

**UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION**

Southwest Gas Storage Company

§

Docket No. RP07-____-000

**PREPARED DIRECT TESTIMONY
OF
EDWARD H. FEINSTEIN**

1 **Q. Please state your name and business address.**

2 A. My name is Edward H. Feinstein and my business address is 1155 15th Street,
3 N.W., Suite 400, Washington, D.C. 20005.

4 **Q. Please state your occupation.**

5 A. I am a consulting petroleum engineer with the firm of Brown, Williams,
6 Moorhead & Quinn, Inc.

7 **Q. Please briefly describe your education, background and training.**

8 A. I received my Bachelor of Petroleum Engineering degree at the University of
9 Tulsa in May 1963. From July 1963 to February 1998, I worked at the Federal
10 Energy Regulatory Commission ("FERC or Commission") and its predecessor,
11 the Federal Power Commission ("FPC"). From the time of my employment at
12 the FPC until approximately 1970, I was engaged in work involving economic
13 feasibility studies in certificate proceedings under the Natural Gas Act ("NGA").
14 This work was concerned primarily with market, engineering, and financial
15 analyses for the purpose of determining the economic feasibility of pipeline
16 projects proposed in certificate applications. From 1970 to the present, my
17 efforts have been concentrated on determining the appropriate depreciation rates

1 for oil and gas pipeline facilities, including the determination of potential
2 supplies of oil and natural gas, and with other rate issues such as storage
3 utilization, operations and cost allocation and gathering rates. During my nearly
4 35 years with the Commission, I earned positions of increasing responsibility,
5 including Chief of the Depreciation Branch. In March 1998, I joined the firm of
6 Brown, Williams, Scarbrough and Quinn, Inc., precursor to Brown, Williams,
7 Moorhead & Quinn, Inc. ("BWMQ"). At BWMQ, my efforts concerning various
8 depreciation and negative salvage issues have included oil and natural gas
9 pipelines and electric generating and transmission companies.

10 **Q. Are you a member of any professional societies?**

11 A. Yes, I am a member of the Society of Depreciation Professionals and the Society
12 of Petroleum Engineers.

13 **Q. Have you testified in proceedings before the FPC and the FERC?**

14 A. Yes, I have presented testimony in many different areas in the field of energy,
15 including depreciation and negative salvage. A list of testimony served in recent
16 proceedings is shown in Exhibit No. SGS-52.

17 **Q. What is the purpose of your testimony?**

18 A. The purpose of my testimony is to determine the just and reasonable depreciation
19 and negative salvage rates to be applied to Southwest Gas Storage Company's
20 ("Southwest Gas Storage") depreciable underground storage system. As part of
21 the support for my determinations, I am presenting an assessment of certain U.S.
22 gas supplies as they relate to the viability of Southwest Gas Storage's present day
23 properties.

1 **Q. Would you please summarize the results of your analysis of depreciation and**
2 **negative salvage for Southwest Gas Storage?**

3 A. Based on my study of the relevant facts (as discussed in further detail below), I
4 found Southwest Gas Storage's existing depreciation rate of 3.60 percent for its
5 Underground Storage Plant function to be presently a little too high. With
6 respect to its capital recovery depreciation rate, I found that its existing rate of
7 3.60 percent should be adjusted downward to 1.95 percent in order to recoup its
8 investment in such facilities over a reasonable regulatory recovery period.

9 Associated with depreciation are issues of negative salvage. With respect
10 to negative salvage, I found that Southwest Gas Storage should begin accruing
11 funds to cover the cost of storage field retirements. For the underground storage
12 plant, I recommend a negative salvage rate of 0.97 percent of the gross
13 depreciable plant.

14 A comparison of Southwest Gas Storage's existing authorized
15 depreciation rate, with the rates indicated by my analysis is shown on Schedule
16 No. 1 of Exhibit No. SGS-53.

17 **Q. Would you please summarize how you determined the indicated**
18 **depreciation and negative salvage rate?**

19 A. I analyzed Southwest Gas Storage's system operations along with all the forces
20 that affect the useful life. I determined an average remaining life of Southwest
21 Gas Storage's facilities based on their physical lives and an economic end life of
22 28 years. I also considered how competition and changing gas supply in the
23 natural gas industry affects the economic life of Southwest Gas Storage's

1 facilities. I applied the average remaining life to each of Southwest Gas
2 Storage's plant accounts to determine the composite depreciation rates for the
3 underground storage facilities. The methodology I employed for determining
4 Southwest Gas Storage's just and reasonable depreciation rates is consistent with
5 Commission precedent.

6 The negative salvage rate for the underground storage plant was
7 determined by applying the terminal net salvage estimate provided to me by
8 Southwest Gas Storage witness Mr. Taylor. The methodology employed is
9 consistent with that used in previous proceedings where the Commission
10 authorized negative salvage rates.

11 I. DEPRECIATION

12 **Q. Let us turn first to a definition of depreciation. Would you please define and**
13 **describe depreciation?**

14 A. Depreciation is the allocation of the original cost of tangible facilities in service
15 over their useful lives. Stated another way, depreciation is the mechanism by
16 which the plant investment is recouped in an orderly fashion over the useful life
17 of the investment. For rate purposes it is treated the same as an operating
18 expense. Depreciation is intended to systematically recover the invested capital
19 over the useful life of the universe of relevant assets.

20 The concept of depreciation can be viewed in the light that the purchase
21 of capital goods is in essence a purchase of future services. Consequently,
22 depreciation is the expiration or consumption, in whole or in part, of the service
23 life, capacity, or utility of property resulting from the action of one or more of the

1 forces operating to bring about the retirement of such property from service. It
2 therefore follows that the basic objective of depreciation under established
3 regulatory practice is the recovery of the full capital investment in facilities in a
4 reasonable and consistent manner over the time period related to such facilities'
5 use in providing service. This means that customers who are served by a
6 particular investment pay for that investment in timed installments over the life
7 of the investment.

8 Plant costs are incurred to make the provision of services possible. Units
9 of plant are no more than stored up services, or stored up work units. The use of
10 plant results in the provision of services and reduces the stored up future
11 services. As service is performed, a corresponding part of the cost of plant (cost
12 of stored up services) should be charged to the service. The stored up services
13 are usually referred to as the service life. Accordingly, depreciation signifies the
14 using up of service capacity or utility of plant.

15 **Q. What is the definition of depreciation in the Commission's Uniform System**
16 **of Accounts?**

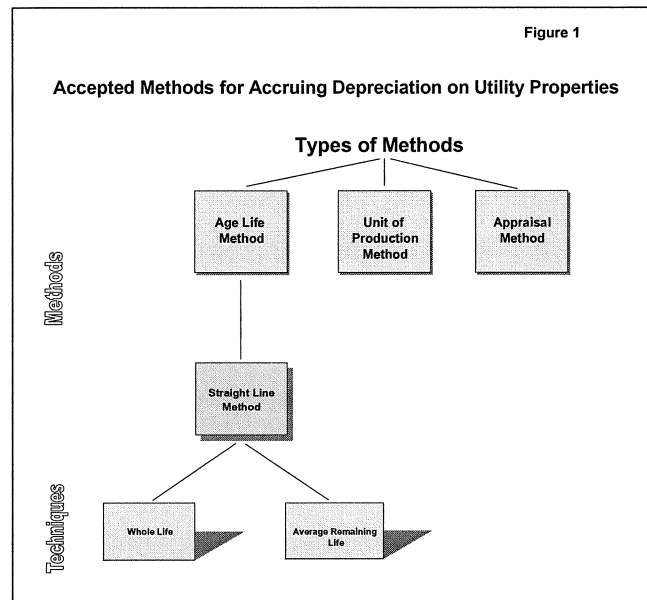
17 A. The Commission in its Uniform System of Accounts prescribed for natural gas
18 companies defines depreciation as follows:

19 "Depreciation" as applied to depreciable gas plant, means the loss
20 in service value not restored by current maintenance, incurred in
21 connection with the consumption or prospective retirement of gas
22 plant in the course of service from causes which are known to be
23 in current operation and against which the utility is not protected
24 by insurance. Among the causes to be given consideration are
25 wear and tear, decay, action of the elements, inadequacy,
26 obsolescence, changes in the art, changes in demand and

requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.

Q. What methodology did you use in your study to determine the appropriate life for Southwest Gas Storage's facilities?

A. I used the Average Service Life Methodology and recommend that Southwest Gas Storage's depreciation rate in this case be based on this methodology. This methodology is the most widely used of all the methods to determine depreciation rates for major onshore transmission pipeline systems. A diagram of depreciation methodologies is outlined below in Figure 1.



Depreciation rates depend on estimates of service life of plant investment. Because natural gas pipeline systems are made up of a host of different complex property units, it is impractical to calculate and apply separate depreciation rates for each unit of facility. This calculation would place an undue burden on the

1 accounting system, requiring the maintenance of records for each unit of
2 property. Consequently, the normal approach for developing depreciation rates
3 is to calculate the rates for groups of plant based upon average service lives for
4 those groups which are determined through studies of the forces affecting the
5 lives of the pipeline's facilities. Under this method, individual facilities booked
6 to each relevant FERC account are treated as a single group by those accounts.
7 Such approach is commonly referred to as the composite depreciation rate
8 method.

9 **II. DETERMINATION OF DEPRECIATION –**
10 **THE REMAINING LIFE FACTORS**

11 **Q. Would you please discuss the relationship between useful life and**
12 **depreciation?**

13 A. The measurement of depreciation recognizes that all plant will ultimately reach
14 the end of its useful life. The end of the useful life and retirement from service is
15 impacted by the following factors:

- 16 ▪ wear and tear
- 17 ▪ action of the elements
- 18 ▪ deterioration
- 19 ▪ inadequacy
- 20 ▪ obsolescence
- 21 ▪ requirements of public authorities and
- 22 ▪ adequacy of supply or market.

23 The physical causes, such as wear and tear and deterioration, are the most
24 readily observed reasons for retirements. Normal use of facilities involves
25 fatigue of materials, stress and friction, which results in wear and tear. An
26 example of wear and tear is the wearing out of major components of compressor

1 stations. Deterioration, on the other hand, may be caused by rusting, chemical
2 processes, or temperature variations. An example of deterioration is the
3 corrosion of metal pipeline segments that require costly repairs or retirement.

4 Functional causes, such as inadequacy, obsolescence, requirements of
5 public authorities and inadequacy of supplies or markets are probably the more
6 prevalent causes of retirements in the pipeline industry.

7 Inadequacy refers to the lack of capacity, which is required for supply and
8 demand. Thus, a storage line may be retired and replaced by one of larger size in
9 order to achieve an adequate delivery level.

10 Obsolescence may result in retirements due to improvements that render
11 certain facilities uneconomical and inefficient. A common example of
12 obsolescence is the communication equipment used by the pipeline industry.
13 New communication equipment is being developed continually.

14 Public authorities may from time to time require pipelines to be replaced
15 with thicker walled pipe because of population encroachment toward such
16 facilities, or relocated because of infrastructure improvements, such as highway
17 widening.

18 For a natural gas storage system such as Southwest Gas Storage, all of the
19 above causes of retirement, whether physical or functional, have one thing in
20 common: they are ever-occurring and affect individual facilities. On the other
21 hand, the adequacy of supply or market is unrelated to the physical
22 characteristics of the property or the action of public authorities. The adequacy
23 of supply and markets is probably the single most important factor resulting in

1 premature retirements because this factor may affect a large portion of a storage
2 system. Therefore, I will treat this subject in more detail.

3 In a depreciation study, the adequacy of supply and markets is referred to
4 as the economic life.

5 **III. THE DEPRECIATION MODEL**

6 **Q. Would you please describe the depreciation model that you employed in**
7 **your study?**

8 A. I employed the straight-line average remaining life method as traditionally
9 adopted by the Commission. In theory, the determination of the annual
10 depreciation expense is derived by division of the investment by the life estimate
11 as depicted in the following formula:

12
$$\text{Depreciation Expense} = \frac{\text{Investment}}{\text{Life}}$$

13 For the remaining life approach the annual depreciation expense is derived by
14 division of the undepreciated portion of the investment by the determined
15 average remaining life of such investment as depicted in the following formula :

16
$$\text{Depreciation Expense} = \frac{\text{Undepreciated Investment}}{\text{Average Remaining Life}}$$

17 The Depreciation Model shown below includes the specific components
18 necessary to derive the amount of the undepreciated investment includable in the
19 depreciation expense computation:

$$DE = \frac{DB - (S - COR) - DR}{ARL}$$

Where,

DE = the annual depreciation expense
DB = the depreciation base or original cost
S = the gross salvage
COR = the cost of removal
DR = the accumulated depreciation reserve
ARL = the average remaining life

The determination of the depreciation rate simply reflects the division of the annual depreciation expense divided by the depreciation base or the original cost of the facility being depreciated as depicted in the formula below:

$$\text{Depreciation Rate} = \frac{DE}{DB}$$

The determination of depreciation using the above equations serves three purposes:

capital recovery - ratably allocates a known fixed cost,

cost of removal - ratably allocates a future obligation, and

salvage - ratably reflects recognition of future value.

Q. Would you describe the average remaining life approach?

A. The concept of an average remaining life approach or remaining service life for a property group recognizes that the various units in the group have differing lives. The average life of any group of plant items is a matter of estimate until all the items in that group have been finally retired. The issue then is to determine the average life before complete retirement of all units occurs. The average

1 remaining service life method determines the average period of time the facilities
2 will be in service. This is normally done by first determining the average life of
3 the plant group and then estimating the life expectancy for the items remaining in
4 service. The life of individual units plus the expected life the entire property
5 class comprises the average life for the group. This approach is referred to as the
6 life span principle. A life span group contains units, referred to as mass property
7 that will concurrently retire in a specific number of years after placement. For
8 life span groups (mass property), there may be interim additions and retirements.
9 All plant, however, will be subject to a final retirement. This analysis can be
10 done by determining the separate lives for each of the property units or by
11 constructing a survivor curve for the entire mass property group. In this
12 testimony, I employed the group method and I used a survivor curve for each
13 mass property group of facilities.

14 **Q. What is a survivor curve?**

15 A. A survivor curve, fitted to a particular type of plant, assists in the prediction of
16 the average remaining service life and retirement pattern of that type of plant. A
17 survivor curve graphically reflects the percent of capital investment existing at
18 each age throughout the entire physical life of an original group of property.
19 From the survivor curve, the average service life or average remaining life can be
20 calculated. The average service life is obtained by calculating the area under the
21 survivor curve from age zero to the maximum age and dividing the area by 100
22 percent. The average remaining life at any age is obtained by calculating the area

1 under the survivor curve from the observation age to the maximum age, and
2 dividing this area by the percent of plant surviving at the observation age.

3 The average remaining life is the average length of time that all units of a
4 group are expected to last. The retirement pattern estimates how much of the
5 group will be retired each year as the group ages. The average remaining life,
6 which is of particular importance in the calculation of the depreciation rate, is
7 derived from the useful life of the facility and from each plant's survivor curve.

8 Analyses of historical data are employed in estimating average service
9 lives due strictly to physical or commonly occurring retirement forces. The
10 analyses consist of compiling the past history of the plant groups, reducing the
11 history to mortality trends by the use of actuarial techniques, and forecasting the
12 trend of survivors for each depreciable group on the basis of past trends and
13 future company plans. The combination of the historical trend and the future
14 trend yields a complete survival pattern from which the physical portion of the
15 average service life is derived. The historical experience data upon which
16 indications of past service life are based reflect not only the capital investment of
17 property items retired during each year of age but also the capital investment of
18 property items that remain in service at the beginning of each year of age out of
19 the total capital investment originally placed in service in any year. These
20 properties that remain in service are said to be exposed to the risk of retirement.

