gas resources? The study also served to assist the DOE in designing a cost-effective R&D program to stimulate industry to recover this unconventional gas and to produce it sooner. The DOE contract number was EF-77-C-01-2705. ***An electronic copy is included on the CD accompanying this document.***

National Petroleum Council 1980 – "Unconventional Gas Sources"
The report consists of five volumes: Volume I - Executive Summary (56 pages); Volume II - Coal Seams (128 pages); Volume III - Devonian Shale (252 pages); Volume IV - Geopressured Brines (212 pages); Volume V - Tight Gas Reservoirs (Part I - Resource Assessment is 492 pages, and Part II - Basin Analyses is 800 pages).

For each gas source, reserve additions and producing rates are calculated at five gas prices, three rates of return, and at least two levels of technology. The volumes also include an overview of the resource, an analysis of the technological state of the art, an examination of constraints or uncertainties that may impede development or production, and a comparison of the NPC findings with those of other studies on the resource.

The documents are available from www.npc.org for prices ranging from $2.50 to 440, depending on volume.