21 The survivor curves are referred to as Iowa type survivor curves as
22 depicted on Schedule No. 3 of Exhibit No. SGS-53.

1 The survivor curves were originally developed at the Iowa State College
2 Engineering Experiment Station and refined through an extensive process of
3 observation and classification of the ages at which industrial property had been
4 retired. Iowa survivor curves are used to account for the normal retirements that
5 occur over the life of a specific type of plant.

6 The determination and use of a survivor curve to determine the physical
7 life of facilities requires experience and knowledge in the interpretation of the
8 results of such a study. The use of judgment must include investigation into
9 whether future normal retirements can be predicted based on the past
10 performance of those facilities. It is important to note that, while the
11 determination of a survivor curve based upon historical plant additions and
12 retirement data is a valuable tool in the evaluation of the average service life,
13 other factors that relate to the useful life must also be considered, such as the
14 operation of the facilities in the future.

15 **Q. Please explain how you applied this information.**

16 A. In order to put the average service life, economic life and resulting average
17 remaining life in proper perspective, I employed the group method of
18 determining depreciation. Rather than determining the life of each and every
19 facility, the group method treats large amounts of Southwest Gas Storage's
20 facilities as a group in the useful life determination. The facilities are grouped by
21 FERC account. This is the normal, Commission-approved methodology. Further,
22 it is important to note that the economic life determined relates to Southwest Gas
23 Storage's existing facilities.

IV. DETERMINATION OF THE AVERAGE SERVICE LIFE

Q. Would you please discuss the determination of the average service life of the facilities that make up Southwest Gas Storage's underground storage system?

A. A summary of the average service lives (physical life) along with the type survivor curve is shown in Schedule No. 10 of Exhibit No. SGS-53 and discussed below.

There are eleven broad groups of facilities that make up the underground storage system. They correspond to specific account numbers:

- Account 350.1, Rights of Way
- Account 351.10, Well Structures
- Account 351.20, Compressor Station Structures
- Account 351.30, Measuring and Regulating Sta. Structures
- Account 351.40, Other Structures
- Account 352, Wells
- Account 353, Lines
- Account 354, Compressor Station Equipment
- Account 355, Measuring and Regulating Sta. Structures
- Account 356, Purification Equipment
- Account 357, Other Plant

V. UNDERGROUND STORAGE PLANT

Account No. 350.2 – Rights of Way

The company's investment in Rights of Way is \$336,405. The rights of way are located in the states of Kansas, Oklahoma, Illinois and Michigan. This account includes the cost of all interests in land which do not terminate in the short term. Typical average service lives of underground storage rights of way is 40 to 65 years. Some underground storage systems function for less than 20

1 years. For Southwest Gas Storage's rights of way, I used an average service life
2 of 51 years.

3 Assets in this account would have average service lives somewhat longer
4 than the wells and storage lines, due to the fact that not all well and pipeline
5 retirements will result in the retirement of the related rights-of-way. Facility
6 retirements, whether replaced or not will be within the same rights-of-way.

7 **Account No. 351.1 – Well Structures**

8 The company's investment in this account is \$73,537. This account
9 contains the housing, fences and other structures associated with the
10 injection/withdrawal wells. Based on my analysis of the above type facilities as
11 well as the industry-wide service life of such facilities, a service life of 34 years
12 was employed.

13 **Account No. 351.2 – Compressor Station Structures**

14 Structures in this account include those of compressor stations. The
15 company's investment in this account is \$8,189,294. The facilities are comprised
16 of foundations, roadways, superstructures, fences and fire protection equipment.
17 Typical lives of the compressor station structures is 25 to 35 years. I employed
18 34 years as the average service life. Analysis of the type of equipment in this
19 account, as well as the experience of other underground storage systems which
20 operate similar facilities, results in a 34-year average service life.

21 **Account No. 351.3 – Measuring and Regulating Equipment Structures**

22 The investment in this account is \$620,962. Structures in this account
23 include those related to gas control, such as meters and related measuring

1 facilities. Such facilities are regulation building, fences and roadways. Typical
2 lives for these structures is also 25 to 35 years. I employed 34 years as the
3 average service life.

4 **Account No. 351.4– Other Structures**

5 The investment in this account is \$2,664,382. Structures in this account
6 include miscellaneous facilities associated with the storage operation. Typical
7 lives for these structures is also 25 to 35 years. I employed 34 years as the
8 average service life.

9 **Account No. 352 – Wells**

10 The company's investment in this account is \$40,488,601. This account
11 is made up of the storage injection/withdrawal and observation wells. This
12 account includes the drilling cost of all wells. This account is comprised of
13 various cost items such as: drilling contractors, charges, casing, water and mud
14 used in the drilling process, equipment fences, fittings such as valves and casing
15 heads, tanks and tubing. Typical lives for the equipment in this account is 10 to
16 50 years. I employed an industry wide average of 41 years. My analysis
17 indicates that a 41-year life is reasonable to develop depreciation for the facilities
18 in this account.

19 **Account No. 353 – Lines**

20 The current investment in storage field pipelines is \$27,658,832. The
21 facilities are comprised of pipeline mains, valves, cathodic protection, line pack
22 and drips. Typical lives for pipeline mains in an underground storage field is 30

1 to 55 years. I employed an average service life of 39 years to Southwest Gas
2 Storage's storage lines.

3 **Account No. 354 – Compressor Station Equipment**

4 The company's investment in compressor station equipment is
5 \$37,009,473. The facilities in this account is comprised of the main
6 reciprocating compressor units, station piping, valves, odorizing unit, gas heating
7 boiler, emission control devices and an assortment of other related equipment.
8 Typical lives for compressor station equipment in storage fields ranges between
9 20 and 45 years. I employed an average service life of 33 years for the facilities
10 in this account.

11 **Account No. 355 – Measuring and Regulating Station Equipment**

12 The company's investment in this account is \$4,052,995. It is made up of
13 typical gas volume and pressure measuring equipment, such as orifice runs,
14 electronic meters, chromatograph and associated equipment such as valves,
15 associated pipe and headers.

16 Analysis of the type of equipment in this account, which are standard in
17 the pipeline industry, as well as the experience of other companies, both
18 underground storage and pipeline, result in a 30-year average service life. The
19 range of average service lives of such equipment is 15 to 40 years.

20 **Account No. 356 – Purification Equipment**

21 The company's investment in this account is \$1,723,926. It is made up of
22 condensers, dehydrators, their foundations and settings, pumps, heaters, inlet
23 valve piping, scrubbers, impurity removal apparatus and associated water

1 disposal equipment. Typical lives of the above equipment range between 20 and
2 35 years. I employed a 26-year average service life for such equipment.

3 **Account No. 357 – Other Equipment**

4 The company's investment in this account is \$688,457. It is made up of
5 equipment used in connection with the underground storage operation, which is
6 not assignable to any of the other accounts. Typical items are calorimeters,
7 control installations and odorizing units.

8 Analysis of the type of equipment in this account as well as the
9 experience of other companies, which operate similar facilities results in a 28-
10 year average service life. Typical average service lives vary between 15 and 35
11 years.

12 **Q. Mr. Feinstein, when there is no historical retirement and salvage data, is the**
13 **use of industry wide values of average service life and negative salvage study**
14 **reliable?**

15 **A.** I believe that the average service life ("ASL") and negative salvage amounts
16 allowed and used by other underground storage operators are highly reliable for
17 two reasons. First, the facility make up of most underground storage fields are
18 similar to Southwest Gas Storage. Second, my experience based on studies and
19 analysis of the lives and removal cost of underground storage equipment indicate
20 that the values exhibited by Southwest Gas Storage's peers are very similar. For
21 example, see Schedule No. 11 of Exhibit No. SGS-53. It shows the industry-
22 wide average service lives which I have adopted.

1 While cognizant of the operations of Southwest Gas Storage's facilities
2 and my experience with the average service lives of similar facilities operated by
3 other companies, I adopted average service lives based on the AGA Survey of
4 underground storage operators and various company's estimated average service
5 lives. I believe this approach establishes a reasonable regulatory recovery period
6 for a storage asset. The determinations are shown on Pages 2 through 8 of
7 Schedule No. 11 of my Exhibit No. SGS-53.

8 **Q. Would you please describe your analysis of Southwest Gas Storage's system**
9 **as it relates to the useful life of its facilities?**

10 A. The purpose of the depreciation study is to determine the useful life of Southwest
11 Gas Storage's underground storage facilities. To achieve this goal, I analyzed
12 and determined the forces bringing about retirement of Southwest Gas Storage's
13 facilities. Those forces, as mentioned earlier, are the physical such as wear and
14 tear, etc and an adequate supply of natural gas, a market to serve and competition
15 for both supply and markets.

16 **VI. ECONOMIC LIFE OF SOUTHWEST'S**
17 **UNDERGROUND STORAGE PROPERTIES**

18 **Q. Would you please describe Southwest Gas Storage's underground storage**
19 **system?**

20 A. Southwest Gas Storage owns and operates underground natural gas storage
21 facilities in the Borchers North Storage Field, Meade County, Kansas; the North
22 Hopeton Storage Field, Woods County, Oklahoma; the Waverly Storage Field,
23 Morgan and Sangamon Counties, Illinois; and the Howell Storage Field,

1 Livingston and Washtenaw Counties, Michigan. All of these fields are
2 connected to the Panhandle Eastern Pipe Line Company, LP ("Panhandle")
3 interstate pipeline system. Southwest Gas Storage provides both firm and
4 interruptible storage service in its east area (midwest) and west area (southwest).
5 See the map on Schedule No. 2 of Exhibit No. SGS-53.

6 Borchers North Storage Field is a dry gas volumetric reservoir with a
7 base gas volume of 35.1 Bcf. It has 5 compressors totaling 15,000 hp. The
8 maximum developed working storage capacity is 28.3 Bcf. The field is operated
9 with 45 injection/withdrawal wells.

10 North Hopeton Storage Field is a water drive reservoir with a base gas
11 volume of 11.6 Bcf and a maximum working capacity of 10.0 Bcf. The field
12 operates with 3 compressors totaling 5,600 hp. Currently, Southwest Gas
13 Storage proposed to increase the base gas to 14.6 Bcf and reduce the maximum
14 working storage capacity to 3.5 Bcf in order to reflect actual field performance.
15 Nine wells were drilled as injection/withdrawal wells and five original producing
16 wells were reworked for injection/withdrawal operation.

17 Waverly Storage Field is an aquifer reservoir complex comprising three
18 different reservoirs. The formations that make up the three reservoirs were
19 originally water-filled. Gas was injected to makeup a "bubble" and form an
20 operating storage field. The field has a base gas volume of 46.6 Bcf. The
21 horsepower compression is 5,550 hp. The maximum developed working storage
22 capacity is 5 Bcf. This field operates with 37 injection/withdrawal wells and 17
23 withdrawal-only wells.

1 The Howell Storage Field is a dry gas volumetric reservoir with a base
2 gas volume of 13.4 Bcf. The maximum developed working storage capacity is
3 17.8 Bcf. There are 67 wells, both observation and injection/withdrawal in the
4 field. The field operates with 4 compressors totaling 6,000 hp.

5 **Q. Would you please describe your analysis of the economic life of Southwest**
6 **Gas Storage's underground storage system as it relates to the useful life of**
7 **its facilities?**

8 A. The purpose of the depreciation study is to determine the useful life to establish a
9 reasonable regulatory recovery period for Southwest Gas Storage's underground
10 storage facilities. To achieve this goal, I analyzed and determined the forces
11 bringing about retirement of Southwest Gas Storage's facilities. One of those
12 forces, as mentioned earlier, is an adequate supply of natural gas.

13 **Q. How did you determine the adequate supply of gas that relate to Southwest**
14 **Gas Storage's storage fields?**

15 A. I am presenting an assessment of the amount of gas available in the
16 Midcontinent, Gulf Coast and northern Rocky Mountain area. These studies
17 determine the availability of natural gas over the period 2006 through 2035 (See
18 Exhibit No. SGS-54, *Assessment of the Availability of Natural Gas in the*
19 *Northern Rocky Mountain Area the Midcontinent area and the Gulf Coast Area.*

20 **Q. What economic life did you use in your depreciation determination?**

21 A. I used an average economic life of 28 years as a composite for all four of
22 Southwest Gas Storage's storage fields. This is based on an economic life of 25
23 years for Southwest Gas Storage's Midcontinent storage fields (Borchers and

1 North Hopeton) and an average economic life of 30 years for the Midwest
2 storage fields (Waverly and Howell).

3 **Q. How did you arrive at 25 years as the economic life for the existing facilities**
4 **of Southwest Gas Storage's Borchers and North Hopeton storage fields?**

5 A. In the development of a 25-year economic life, I considered various factors such
6 as supply, demand and competition. The selection of 25 years as the economic
7 life or economic horizon is based on a decline in throughput to 50 percent of
8 pipeline utilization, which are supplied with gas from the Midcontinent and
9 northern Rocky Mountain areas. Pipeline utilization directly affects the optimum
10 use of a storage facility. Less than optimum capacity in a storage field affects the
11 deliverability, which in turn leads to the redundancy of facilities. This is shown
12 on Schedule No. 9 page 1 of Exhibit No. SGS-53.

13 **Q. How did you arrive at 30 years as the economic life of the Midwest storage**
14 **fields – Waverly and Howell?**

15 A. The selection of 30 years as the economic life or economic horizon for the
16 Waverly and Howell storage fields is also based on the decline in throughput to
17 50 percent of pipeline utilization. The point at which a 50 percent utilization of
18 pipelines, whose source of supply is the Gulf Coast, is 30 years. This is shown in
19 Schedule No. 9, page 2 of Exhibit No. SGS-53. To the extent that the Waverly
20 and Howell storage fields are sourced with Midcontinent and Rocky Mountain
21 gas supplies as well as the Gulf Coast actually add an additional element of
22 uncertainty as the 50 percent utilization point is reached in less than 30 years.

1 **Q. What is the significance of the 50 percent utilization point of pipelines**
2 **related to Southwest Gas Storage's underground storage systems?**

3 A. Due to the complex nature of the operations and cost of underground storage
4 systems that when only 50 percent of gas (as compared to 100 percent) is
5 available, a tipping point may be reached as to the economic viability of a
6 particular storage field. For storage to operate optimally, a certain level of
7 capacity must be maintained. I believe that very few underground storage fields
8 can operate at a level of 50 percent, or even levels somewhat higher. When
9 underground storage fields operate at levels significantly less than they are
10 designed (capacity, deliverability and pressure) to operate they will not conform
11 to contractual volume levels and thus become uneconomic.

12 **Q. How did you determine the average economic life of Southwest Gas**
13 **Storage's entire storage system?**

14 A. The overall average economic life of Southwest Gas Storage's underground
15 storage system is the product of weighting the economic lives selected for the
16 Borchers North and the North Hopeton storage fields with the Waverly and
17 Howell storage fields employing the relative investment value of the two. The
18 investment value ratio is approximately 40 percent for Borchers North and North
19 Hopeton versus 60 percent for Waverly and Howell. When the ratios are applied
20 to the economic lives, the result is a 28 year weighted average economic life.

**VII. DETERMINATION OF DEPRECIATION FOR THE
SOUTHWEST GAS STORAGE UNDERGROUND STORAGE SYSTEM**

The Straight Line Remaining Life Approach

Q. Mr. Feinstein, would you please explain the difference between average service life, economic life and average remaining life?

A. First of all, the term “average” as used herein refers to the large amounts of property units that make up pipeline and storage systems.

The average service life is the useful life of groups of units from its in-service date to the date it is taken out of service or when it no longer performs a useful service. It is used in this application as the physical life.

The “economic life”, or, in this application, the “remaining economic life” of a group of units is the period of time from the current to the point where economic, rather than physical forces, bring about the end of its useful life.

The average remaining life is the useful remaining life when both economic and physical forces are considered together. The average remaining life is the direct marker to the calculation of the annual depreciation accrual. That is, in the remaining life technique of the straight line method, depreciation expense equals the quotient of the undepreciated plant and the average remaining life.

Q. How did you apply the economic life limits to the depreciation model?

A. The 25-year and 30-year remaining economic life limit plays a key role in the determination of the average remaining life. It represents the average year of the final recoupment of Southwest Gas Storage’s investment in its facilities as an

1 overall group. The best way to describe the relationship of the economic life to
2 the average remaining life is to overlay it with the normal retirement survivor
3 curve. The reason for overlaying the economic life to the survivor curve is that
4 normal or interim retirements will take place before the economic end life.

5 **Q. Please explain this procedure?**

6 A. When the economic life is applied to the survivor pattern, future normal
7 retirements beyond the average economic life are not relevant. The average
8 remaining life is determined by integrating or calculating the area under the
9 truncated survivor curve. For example, the compressor station equipment
10 associated with the flows of gas into (injection) and out (withdrawal) of the
11 storage wells, where the average service life (installation to retirement) is 33-
12 years, the average remaining life was determined to be 13.6 years. This is shown
13 in conceptional form in Schedule No. 12 of Exhibit No. SGS-53. Similar
14 determinations were made for the rest of the accounts in the underground storage
15 plant function (see Schedule No. 13 of Exhibit No. SGS-53).

16 **Q. Would you please explain the mechanics of your calculation of the**
17 **depreciation rate for the underground storage system?**

18 A. After determining the individual average remaining lives for each account, which
19 are shown in Schedule No. 13 of Exhibit No. SGS-53, I then divided each
20 average remaining life into the difference between the depreciable plant and the
21 accumulated reserve for depreciation, thus arriving at the indicated depreciation
22 expense. The indicated depreciation expense for each account was totaled. This
23 then is the indicated depreciation expense for the total underground storage plant.

1 The results of my calculation of the indicated composite depreciation rate for the
2 underground storage system, as well as the rate for each function, is shown on
3 Schedule No. 15 of Exhibit No. SGS-53. The indicated rate for the total
4 underground storage system is 1.95 percent.

5 In order to reflect near-term plant additions and retirements for purposes
6 of rate stability, I performed the calculation of depreciation for a period of three
7 years beginning in 2007 and ending in 2009. This is also shown on Schedule No.
8 15 of Exhibit No. SGS-53. I then calculated the indicated depreciation rate by
9 dividing the total indicated 3-year expense by the relevant depreciable plant.

10 The procedure for determining the depreciation rate is illustrated in the
11 diagram shown in Schedule No. 14 of Exhibit No. SGS-53.

12 **VIII. NEGATIVE SALVAGE**

13 **Q. Mr. Feinstein, would you now please turn to the issue of negative**
14 **salvage. Please explain the term “negative salvage.”**

15 A. Negative salvage is the net amount of funds necessary to retire a specific facility
16 or group of facilities. It is the difference between the gross salvage, if any, and
17 the cost of removal. Gross salvage may be in the form of value of the facilities
18 stored in a warehouse for reuse or the proceeds from a sale of such facilities.

19 **Q. What is a negative salvage rate?**

20 A. A negative salvage rate is the annual rate, as a percent of the gross plant
21 (traditional Commission approach), subject to retirement that will accrue enough
22 funds in an orderly and fair manner to cover the cost of retirement. I used the

1 same straight line remaining life method that I employed to determine the
2 depreciation rates to accrue negative salvage funds.

3 The negative salvage rate reflects the future obligation of removal when
4 the plant is retired. Like depreciation, the cost of retiring facilities is a legitimate
5 cost of doing business. It is both reasonable and necessary for the ratepayers
6 who are receiving service from these facilities to fund the additional costs of
7 retirements through negative salvage depreciation rates. To ensure that an
8 adequate reserve will be on hand to decommission the facilities when they are
9 retired, and to restore the land to its original condition, I recommend that
10 Southwest Gas Storage propose to collect such an amount in rates over the
11 estimated remaining useful life of its plant. Failing to include such an expense in
12 current rates will force a subsequent generation of ratepayers to subsidize service
13 provided to current ratepayers. Furthermore, a negative salvage allowance
14 requires current ratepayers to pay the cost of using these facilities by bearing
15 their fair share of these costs.

16 **Q. What determines the manner in which abandonment takes place?**

17 A. Authorization under Section 7(b) of the Natural Gas Act for the abandonment of
18 natural gas facilities provides for actions that require an environmental
19 assessment by the FERC (see 18 C.F.R. § 380.5 (2001)). Further, other
20 regulating entities have requirements governing the removal of a company's
21 facilities. It is this process which establishes abandonment authorization. As
22 with any regulated entity, Southwest Gas Storage has the burden to
23 decommission its facilities correctly and restore the land to its original condition.

1 For example, each of the states in which Southwest Gas Storage operates its
2 storage fields, require specialized treatment for the abandonment of
3 injection/withdrawal and observation wells. Such abandonment procedures are
4 costly.

5 **Q. In your view, will Southwest Gas Storage's facilities eventually be**
6 **decommissioned?**

7 A. Southwest Gas Storage's pipeline facilities will have to be decommissioned.
8 Surface, as well as buried pipeline facilities, wells, compressor equipment,
9 metering equipment, structures and processing facilities eventually wear out,
10 become obsolete or uneconomic. This fact is demonstrated by my plant
11 retirement and survivor curve analysis, which reflects retirements due to physical
12 causes. Gas supply, markets and facility utilization studies reflect retirements
13 that occur due to the same storage facilities becoming obsolete, redundant or
14 otherwise unnecessary. At some point, each natural gas facility reaches the end
15 of its useful life.

16 **Q. What did you calculate Southwest Gas Storage's negative salvage rate for**
17 **underground storage facilities to be and how did you determine that rate?**

18 A. A terminal negative salvage ("TNS") study encompassing Southwest Gas
19 Storage's four underground storage facilities was prepared by Southwest Gas
20 Storage witness, Mr. James S. Taylor.

21 In addition to Mr. Taylor's study, I determined the cost of removal of interim
22 retirements that will take place during the service life of the storage systems.
23 The difference between the two studies is that Mr. Taylor's TNS study

1 determines the decommissioning cost (in current dollars) of Southwest Gas
2 Storage's entire storage system, considering today's facilities in service; while
3 my study of the cost of removal of interim retirements reflects the cost of retiring
4 plant that will not be in service at the TNS point in time.

5 Based on my analysis of interim retirements, and their related cost of
6 removal, along with a TNS study performed by Mr. Taylor, I determined a
7 composite underground storage plant net negative salvage rate to be 0.97 percent.

8 **Q. Can you provide a more detailed description of your determination?**

9 A. My determination of the appropriate negative salvage rate for the storage
10 facilities began by my analysis of Southwest Gas Storage's existing facilities,
11 along with the decommissioning process of such facilities and familiarizing
12 myself with Mr. Taylor's terminal salvage and cost of removal study. The
13 summary of the TNS estimate is shown on Schedule No. 16 of Exhibit No. SGS-
14 53.

15 My determination of the negative salvage rate is a combination of two
16 distinct annual negative salvage accrual calculations – interim negative salvage
17 and terminal negative salvage. The negative salvage rate is the quotient of the
18 estimated annual negative salvage accruals, divided by the gross plant. I
19 determined the negative salvage base for the ongoing normal, interim retirements
20 separately from the final closure (TNS), because each has an associated average
21 life different from the other.

22 **Q. How did you employ Mr. Taylor's TNS estimate in your negative salvage**
23 **rate determination?**

1 A. I adjusted the TNS estimate to account for the amount of current plant no longer
2 in service 28 years hence due to interim retirements. Normal retirements will
3 occur from 2006 for a period of an average of 28 years reflecting the average
4 economic life. That is, of today's plant approximately 45 percent will be replaced
5 due to their normal physical life in 28 years. The remaining facilities will be
6 subject to the final closure at the 28-year average remaining economic life. This
7 reduces the magnitude of Mr. Taylor's estimate. This calculation is shown on
8 Schedule No. 19 of Exhibit No. SGS-53.

9 The adjusted TNS estimate is then combined with the negative salvage of
10 the interim retirements to arrive at the recommended overall negative salvage
11 rate for Southwest Gas Storage's storage plant. The procedure of combining the
12 two negative salvage increments are shown in Schedule No. 20 of Exhibit No.
13 SGS-53. The average remaining economic life was applied to the final closure
14 estimate. I then created a composite of the 28-year accrual period for the final
15 closure with the 13.25-year accrual period for the interim retirements to arrive at
16 an average period of 20.6 years. This is shown on Schedule No. 20 of Exhibit
17 No. SGS-53.

18 The 20.6-year period of time is the result of direct weighting of the net
19 negative salvage cost and the number of years to retirement.

20 **Q. Can you describe the mathematical calculations used to determine the**
21 **negative salvage rate?**

22 A. Schedule No. 21 of Exhibit No. SGS-53 shows the calculation of the negative
23 salvage rate for Southwest Gas Storage's underground storage plant. I divided

1 the estimated amount of negative salvage by the 20.6-year accrual period. I then
2 divided that quotient by the storage plant in service to arrive at 0.97 percent.

3 **Q. Would you please describe the determination of the negative salvage**
4 **increment of the interim retirements?**

5 A. I determined the retirements for each plant account from the same survivor
6 curves that I developed earlier for depreciation purposes. Recall that the survivor
7 curve is actually a graphic representation of normal retirements over a period of
8 time. The 28-year period of interim retirements for each relevant account in the
9 storage plant is shown on Schedule No. 17 of Exhibit No. SGS-53. I combined
10 all the interim retirements and determined a weighted average remaining life of
11 13.25 years that would apply as the average period of time to accrue the negative
12 salvage for the interim retirements. This is also shown on Schedule No. 17 of
13 Exhibit No. SGS-53.

14 After I determined the future annual normal or interim retirements for
15 each account that would be affected by negative salvage, I then applied various
16 net negative salvage values ranging from 10 to 23 percent as factors to the
17 anticipated facility retirements. These factors are supported by observation of
18 the historical retirement process and Mr. Taylor's analysis and determination and
19 of the experience of other gas companies operating underground storage systems.

20 **Q. Mr. Feinstein, would you please describe the process of retiring a typical**
21 **pipeline facility on an ongoing basis, that is an interim retirement?**

22 A. My determination of the negative salvage for interim retirements is based on the
23 sequence of events that take place during the retirement process. Interim

1 retirements will take place during the useful life of Southwest Gas Storage's
2 storage system. During that time frame, I have assumed that the retirements will
3 be replaced. The cost of a retirement that will be replaced is less than one that is
4 not replaced because of certain costs that are shared. This contrasts with Mr.
5 Taylor's analysis where there are no replacements.

6 A simplified example of the sequence of events that could possibly take
7 place during a storage field pipeline replacement is as follows:

8 **Planning and Mobilization**

- 9
 - Engineering workup
 - Mobilization to site

11
12 **Clean and Purge**

- 13
 - Isolate line segment
 - Blow down
 - Evacuation

16
17 **Remove Pipe from trench**

- 18
 - Trench excavation
 - Cutting pipe into sections

20
21 The above process might involve the following type of equipment and labor:

22 **Equipment**

- 23
 - Dozers (at least a D-6 Cat)
 - Backhoes (Cat 325B)
 - Flatbed trucks
 - Half ton pickup trucks
 - Assortment of tools

28
29 **Labor**

- 30
 - operators
 - teamsters
 - laborers
 - foreman
- 31
32
33

1
2 Remove pipe from trench, cut, load on trucks and haul to storage yard. The
3 following is necessary:

4 Equipment

- 5 • 30 ton Grove Hydrocrane
- 6 • Pipelayer (572-R Cat with 20 foot boom)
- 7 • Pipe trucks
- 8 • Low boy
- 9 • ¾ ton pickup truck with trailer
- 10 • ½ ton pickup
- 11 • Various tools

12
13 Labor

- 14 • Hydrocrane operator
- 15 • Operators
- 16 • Teamsters
- 17 • Pipefitters/welders
- 18 • Helpers
- 19 • Laborers
- 20 • Foreman

21
22 Other

- 23 • Environmental contractor
- 24 • Storage company inspection
- 25 • ROW damages
- 26 • Storage company management and overhead

27
28 **Pipe Handling and Storage**

29 This covers the unloading of pipe from trucks, store pipe in temporary
30 storage yard, loading pipe onto carriers for transport to scrap yard and loading
31 pipe in storage yard onto contractor's carriers. The following is necessary:

32 Equipment

- 33 • Grove 30 ton hydrocrane
- 34 • ½ ton pickups
- 35 • Various tools

36
37 Labor

- 38 • Operators
- 39 • Foreman

- Operator (hydrocrane)

1
2
3 **Q. Please describe your determination of the negative salvage cost for the**
4 **storage field pipeline interim retirements.**

5 A. In estimating the cost of removal for storage field pipeline interim retirements, I
6 applied 50 percent of the estimated cost to remove storage field lines, 75 percent
7 of the estimated costs to clean and purge and 100 percent of the pipe handling
8 and storage costs. I then subtracted that sum by the amount of positive salvage.
9 Positive salvage, as pipe is sold for scrap is *de minimus* when compared to the
10 total cost of removal per retirement unit. A contingency of 10 percent was then
11 added. The total cost of removal less gross salvage, as a percent of each interim
12 retirement unit is 12.8 percent, 42.9 percent, 20.3 percent and 16 percent for
13 Waverly, Howell, Borchers North and North Hopeton, respectively. The
14 composite negative salvage rate for interim retirements of storage field pipelines
15 is 23 percent. These calculations are shown on Schedule No. 18 of Exhibit No.
16 SGS-53.

17 **Q. Mr. Feinstein, how does the 23 percent negative salvage rate compare with**
18 **an industry average?**

19 A. The negative salvage rate that I derived for storage field lines of 23 percent
20 compares with the industry average of 28 percent, with a range of values of 5
21 percent to 100 percent.

22 **Q. Mr. Feinstein, is it possible that for each interim retirement unit there will**
23 **be no cost of removal or negative salvage?**

1 A. No. It is not possible. The cost of labor and equipment, necessary to retire today
2 and for the foreseeable future, will be significantly higher than any possible gross
3 salvage. This is supported by Mr. Taylor's study, as well as my investigation
4 into the procedure and actual cost of retirement.

5 I adjusted the terminal negative salvage estimate to reflect the fact that
6 some of the facilities will not be retired at final closure, but as normal (interim)
7 retirements over a previous period of time. Thus, the overall negative salvage
8 estimate related to current plant in service is based on two elements: the terminal
9 negative salvage estimate from current plant remaining in service at the time of
10 decommissioning and the negative salvage estimate for the interim retirements.
11 The computation of how Mr. Taylor's TNS is adjusted is shown on Schedule No.
12 18 of Exhibit No. SGS-53.

13 **Q. How do you recommend net salvage be reflected for accounting purposes for**
14 **Southwest Gas Storage's transmission plant?**

15 A. I recommend, consistent with past Commission practice, that Southwest Gas
16 Storage establish a sub-account for negative salvage in Account 108,
17 Accumulated Provision for Depreciation of Gas Utility Plant. Negative salvage
18 accruals and net salvage (gross salvage and cost of removal) will be recorded in
19 this sub-account. This treatment will enable the negative salvage accruals and
20 the actual net salvage costs resulting from retirements to be identified separately,
21 apart from the accumulated depreciation accruals.

22 **Q. What is the reason for creating this sub-account?**

1 A. There are two reasons for it. First, a sub-account allows the negative salvage
2 reserve to be reviewed periodically with ease. This allows the detection of
3 deficiencies or excesses in the accumulated reserve for negative salvage.
4 Second, when negative salvage accruals and net salvage costs from retirements
5 are reflected in the capital recovery depreciation reserve, such reserve is distorted
6 by the negative salvage amounts. Inflation, environmental and political
7 considerations may result in future negative salvage costs that may differ from
8 today's estimates.

9 **Q. Is the value of recoverable base gas considered salvage?**

10 A. No. It is not. Recoverable base gas is not a depreciable item. The net salvage
11 value only applies to depreciable plant. This is shown in the formula for
12 depreciation (see Page 10 of this Exhibit No. SGS-51). What distinguishes base
13 gas from plant subject to salvage and cost of removal is that under original cost
14 ratemaking, the investment in depreciable plant is allowed to be recovered over
15 its life through rates via depreciation while base gas is not depreciable.
16 Ratepayers pay a carrying charge on the un-recovered investment as well as an
17 increment to recoup the investment. Here, the investment to be recouped is the
18 original cost less any related salvage. On the other hand, recoverable base gas is
19 not depreciable. A pipeline company, while receiving a carrying charge does not
20 recoup its investment in recoverable base gas from rate payers. Recoverable base
21 gas and system balancing gas is purchased by the pipeline company, injected into
22 storage by the pipeline company and operated by the pipeline company. The cost
23 of such gas at the time it is abandoned is the sole responsibility of the pipeline

1 company. The cost disposition would take place at the time of abandonment.
2 The inclusion of any differences in value of recoverable base gas as an offset to
3 the allowed recoupment of depreciable asset is erroneous.

4 **Q. Has the Commission ever applied the value of recoverable base gas or the**
5 **gain on the sale of recoverable base gas to the determination of negative**
6 **salvage or depreciation?**

7 A. No.

8 **IX. SUMMARY AND CONCLUSION**

9 **Q. Would you please summarize your testimony?**

10 A. The purpose of my testimony is to determine the proper and adequate rate of
11 depreciation and accruals for negative salvage to establish a reasonable
12 regulatory recovery period for Southwest Gas Storage. To do so, I have analyzed
13 the tangible properties and operations of its underground storage system and
14 estimated its average remaining life. I determined an average remaining
15 economic life of 28 years. Based on this analysis, I developed a depreciation rate
16 of 1.95 percent and a negative salvage rate of 0.97 percent.

17 **Q. Does this conclude your prepared direct testimony?**

18 A. Yes, it does.

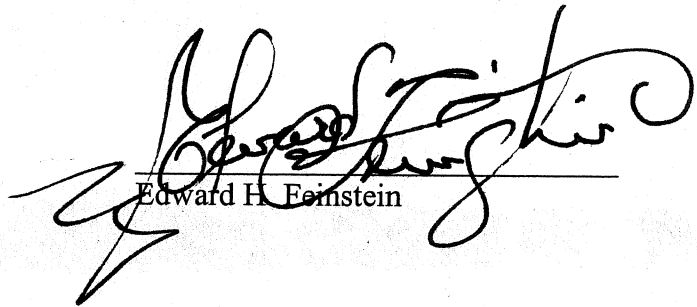
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southwest Gas Storage Company)

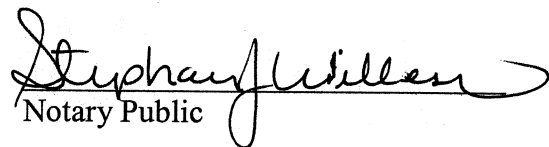
Docket No. RP07- -000

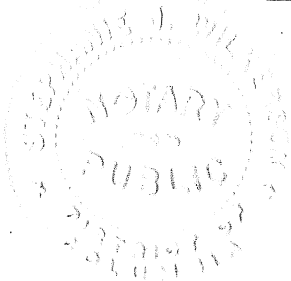
AFFIDAVIT OF
EDWARD H. FEINSTEIN

Edward H. Feinstein, being first duly sworn, deposes and says that he is the Edward H. Feinstein whose "Prepared Direct Testimony of Edward H. Feinstein" appears on the proceeding pages; that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth herein are true and correct to the best of his knowledge, information, and belief; and that he does adopt the same testimony in this proceeding.


Edward H. Feinstein

Subscribed and sworn before me, a Notary Public, in and for the District of Columbia, this 23rd day of July, 2007


Notary Public



My Commission expires: June 14, 2009

EXPERT WITNESS LIST
OF
EDWARD H. FEINSTEIN

Line No.	Docket No.	Company Name
1	RP76-91	Columbia Gulf Transmission Company
2	RP77-56	Northern Natural Gas Company
3	RP78-94	Texas Gas Transmission Corporation
4	RP79-80	Trailblazer Pipe Line Company
5	RP80-17	Trans-Anadarko Pipe Line System
6	RP81-17 & RP81-57	Midwestern Gas Transmission Company
7	RP81-54	Tennessee Gas Pipe Line Company
8	RP81-69	South Georgia Natural Gas Company
9	RP81-81	United Gas Pipe Line Company
10	RP81-109-000	Texas Eastern Transmission Corporation
11	RP82-58	Panhandle Eastern Pipe Line Company
12	RP83-93-000	Trunkline Gas Company
13	RP84-94-000	Stingray Pipeline Company
14	RP85-122-000	Colorado Interstate Gas Company
15	RP87-15	Trunkline Gas Company
16	RP89-49	National Fuel Gas Supply Corporation
17	RP89-55	Sea Robin Pipeline Company
18	RP89-72	Algonquin Gas Transmission Company
19	RP89-121	United Gas Pipe Line Company
20	RP90-69	Colorado Interstate Gas Company
21	RP91-68-000	Penn-York Energy Corporation
22	RP91-161-000	Columbia Gas Transmission Corporation
23	RP93-36-000	Natural Gas Pipeline Co. of America
24	RP93-187	Equitrans, Inc.
25	RP94-96-000	CNG Transmission Corporation
26	RP95-112-000	Tennessee Gas Pipe Line Company
27	RP95-185-000	Northern Natural Gas Company
28	RP95-197-000	Transcontinental Gas Pipe Line Corp.
29	RP95-409-000	Northwest Pipeline Corporation
30	RP95-408-000	Columbia Gas Transmission Corporation
31	RP95-306	Paiute Pipeline Company
32	RP96-129-000	Trunkline Gas Company
33	RP97-346-000	Equitrans, Inc.
34	RP98-290-000	Viking Gas Transmission Company
35	RP98-203-000	Northern Natural Gas Company
36	RP99-111-000	Koch Gateway Pipeline Company
37	RP99-485-000	Kansas Pipeline Company
38	RP99-322-000	Northern Border Pipeline Company
39	RP97-408-000	Trailblazer Pipe Line Company
40	RP99-381-000	Wyoming Interstate Company, Ltd.
41	RP99-471-000	Williams Field Services Group, Inc. v. El Paso Natural Gas Company
42	RP00-107-000	Williston Basin Interstate Pipeline Company
43	RP01-292-000	Mississippi River Transmission Company
44	RP02-132-000	Viking Gas Transmission Company
45	RP02-013	Portland Natural Gas Transmission
46	02-024-U	Arkansas Oklahoma Gas Corporation (APSC)
47	02-227-U	Arkansas Western Gas Company (APSC)
48	RP03-398-000	Northern Natural Gas Company
49	RP04-12-000	Florida Gas Transmission Company
50	RP03-625-000	Chandeleur Pipe Line Company
51	ER03-563-000	Devon Power LLC, et al.
52	RP04-97-000	Equitrans, Inc.
53	RP04-203-000	Equitrans, Inc.
54	ER03-753-000	Entergy Services, Inc.
55	RP04-274-000	Kern River Gas Transmission Company
56	EL00-105-007	City of Vernon
57	PUE-2004-00012	Virginia Natural Gas, Inc.
58	RP04-360-000	Maritimes & Northeast Pipelines, LLC
59	ER05-231-000	PSEG Connecticut Power, LLC
60	RP05-164-000	Equitrans, Inc.
61	RP04-155-000	Northern Natural Gas Company
62	RP05-163-000	Paiute Pipeline Company
63	RP06-369-000	El Paso Natural Gas Company
64	RP06-72-000	Northern Border Pipeline Company
65	RP06-336-000	Pine Needle LNG, LLC
66	ER06-____-000	Orion Power Midwest, LP
67	05-006-U	Arkansas Oklahoma Gas Corporation
68	RP06-416-000	Northwest Pipeline Corp.
69	RP06-407-000	Gas Transmission Northwest Corp
70	RP06-569-000	Transcontinental Gas Pipe Line Corp.
71	RP06-417-000	Dominion Cove Point LNG
72	RP07-310-000	Mojave Pipeline Company
73	RP07-34-000	Southwest Gas Storage Company

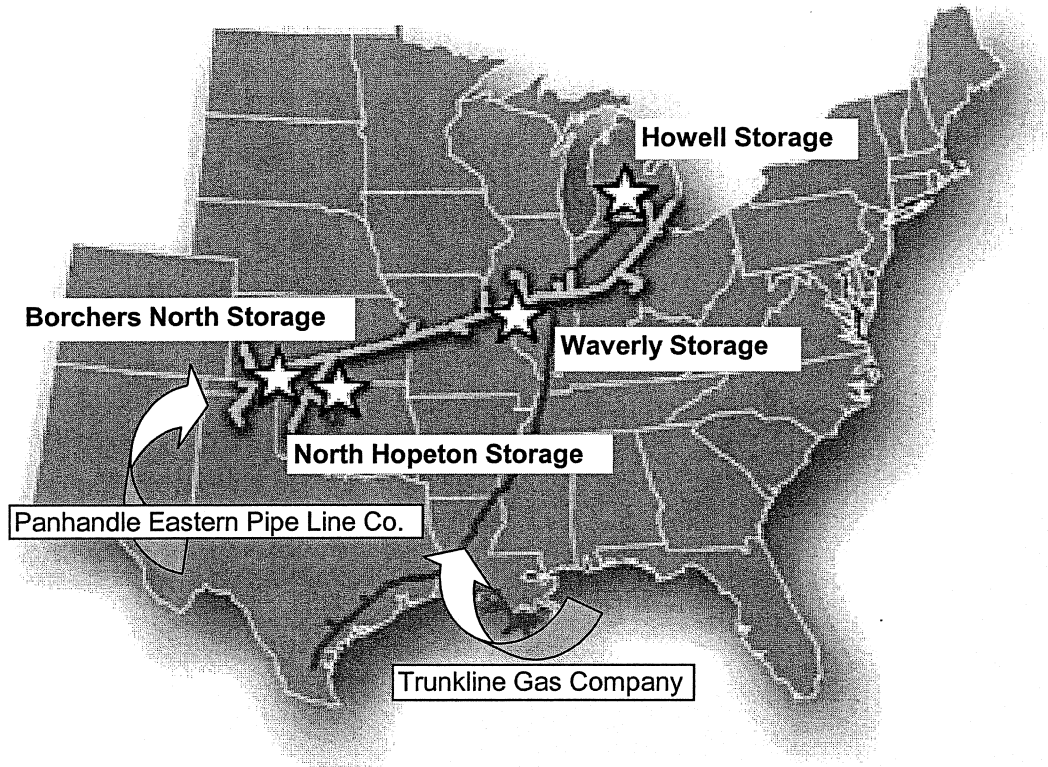
SOUTHWEST GAS STORAGE COMPANY

COMPARISON OF EXISTING DEPRECIATION RATES WITH INDICATED RATES

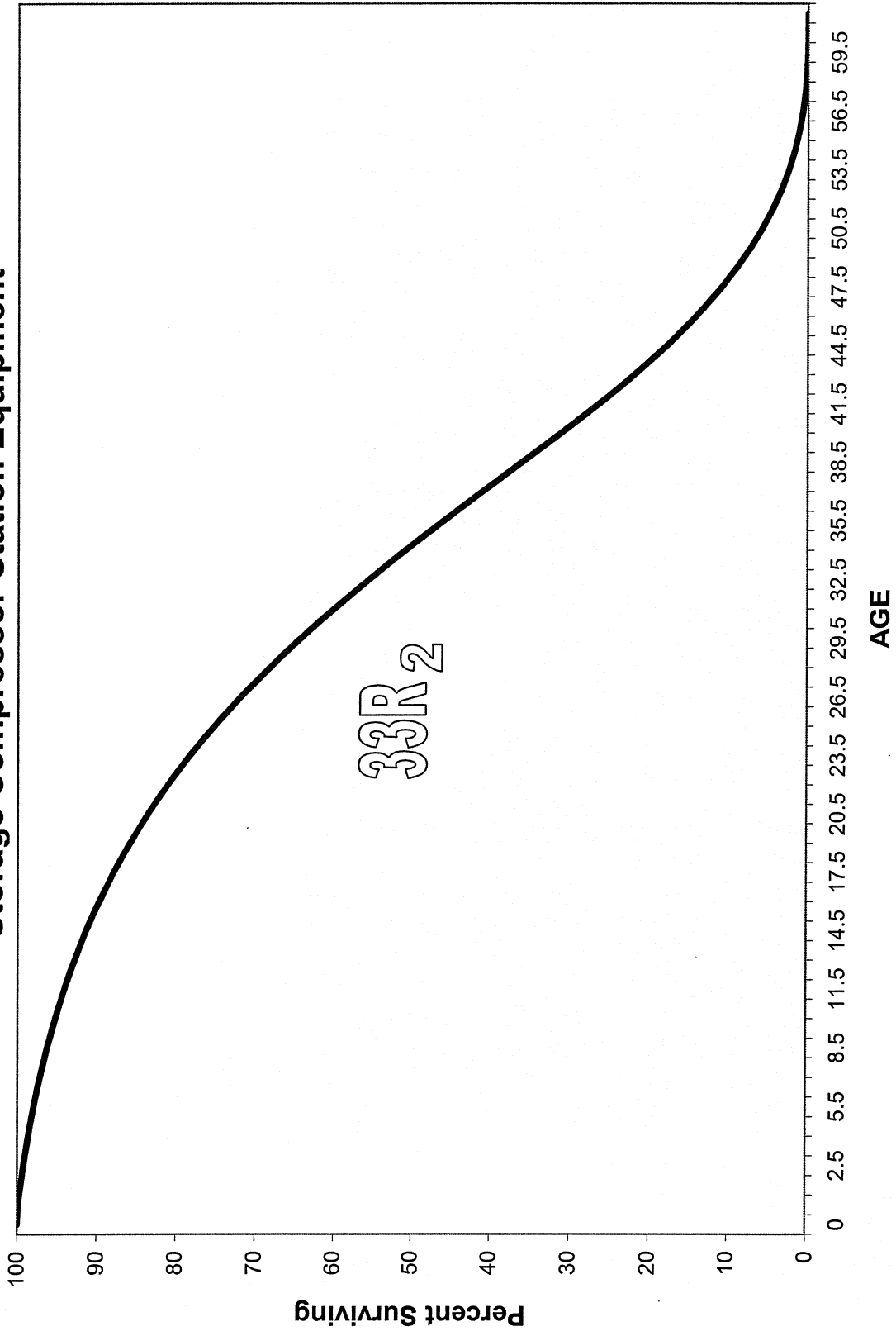
Gross Depreciable Plant	Existing Rates		Indicated Rates	
	Depreciation Capital Recovery	Depreciation Negative Salvage	Depreciation Capital Recovery	Depreciation Negative Salvage
\$				
181,859,631	3.6	0	1.95%	0.97%

Underground Storage

Southwest Gas Storage Company



Survivor Curve Storage Compressor Station Equipment

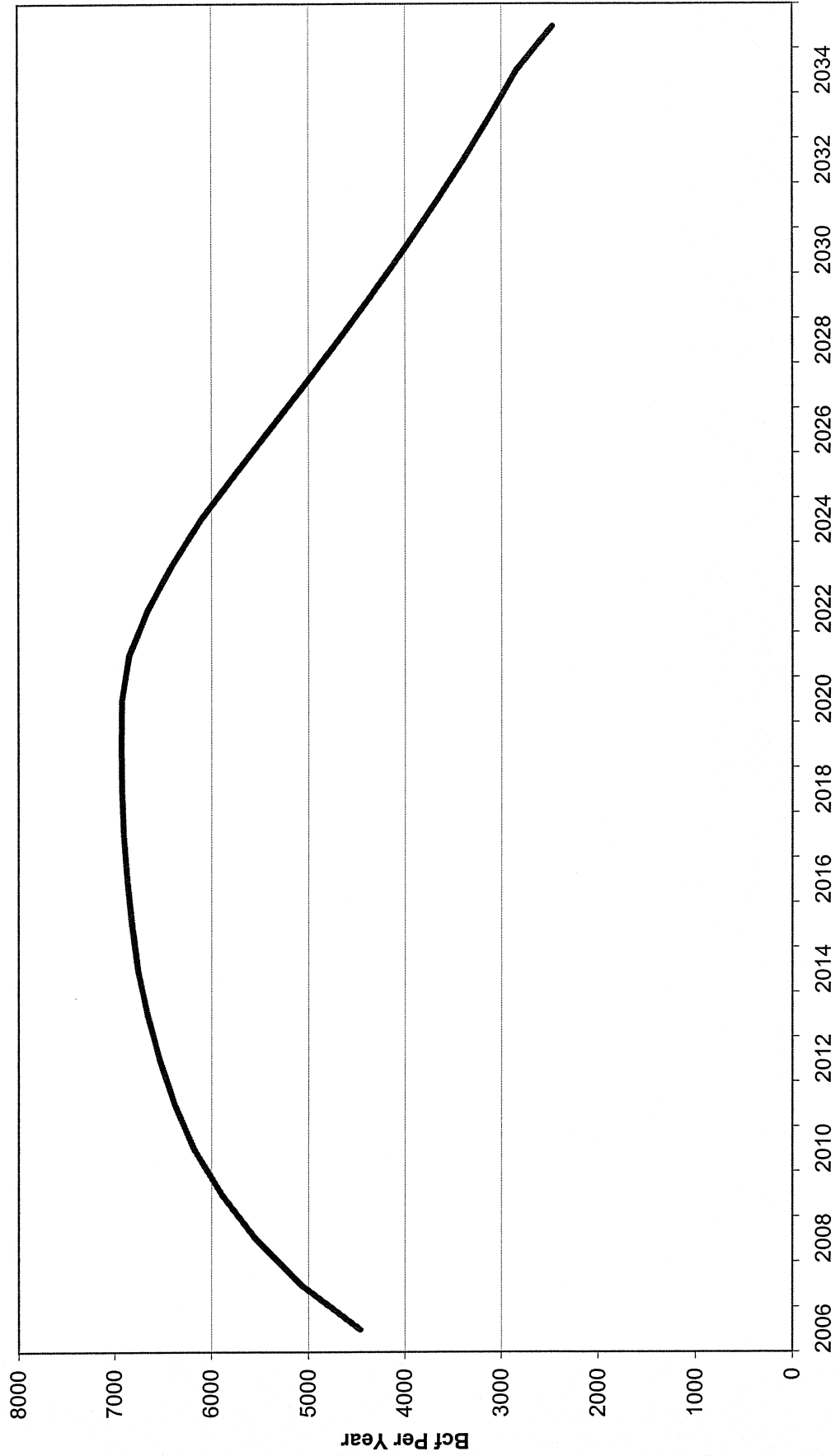


GULF COAST GAS SUPPLY PRODUCTIVE CAPACITY

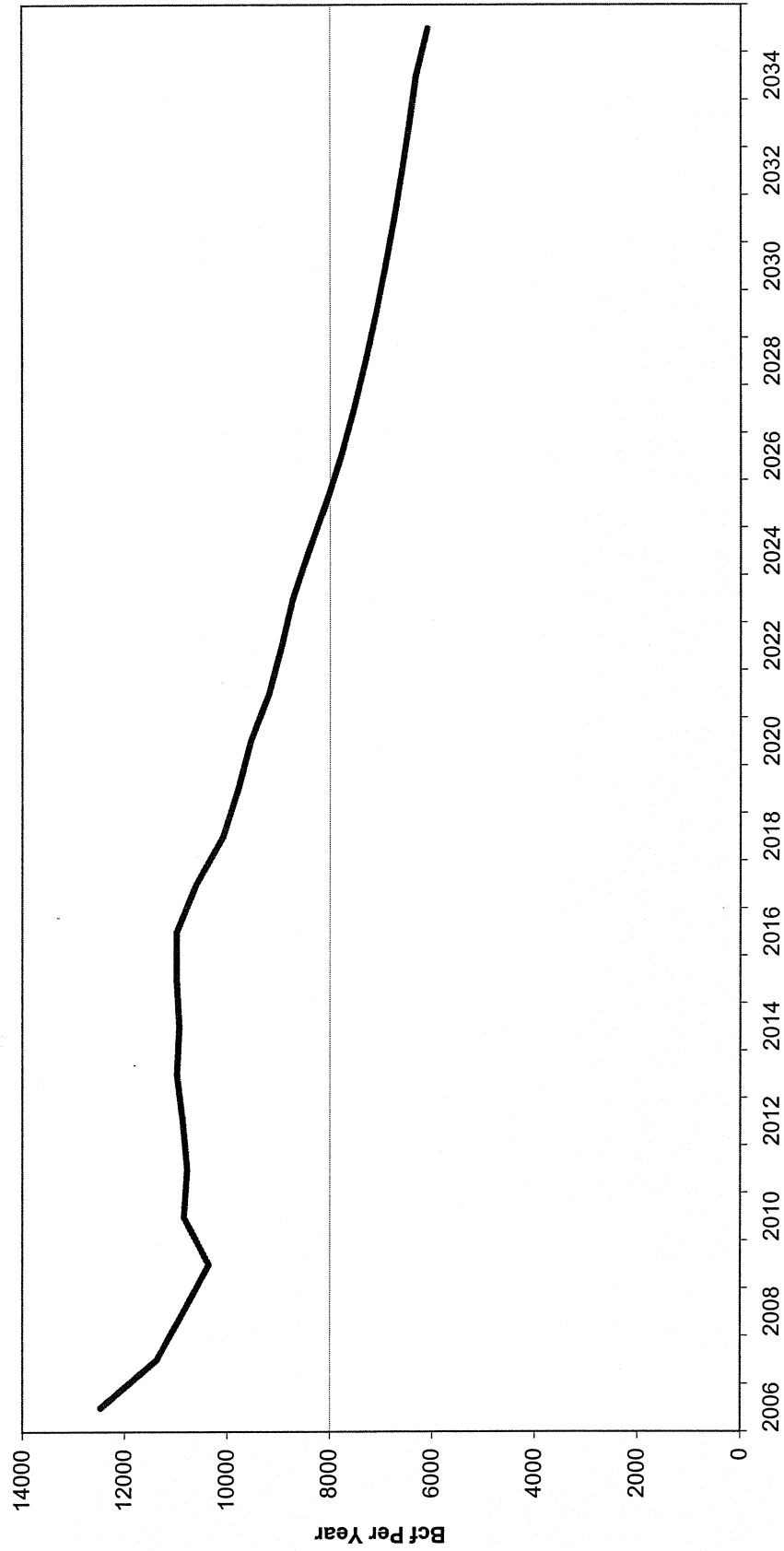
Bcf Per Year

Year	Onshore Louisiana	Onshore Texas Gulf Coast	Gulf of Mexico	Total 3 Areas	Estimated LNG Gulf Coast	Total Gulf Coast With LNG
2006	2,239	3,753	5,530	11,521	946	12,468
2007	2,089	3,927	4,277	10,293	1,082	11,375
2008	1,999	3,760	3,638	9,397	1,455	10,853
2009	1,981	3,621	3,263	8,865	1,487	10,353
2010	1,939	3,602	3,295	8,836	2,003	10,839
2011	1,889	3,535	3,223	8,646	2,129	10,776
2012	1,825	3,429	3,278	8,532	2,329	10,861
2013	1,779	3,224	3,294	8,297	2,678	10,975
2014	1,711	3,035	3,341	8,087	2,844	10,931
2015	1,624	2,815	3,354	7,793	3,185	10,978
2016	1,547	2,585	3,303	7,436	3,545	10,981
2017	1,460	2,379	3,198	7,037	3,569	10,606
2018	1,367	2,177	3,038	6,582	3,494	10,076
2019	1,274	1,984	2,854	6,112	3,666	9,778
2020	1,181	1,802	2,660	5,644	3,895	9,539
2021	1,089	1,633	2,466	5,188	3,991	9,179
2022	999	1,474	2,276	4,750	4,185	8,934
2023	910	1,327	2,094	4,331	4,385	8,716
2024	834	1,189	1,922	3,945	4,461	8,406
2025	761	1,074	1,754	3,589	4,484	8,073
2026	694	966	1,600	3,260	4,520	7,780
2027	632	868	1,458	2,958	4,574	7,532
2028	576	780	1,326	2,681	4,623	7,305
2029	524	700	1,204	2,428	4,668	7,097
2030	477	629	1,092	2,198	4,710	6,908
2031	435	564	990	1,989	4,748	6,737
2032	395	507	897	1,799	4,784	6,583
2033	359	455	812	1,626	4,817	6,443
2034	326	408	734	1,469	4,848	6,317
2035	283	367	601	1,250	4,840	6,090

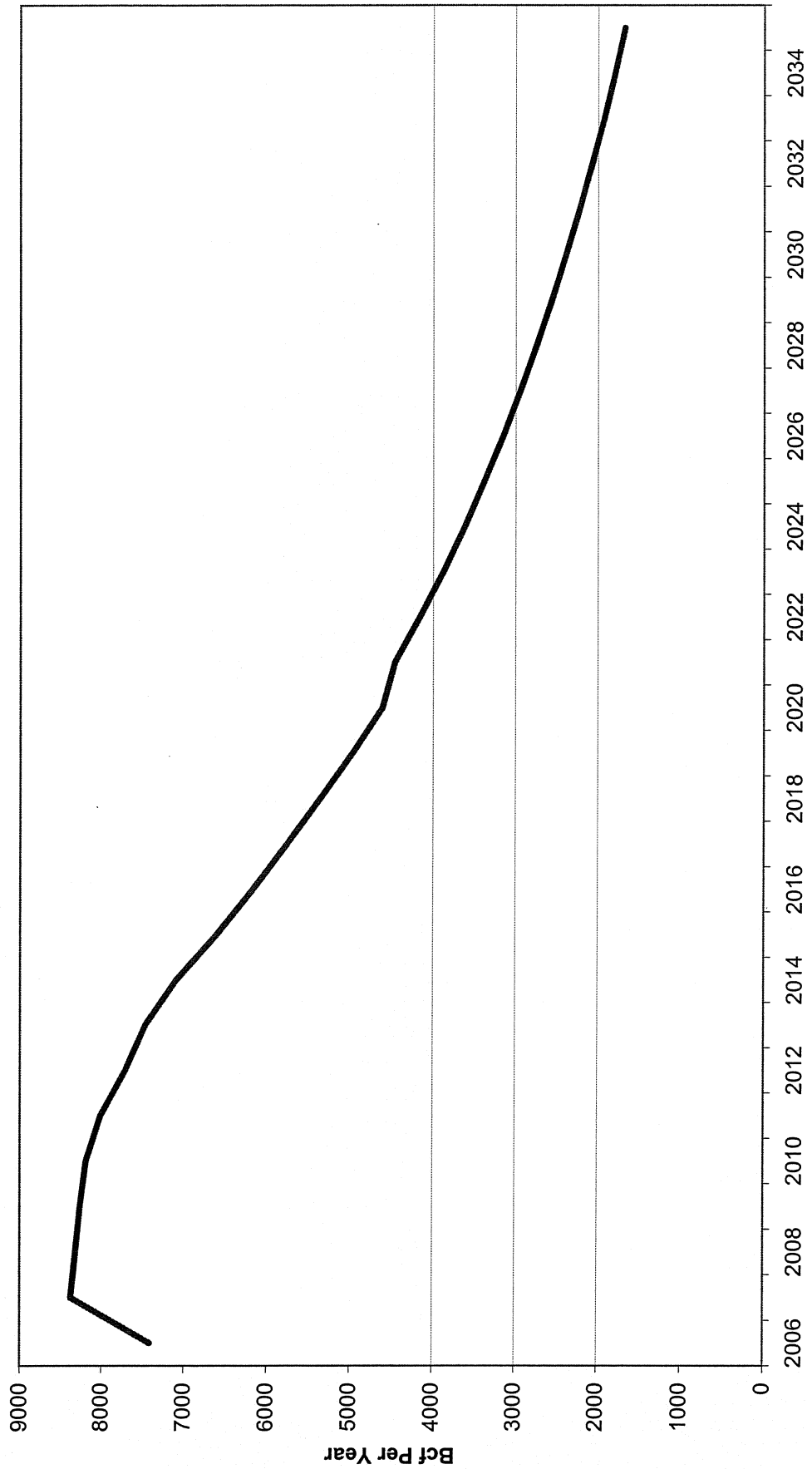
The Availability of Natural Gas in the Northern Rocky Mountain Area



The Availability of Natural Gas in the Gulf Coast Area



The Availability of Natural Gas in the Midcontinent Area

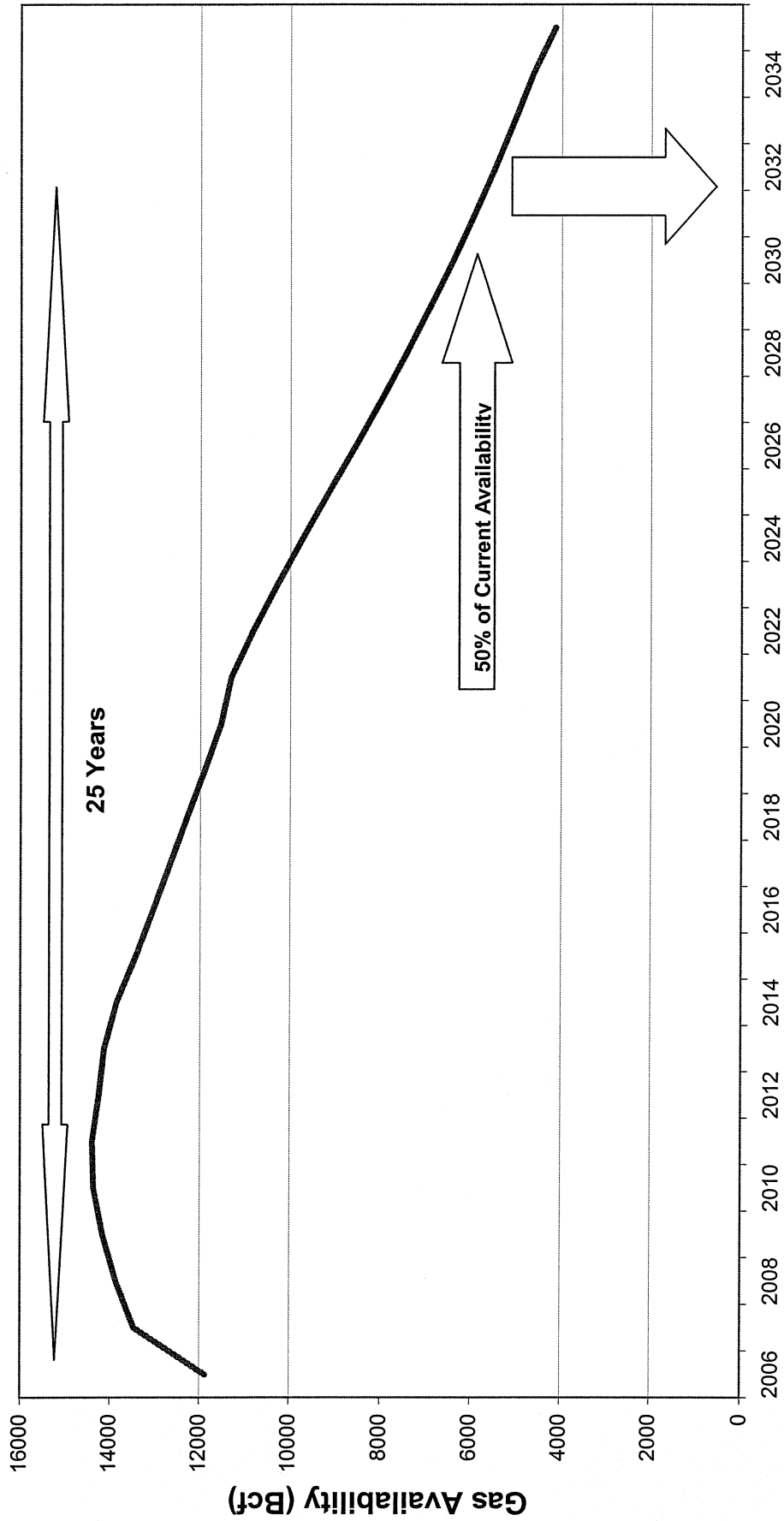


SOUTHWEST GAS STORAGE COMPANY

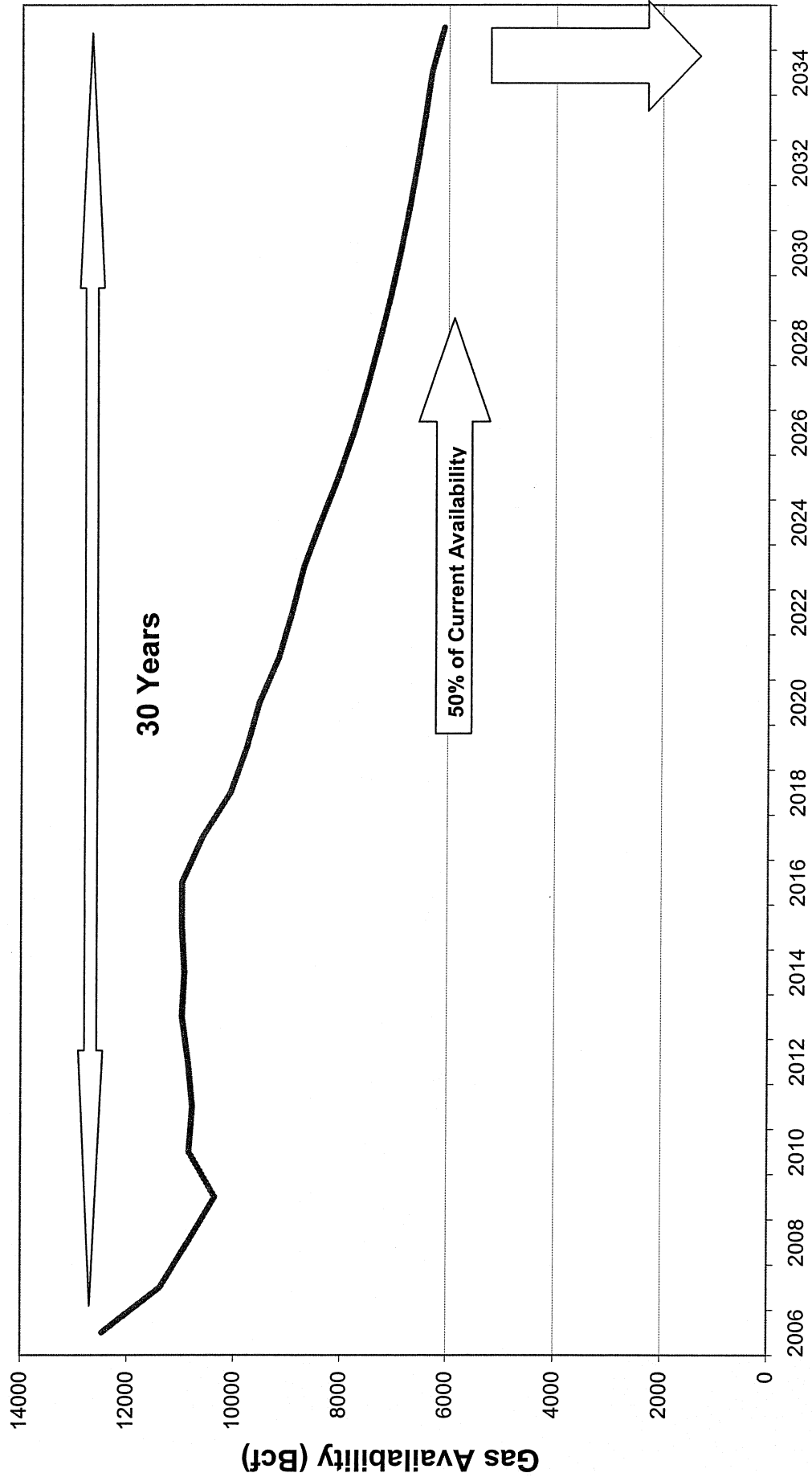
Total Natural Gas Productive Capacity Available to the Storage System

	Productive Capacity Bcf Per Year				Total
	Rocky Mountain Area	Midcontinent Area	Gulf Coast Region		
2006	4,461	7,408	11,869	12,468	24,337
2007	5,076	8,374	13,451	11,375	24,825
2008	5,537	8,317	13,854	10,853	24,706
2009	5,891	8,264	14,155	10,353	24,508
2010	6,172	8,190	14,362	10,839	25,201
2011	6,376	8,015	14,391	10,776	25,167
2012	6,530	7,710	14,240	10,861	25,101
2013	6,657	7,466	14,123	10,975	25,098
2014	6,757	7,092	13,849	10,931	24,780
2015	6,818	6,600	13,418	10,978	24,396
2016	6,865	6,168	13,034	10,981	24,014
2017	6,902	5,757	12,659	10,606	23,264
2018	6,923	5,359	12,283	10,076	22,359
2019	6,928	4,969	11,897	9,778	21,675
2020	6,923	4,611	11,533	9,539	21,072
2021	6,845	4,460	11,306	9,179	20,484
2022	6,658	4,158	10,816	8,934	19,751
2023	6,405	3,873	10,278	8,716	18,994
2024	6,110	3,614	9,724	8,406	18,130
2025	5,763	3,378	9,141	8,073	17,214
2026	5,405	3,152	8,557	7,780	16,337
2027	5,047	2,942	7,989	7,532	15,521
2028	4,694	2,746	7,439	7,305	14,744
2029	4,349	2,561	6,910	7,097	14,007
2030	4,016	2,387	6,404	6,908	13,312
2031	3,699	2,224	5,923	6,737	12,660
2032	3,397	2,070	5,467	6,583	12,050
2033	3,112	1,924	5,036	6,443	11,479
2034	2,843	1,792	4,635	6,317	10,952
2035	2,465	1,670	4,135	6,090	10,225

Determination of the Economic Horizon of Midcontinent and Northern Rocky Mountain Gas Supplies



Determination of the Economic Horizon of Gulf Coast and LNG Gas Supplies



Southwest Gas Storage Company
Summary of ASL and Iowa Type Survivor Curve
Physical Life

Account Number	Description	Type Survivor Curve	Average Service Life
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Underground Storage Plant

350.2	Rights of Way	R ₅	51
351.01	Structures - Wells	R ₂	34
351.02	Structures - Compressor Station	R ₂	34
351.03	Structures - Measuring and Regulating	R ₂	34
351.04	Structures - Other Equipment	R ₂	34
352	Wells	R ₄	41
352.1	Leaseholds and Gas Rights	Forecast Forecast Forecast	
352.2	Reservoirs		
352.3	Non Recoverable Natural Gas		
353	Lines	S ₅	39
354	Compressor Station Equipment	R ₂	33
355	Other Equipment (M&R)	R ₂	30
356	Purification Equipment	S ₅	26
357	Other Equipment	R _{2.5}	28

Physical Lives of Storage Facilities

Industry Average

	Average Service Life <u>Years</u>
Rights of Way	51
Structures	34
Wells	41
Lines	39
Compressor Station Equipment	33
Measuring & Regulating Equip.	30
Purification Equipment	26
Other Equipment	28

Account 351 Structures

		Average Service Life	Depreciable Plant	Weight ASL
AGA Survey				
Columbia of Pa		40	194	7760
ANR		43.5	14,218	618483
Central Illinois Light		30	1,701	51030
Consumers Power				0
	351.20	45	6,755	303975
	351.30	45	4	180
43.33333	351.40	40	2,914	116560
Indiana Gas		25	1,207	30175
Michigan Consolidated Gas		30	2,563	76890
Northern Illinois Gas		30	11,972	359160
Northern Indiana Public Service		25	3,535	88375
Peoples Gas Light & Coke		35	3,856	134960
United Gas Pipe Line Co.		55.6	2,998	166688.8
Public Service Company of Colorado		25	1,840	46000
Southern California Gas Company		43	22,733	977519
Washington Natural Gas Co.				0
	351.1	10.6	26	275.6
	351.2	9.5	331	3144.5
	351.3	17.2	2	34.4
11.5	351.4	8.7	47	408.9
Canadian W. Natural Gas Co. LTD		30	3,424	102720
Northwest Utilities, Edmonton		30	3,043	91290
Weighted Average		38.09	83,363	3,175,629
Weighted Avg-WO ANR and United		36.14	66,147	2,390,457
Arithmetic Average		30.905		
Arithmetic Avg-WO Peoples, ANR and United		28.47		
By Company		31.07		
Other Observations				
Columbia Gas		39.33		
Koch		68		
Average All Ex ANR, Peoples and United		33.58		
Average All Ex ANR, Peoples and United and Koch		30.94		

Account 352 Wells

	Average Service Life	Depreciable Plant	Weight ASL
AGA Survey			
Columbia of Pa	56	968	54208
ANR	43.5	85,567	3722164.5
Central Illinois Light	30	19,574	587220
Consumers Power			0
	50	3,433	171650
	50	16,077	803850
50	50	11,053	552650
Indiana Gas	25	26,199	654975
Michigan Consolidated Gas			0
352.00	35	20,258	709030
352.10	50	181	9050
38.33333 352.30	30	265	7950
North Shore Gas Company	35	8,758	306530
Northern Illinois Gas	45	249,571	11230695
Northern Indiana Public Service	29	43,434	1259586
Peoples Gas Light & Coke	35	140,173	4906055
United Gas Pipe Line Co.	55.6	23,040	1281024
Public Service Company of Colorado		1,840	0
	25	3319	82975
37.5	50	167	8350
Southern California Gas Company	29	173,345	5027005
Washington Natural Gas Co.			
352.00	13.7	3,679	50402.3
352.20	15.8	741	11707.8
12.6 352.30	8.3	1,195	9918.5
Northwest Utilities, Edmonton			
352.10	50	16,533	826650
45 352.20	40	4,084	163360
Weighted Average	38.01	853,454	32,437,006
Weighted Avg-WO ANR and United	36.83	744,847	27,433,818
Arithmetic Average	37.00		
Arithmetic Avg-WO Peoples, ANR and United	35.80		
By Company and Acct			
By Company	36.04		
Other Observations			
Columbia Gas	56		
National Fuel	45.5		
Consolidated Natural Gas Corporation	55		
Colorado Interstate Gas Company	56		
Questar 1	40		
Questar 2	16		
ANR Storage Company	56		
Koch	55		
Average	47.44		
Average All Ex ANR, Peoples and United	40.60		
Average All Ex ANR, Peoples and United and Koch	39.84		

Account 353 Lines

	Average Service Life	Depreciable Plant	Weight ASL
AGA Survey			
Columbia of Pa	58	968	56144
ANR	43.5	85,567	3722164.5
Central Illinois Light	30	19,574	587220
Consumers Power	55		0
Indiana Gas	30	26,199	785970
Michigan Consolidated Gas	31		0
 Northern Illinois Gas	 45	 249,571	 11230695
Northern Indiana Public Service	28	43,434	1216152
Peoples Gas Light & Coke	35	140,173	4906055
United Gas Pipe Line Co.	55.6	23,040	1281024
Public Service Company of Colorado	30	1,840	55200
Southern California Gas Company	22	173,345	3813590
Washington Natural Gas Co.	15.2		
Canada Western Natural Gas Co., LTD	55		
Northwest Utilities, Edmonton	50		
 Weighted Average	 36.21	 763,711	 27,654,215
 Weighted Avg-WO ANR and United	 34.58	 655,104	 22,651,026
 Arithmetic Average	 38.89		
 Arithmetic Avg-WO Peoples, ANR and United	 37.43		
 Other Observations			
Columbia Gas	48		
National Fuel	35		
Consolidated Natural Gas Corporation	40		
Colorado Interstate Gas Company 1	48		
Colorado Interstate Gas Company 2	48		
Questar 1	35		
Questar 2	35		
ANR Storage Company	48		
Koch			
Average	42.13		
 Average All Ex ANR, Peoples and United			
Average All Ex ANR, Peoples and United	39.31		
Average All Ex ANR, Peoples and United and Koch	39.31		

Account 354 Compressor Station Equipment

	Average Service Life	Depreciable Plant	Weight ASL
AGA Survey			
Columbia of Pa	46	968	44528
ANR	43.5	85,567	3722164.5
Central Illinois Light	22	19,574	430628
Consumers Power	35		0
Indiana Gas	20	26,199	523980
Michigan Consolidated Gas	40		0
Northern Illinois Gas	30	249,571	7487130
Northern Indiana Public Service	31	43,434	1346454
Peoples Gas Light & Coke	35	140,173	4906055
United Gas Pipe Line Co.	55.6	23,040	1281024
Public Service Company of Colorado	30	1,840	55200
Southern California Gas Company	33	173,345	5720385
Washington Natural Gas Co.	14.7		
Canada Western Natural Gas Co., LTD	45		
Northwest Utilities, Edmonton	40		
Weighted Average	33.41	763,711	25,517,549
Weighted Avg-WO ANR and United	31.31	655,104	20,514,360
Arithmetic Average	34.72		
Arithmetic Avg-WO Peoples, ANR and United	32.23		
Other Observations			
Columbia Gas	40		
National Fuel	25		
Consolidated Natural Gas Corporation	30		
Colorado Interstate Gas Company	40		
Colorado Interstate Gas Company	40		
Questar 1	25		
Questar 2	25		
ANR Storage Company	40		
Koch	40		
Average	33.89		
Average All Ex ANR, Peoples and United	32.94		
Average All Ex ANR, Peoples and United and Koch	32.59		

Account 355 Measuring and Reg Equipment

	Average Service Life	Depreciable Plant	Weight ASL
AGA Survey			
Columbia of Pa	36	968	34848
ANR	43.5	85,567	3722164.5
Central Illinois Light	22	19,574	430628
Consumers Power	40		0
Indiana Gas	20	26,199	523980
Michigan Consolidated Gas	30		0
Northern Illinois Gas	30	249,571	7487130
Northern Indiana Public Service	28	43,434	1216152
Peoples Gas Light & Coke	35	140,173	4906055
United Gas Pipe Line Co.	55.6	23,040	1281024
Public Service Company of Colorado	30	1,840	55200
Southern California Gas Company	38	173,345	6587110
Washington Natural Gas Co.	15.9		
Canada Western Natural Gas Co., LTD	32		
Northwest Utilities, Edmonton	17.5		
Weighted Average	34.36	763,711	26,244,292
Weighted Avg-WO ANR and United	32.42	655,104	21,241,103
Arithmetic Average	31.57		
Arithmetic Avg-WO Peoples, ANR and United	28.28		
Other Observations			
Columbia Gas	35		
National Fuel			
Consolidated Natural Gas Corporation	35		
Colorado Interstate Gas Company	35		
Questar 1			
Questar 2			
ANR Storage Company	35		
Koch	33		
Average	34.6		
Average All Ex ANR, Peoples and United	30.14		
Average All Ex ANR, Peoples and United and Koch	29.96		

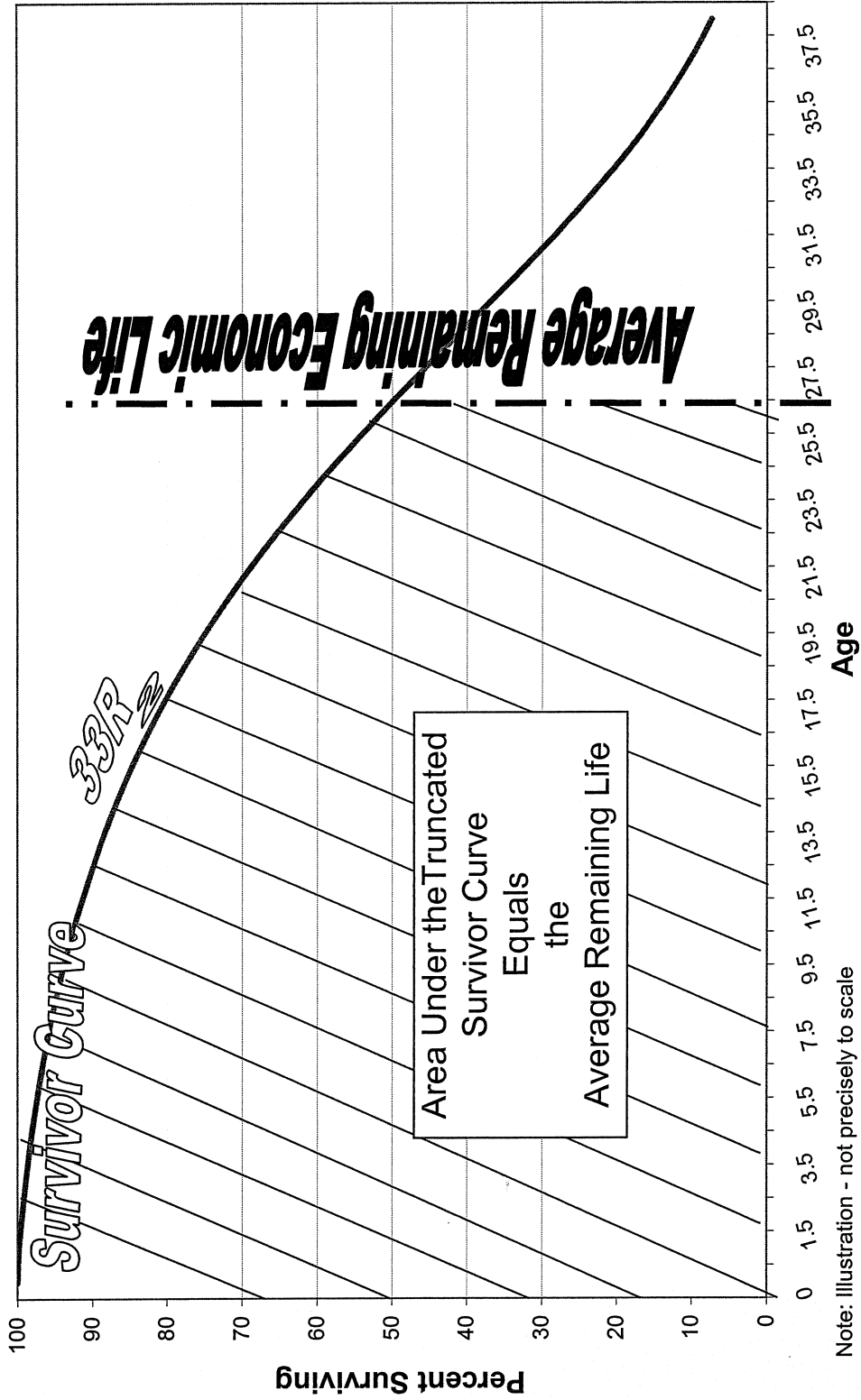
Account 356 Purification Equipment

	Average Service Life	Depreciable Plant	Weight ASL
AGA Survey			
ANR	43.5	85,567	3722164.5
Central Illinois Light	22	19,574	430628
Consumers Power	32		0
Indiana Gas	20	26,199	523980
Michigan Consolidated Gas	30		0
Northern Illinois Gas	30	249,571	7487130
Northern Indiana Public Service	27	43,434	1172718
Peoples Gas Light & Coke	35	140,173	4906055
United Gas Pipe Line Co.	55.6	23,040	1281024
Public Service Company of Colorado	30	1,840	55200
Southern California Gas Company	25	173,345	4333625
Washington Natural Gas Co.	13.2		
Weighted Average	31.35	762,743	23,912,525
Weighted Avg-WO ANR and United	28.91	654,136	18,909,336
Arithmetic Average	30.28		
Arithmetic Avg-WO Peoples, ANR and United	25.47		
Other Observations			
Columbia Gas	24		
National Fuel	24		
Consolidated Natural Gas Corporation			
Colorado Interstate Gas Company	25		
Questar 1	24		
Questar 2	27		
ANR Storage Company	24		
Koch	45		
Average	27.57		
Average All Ex ANR, Peoples and United	26.39		
Average All Ex ANR, Peoples and United and Koch	25.15		

Account 357 Other Equipment

	Average Service Life	Depreciable Plant	Weight ASL
AGA Survey			
Central Illinois Light	22	19,574	430628
Consumers Power	33		0
 Northern Illinois Gas	 30	 249,571	 7487130
Peoples Gas Light & Coke	35	140,173	4906055
United Gas Pipe Line Co.	55.6	23,040	1281024
Public Service Company of Colorado	15	1,840	27600
Southern California Gas Company	34	173,345	5893730
Washington Natural Gas Co.	16.8		
Canadian Western Natural Gas Co., Ltd	35		
Northwest Utilities, Edmonton	40		
 Weighted Average	 32.96	 607,543	 20,026,167
 Weighted Avg-WO ANR and United	 32.07	 584,503	 18,745,143
 Arithmetic Average	 31.64		
 Arithmetic Avg-WO Peoples, ANR and United	 28.23		
Other Observations			
Columbia Gas	22.33		
National Fuel			
Consolidated Natural Gas Corporation			
Colorado Interstate Gas Company			
Questar 1			
Questar 2			
ANR Storage Company			
Koch			
Average All Ex ANR, Peoples and United		27.57	

Survivor Curve
Account 354 Storage Compressor Station Equip



Southwest Gas Storage Company

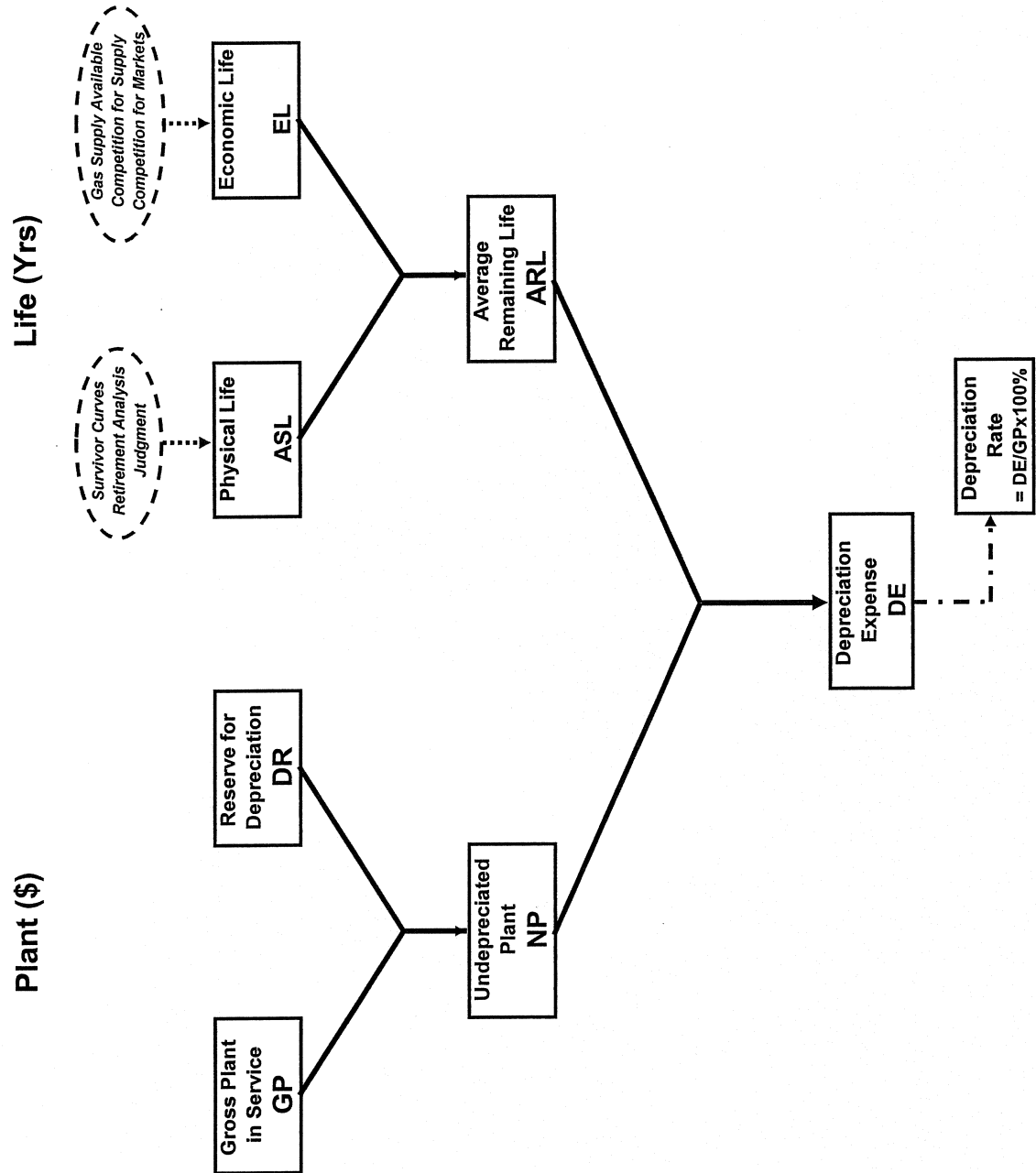
Average Remaining Lives

Account Number	Description	Average Remaining Life
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Underground Storage Plant

350.2	Rights of Way	18.7
351.01	Structures - Wells	9.6
351.02	Structures - Compressor Station	11.1
351.03	Structures - Measuring and Regulating	10.3
351.04	Structures - Other Equipment	10.9
352	Wells	15.0
352.1	Leaseholds and Gas Rights	28.0
352.2	Reservoirs	28.0
352.3	Non Recoverable Natural Gas	28.0
353	Lines	15.9
354	Compressor Station Equipment	13.6
355	Other Equipment	9.9
356	Purification Equipment	3.6
357	Other Equipment	5.8

Depreciation Analysis



Southwest Gas Storage Company

DETERMINATION OF THE DEPRECIATION RATE
UNDERGROUND STORAGE PLANT

Account No.	Description	Gross Depreciable Plant Investment Dec 31, 2006 and as Adjusted	Accumulated Reserve for Depreciation Dec 31, 2006 and as Adjusted	Net Depreciable Plant Dec 31, 2006 and as Adjusted	Average Remaining Life Years	Indicated Depreciation Expense \$	Depreciation Rate %
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Storage Plant - Underground

2006-6-22

350.2	Rights of Way	336,405	307,860	28,545	18.7	1,526	
351.1	Structures - Wells	73,537	67,020	6,517	9.6	679	
351.2	Structures - Compressor Station	8,189,294	6,697,826	1,491,468	11.1	134,366	
351.3	Structures - Measuring and Regulating	620,962	540,833	80,129	10.3	7,780	
351.4	Structures - Other	2,664,382	2,207,449	456,933	10.9	41,920	
352	Wells	40,488,601	32,698,884	7,789,717	15.0	519,314	
352.1	Leaseholds and Gas Rights	3,207,191	3,008,988	198,203	28.0	7,079	
352.2	Reservoirs	16,837,768	13,900,399	2,937,369	28.0	104,906	
352.3	Non Recoverable Natural Gas	8,762,277	7,492,386	1,269,891	28.0	45,353	
353	Lines	27,658,832	18,333,685	9,325,147	15.9	586,487	
354	Compressor Station Equipment	37,009,473	27,634,823	9,374,650	13.6	689,313	
355	Other Equipment (M & R)	4,052,995	3,405,819	647,176	9.9	65,371	
356	Purification Equipment	1,723,926	1,428,724	295,202	3.6	82,001	
357	Other Equipment	688,457	465,347	223,110	5.8	38,467	
		152,314,100		34,124,057		2,324,563	
	Additions	3,801,162		3,801,162	27.5	138,224	
	Adjust for Additional Non-recoverable Base Gas	28,128,369		28,128,369	28.0	1,004,585	
	Retirements	750,000	750,000				
	Subtotal	183,493,631	117,440,043	37,925,219		3,467,372	1.89%
		152,314,100	118,190,043	34,124,057			

2007-7-20

350.2	Rights of Way	336,405	309,386	27,019	17.9	1,509	
350.1	Structures - Wells	73,537	67,699	5,838	8.8	663	
351.2	Structures - Compressor Station	8,189,294	6,832,192	1,357,102	10.3	131,757	
351.3	Structures - Measuring and Regulating	620,962	548,613	72,349	9.5	7,616	
351.4	Structures - Other	2,664,382	2,249,369	415,013	10.1	41,090	
352	Wells	40,488,601	33,218,198	7,270,403	14.2	512,000	
352.1	Leaseholds and Gas Rights	3,207,191	3,016,067	191,124	27.0	13,459	
352.2	Reservoirs	16,837,768	14,005,305	2,832,463	27.0	104,906	
352.3	Non Recoverable Natural Gas	8,762,277	7,537,739	1,224,538	27.0	45,353	
353	Lines	27,658,832	18,920,172	8,738,660	15.1	578,719	
354	Compressor Station Equipment	37,009,473	28,324,136	8,685,338	12.8	678,542	
355	Other Equipment	4,052,995	3,471,190	581,805	9.1	63,935	
356	Purification Equipment	1,723,926	1,510,725	213,201	3.0	71,067	
357	Other Equipment	688,457	503,814	184,643	5.1	36,204	
	Subtotal	152,240,563	120,514,606	31,799,494		2,286,823	
	Plant Additions Balance @ 12/31/07	11,241,162	138,224	11,102,938	26.5	418,979	
	Adjust for Additional Non-recoverable Base Gas	28,128,369	1,004,585	27,123,784	27.0	1,004,585	
	Plant Retirements Balance @ 12/31/07	1,500,000	1,500,000				
	2007 Subtotal	190,110,094	122,014,606	42,902,432		3,710,386	1.95%

2008-8-09

350.2	Rights-of-Way	336,405	310,896	25,509	17.1	1,492	
350.1	Structures - Compressor	73,537	68,362	5,175	8.0	647	
351.2	Structures - Compressor	8,189,294	6,963,950	1,225,344	9.5	153,168	
351.3	Structures - Measuring and Regulating	620,962	556,228	64,734	8.7	6,814	
351.4	Structures - Other	2,664,382	2,290,460	373,922	9.3	42,980	
352	Wells	40,488,601	33,730,199	6,758,402	13.4	504,358	
352.1	Leaseholds and Gas Rights	3,207,191	3,029,526	177,665	26.0	6,833	
352.2	Reservoirs	16,837,768	14,110,211	2,727,557	26.0	104,906	
352.3	Non-recoverable Natural Gas	8,762,277	7,583,093	1,179,185	26.0	45,353	
353	Lines	27,658,832	19,498,891	8,159,941	14.3	570,625	
354	Compressor Stations	37,009,473	29,002,677	8,006,796	12.0	667,233	
355	Meas. & Regulating Sta. Equip.	4,052,995	3,535,125	517,870	8.9	58,188	
356	Purification Equipment	1,723,926	1,581,792	142,134	2.5	56,854	
357	Other Equipment	688,457	540,019	148,438	4.4	33,736	
	2008 Subtotal	152,314,100	122,801,429	29,512,671		2,253,187	
	Plant Additions Balance @ 12/31/08	16,537,162	557,203	15,979,959	25.5	626,665	
	Adjust for Additional Non-recoverable Base Gas	28,128,369	2,009,169	26,119,200	26.0	1,004,585	
	Plant Retirements Balance @ 12/31/08	2,250,000	2,250,000				
	Subtotal	194,729,631	250,419,229	101,124,502		3,884,436	1.99%

COMPOSITE DEPRECIATION RATE 1.95%

SOUTHWEST GAS STORAGE COMPANY

Summary of Terminal Negative Salvage Estimate

Source: James S. Taylor

	Underground Storage Field			Total \$
	Waverly \$	Howell \$	Borchers North \$	
Retirement Process	10,973,392	14,804,329	9,801,235	38,420,439
Gross Salvage	(658,433)	(924,380)	(816,291)	(2,605,091)
Contingency	1,097,339	1,480,433	980,123	3,842,043
Grand Total	11,412,298	15,360,382	9,965,067	39,657,391

Underground Storage DETERMINATION OF THE AVERAGE REMAINING LIFE OF INTERIM NEGATIVE SALVAGE

		Normal Retirements							Estimated Negative Salvage	Number of Years Remaining In Service	Weight	
		Acct 351	Acct 352	Acct 353	Acct 354	Acct 355	Acct 356	Acct 357				Total
1	2006	236,539	671,483	352,831	795,078	108,415	93,094	29,742	2,055,932	428,695	0.5	1,027,966
2	2007	246,138	728,406	337,073	837,367	110,675	101,046	29,616	2,148,984	446,126	1.5	3,223,477
3	2008	255,646	782,698	320,201	880,609	112,445	104,304	28,662	2,239,154	462,069	2.5	5,597,886
4	2009	264,725	831,740	310,211	925,507	113,644	102,206	26,970	2,332,183	477,789	3.5	8,162,641
5	2010	273,504	876,179	309,317	971,905	114,408	95,065	24,620	2,430,904	494,007	4.5	10,939,069
6	2011	281,785	911,666	325,375	1,019,871	114,630	84,089	21,958	2,538,697	511,895	5.5	13,962,834
7	2012	289,505	942,728	360,737	1,067,608	114,246	70,970	19,120	2,660,579	532,775	6.5	17,293,765
8	2013	296,496	966,029	418,573	1,114,098	113,284	57,289	16,392	2,795,196	556,844	7.5	20,963,973
9	2014	302,743	986,737	500,315	1,156,455	111,696	44,306	13,842	2,946,250	585,112	8.5	25,043,121
10	2015	307,969	1,006,718	599,292	1,192,422	109,424	32,874	11,584	3,106,401	616,086	9.5	29,510,811
11	2016	312,182	1,025,225	716,619	1,219,044	106,495	23,475	9,655	3,273,071	649,530	10.5	34,367,244
12	2017	315,115	1,048,602	833,432	1,233,239	102,908	16,250	8,087	3,430,389	681,728	11.5	39,449,474
13	2018	316,661	1,074,949	951,365	1,233,042	98,719	11,132	6,966	3,576,018	712,395	12.5	44,700,224
14	2019	316,705	1,112,999	1,046,386	1,216,561	93,916	7,927	6,236	3,692,651	737,222	13.5	49,850,795
15	2020	315,039	1,152,741	1,118,364	1,183,143	88,668	6,316	5,804	3,769,286	754,188	14.5	54,654,652
16	2021	311,422	1,196,829	1,152,723	1,133,714	83,094	5,927	5,506	3,794,688	760,436	15.5	58,817,662
17	2022	305,856	1,234,582	1,151,219	1,069,691	77,263	71,380	5,398	3,761,347	754,609	16.5	62,062,223
18	2023	298,266	1,263,394	1,108,606	994,033	69,433	7,091	5,487	3,664,299	735,436	17.5	64,125,237
19	2024	288,668	1,277,646	1,036,934	910,647	65,725	7,958	5,609	3,513,895	705,253	18.5	65,007,050
20	2025	277,177	1,273,896	933,850	823,237	60,057	8,682	5,613	3,308,160	663,399	19.5	64,509,118
21	2026	263,901	1,251,005	822,439	736,027	54,494	9,125	5,474	3,073,371	615,641	20.5	63,004,110
22	2027	249,333	1,210,501	700,376	652,637	49,108	9,185	5,192	2,812,848	562,409	21.5	60,476,226
23	2028	233,430	1,151,338	587,889	575,046	43,768	8,799	4,784	2,547,703	508,418	22.5	57,323,307
24	2029	216,717	1,081,037	484,567	504,846	38,632	7,964	4,269	2,287,167	455,354	23.5	53,748,427
25	2030	199,462	999,294	400,600	442,473	33,811	6,753	3,705	2,041,830	405,690	24.5	50,024,828
26	2031	182,063	911,798	336,886	388,341	29,302	5,320	3,118	1,819,088	360,862	25.5	46,386,754
27	2032	164,756	822,767	293,909	341,439	25,244	3,866	2,557	1,622,872	321,719	26.5	43,006,101
28	2033	147,934	731,853	272,807	302,500	21,822	2,565	2,032	1,455,097	288,750	27.5	40,015,097
29	2034	131,564	646,826	269,490	271,018	19,094	1,538	1,567	1,318,899	262,358	28.5	37,588,613
30	2035	115,915	562,880	283,633	247,499	16,724	824	1,163	1,209,926	241,703	29.5	35,692,819
30 Year Total		7,717,219	29,734,545	18,336,021	25,439,098	2,303,092	942,254	320,727	81,226,883	16,288,501	14.29	1,160,535,503
28 Year Total		7,321,806	27,792,986	17,510,091	24,618,081	2,245,451	937,327	315,965	77,242,964	15,495,689	13.56	1,047,238,973
24 Year Total		6,775,524	25,059,128	16,478,695	23,445,827	2,157,095	921,388	306,585	71,759,174	14,407,418	12.65	907,821,290

SOUTHWEST GAS STORAGE COMPANY

Determination of the Cost of Removal of Interim Retirements Storage Field Lines

		Cost of Removal and Salvage					Allocated to interim Retirement (f)	Cost of Removal Interim Retirement (g)
		Waverly (a)	Howell (b)	Borchers North (c)	North Hopeton (d)	Total (e)		
I.	Pipeline Segment in Field							
	Clean and Purge	\$ 129,308	\$ 184,960	\$ 125,486	\$ 39,837	\$ 479,591	0.75	\$ 359,693
	Remove Field Line	\$ 1,143,808	\$ 4,828,277	\$ 3,203,874	\$ 242,392	\$ 9,418,351	0.50	\$ 4,709,176
	Pipe Handling and Storage	\$ 172,432	\$ 420,172	\$ 383,171	\$ 80,046	\$ 1,055,821	1.00	\$ 1,055,821
	Sub Total	\$ 1,445,548	\$ 5,433,409	\$ 3,712,531	\$ 362,275	\$ 10,953,763		\$ 6,124,690
II.	Salvage	\$ 116,520	\$ 526,080	\$ 364,080	\$ 18,420	\$ 1,025,100		
III.	Contingency	\$ 144,555	\$ 543,341	\$ 371,253	\$ 36,228	\$ 1,095,376		\$ 1,095,376
IV.	Field Line Investment	\$ 6,807,119	\$ 6,976,577	\$ 10,271,709	\$ 1,559,640	\$ 25,615,045		
V.	Negative Salvage	12.8%	42.9%	20.3%	16.0%	23.0%		24.2%

Gross Plant	Interim Retirements	Total Interim Ret To Gross Plant	Gross Plant Subject to Final Retirement	From Southwest Witness James Taylor's TNS Study			TNS of Current Plant			
				Gross Salvage	Line Pack Credit	Overheads (Included in Estimate)	Demolition/Abandon Cost	Adj Gross Salvage Amount	Adj Cost of Final Retirement	Negative Salvage Cost Final Retirement
\$	\$	Gross Plant	\$	\$		\$	\$	\$	\$	\$
123,506,864	77,242,964	0.63	46,263,900	2,605,091	-	42,262,482	975,830	15,830,920	14,855,090	
123,506,864	77,242,964			2,605,091	-	42,262,482	975,830	15,830,920	14,855,090	14,855,090

Southwest Gas Storage Company

Underground Storage Plant

AVERAGE REMAINING LIFE OF NEGATIVE SALVAGE OF PLANT SUBJECT TO RETIREMENT

	Net Negative Salvage Cost \$	Average Number of Years to Retirement Years	Weight Direct \$	Reciprical \$
Interim Retirements	15,495,689	13.56	210,086,315	1,142,942
Final Closure	14,855,090	28	415,942,517	530,539
Total and Composite Direct Wt.	30,350,779	20.63	626,028,832	1,673,481
Reciprical Wt.		18.14		

SOUTHWEST GAS STORAGE COMPANY

DETERMINATION OF NEGATIVE SALVAGE RATE **Underground Storage Plant**

1	Total Depreciable Underground Storage Plant (\$)	152,314,100
2	Negative Salvage (\$)	30,350,779
3	Accumulated Reserve for Negative Salvage (\$)	-
4	Unaccrued Negative Salvage (\$)	30,350,779
5	Average Remaining Life (Years)	20.6
6	Annual Accrual (\$)	1,471,449
7	Negative Salvage Rate (%)	0.97%

EXHIBIT NO. SGS-54
Docket No. RP07-____-000

Assessment of the Availability
Of Natural Gas in
The Northern Rocky Mountain Area
The Midcontinent Area
Gulf Coast Area

Edward H. Feinstein

1 **I. INTRODUCTION**

2
3 Edward H. Feinstein has prepared this report on conventional natural
4 gas supplies of the Northern Rocky Mountain Area, the Midcontinent Area and
5 the Gulf Coast Area. In this report, specific reviews were made of the history,
6 gas production, estimates of proven reserves and estimates of undiscovered
7 resources.

8 The principal purpose of this report is to present estimates of the
9 availability or productive capability of natural gas in certain regions of the
10 Rocky Mountain Area, the Midcontinent Area and the Gulf Coast Area . An
11 assessment of the unconventional resource, coal-bed methane in the Rocky
12 Mountain Area is also included in this report. Forecasts of the area-wide
13 natural gas productive capability were based upon estimates of proven
14 reserves, discovery process estimates of reserve additions, pipeline connection
15 parameters and deliverability profiles. Discovery process is the relationship
16 between the efforts (drilling) and the potential for natural gas discoveries.

17 **II. SUMMARY AND CONCLUSIONS**

18 The gas supply regions of the Northern Rocky Mountain Area are in
19 both an intermediate and mature stage of development. The Midcontinent
20 Area, with its Hugoton-Anadarko Basin, the Permian Basin as the anchor, is in
21 its mature stage of development. Included in this broad area is the Fort Worth
22 Basin, with its presently active Barnett Shale play. The Hugoton-Anadarko
23 Basin, Permian Basin, onshore and offshore areas of the Gulf Coast is also in

1 its mature stage and its large production has plateaued. The assessment of
2 gas supply herein is based on three ingredients: remaining reserves, reserves
3 appreciation and undiscovered resources. Remaining reserves are the proved
4 and economically producible gas discoveries. Reserves appreciation are
5 resources believed to exist that are directly related to reserves already
6 discovered. Undiscovered resources are estimated gas accumulations that are
7 believed to exist, but have not yet been proven by drilling.

8 The productive capacities of proven gas reserves of each producing
9 region of the of all the listed areas vary considerably. Reserves-to-production
10 ratios in each area presently are at their lowest level, reflecting only modest
11 surplus pipeline gas.

12 Estimates of future annual gas discoveries were made employing a
13 discovery - process model as described below. Productive capacity decline
14 rates were applied to determine the availability of gas from new supply
15 sources.

16 The availability of supplies from future sources was added to the
17 availability of current proven sources to arrive at the overall productive
18 capability of natural gas supplies from the various areas.

19 These supply areas are currently reliable, active and viable in providing
20 adequate throughput for the network of pipelines connected to them. In the
21 long-term, however, the current grade of natural gas accumulations will be
22 exhausted, giving way to the discovery of smaller deposits. The result will be a

1 gradual decline in the productive capability from existing and future connected
2 supply sources.

3 **III(A). BACKGROUND – NORTHERN ROCKY MOUNTAIN AREA**

4 The Northern Rocky Mountain area is made up of the states of
5 Colorado, Utah, Wyoming, Montana and North Dakota. The Rocky Mountain
6 area of Colorado, Utah and Wyoming is one of only two oil and gas provinces
7 in North America that have been growing in gas production over the past 10
8 years. Although relatively small, productive areas of Montana and North
9 Dakota, while not in a growth stage, presently remain in a constant state of gas
10 discoveries and production. The Rocky Mountain region will continue to grow
11 in gas production for 10 more years. The Rocky Mountain area is a large, gas
12 prone, geologically heterogeneous area that contains numerous gas productive
13 basins. Numerous oil and gas prone formations and prospective reservoirs are
14 present. Productive reservoirs include carbonates (limestone) and sandstones
15 with all types of porosity and permeability as well as naturally fractured
16 reservoirs and coalbed methane reservoirs. The Potential Gas Committee
17 (PGC) has estimated (2004) potential gas resources of 123 Tcf.

18 A challenge for certain gas resources in the region is to exploit
19 technically available gas in locations where reserves are characterized by
20 “tight” matrix porosity and permeability, naturally fractured reservoirs and
21 coalbed methane and make them economically recoverable resources.

1 **III(B). BACKGROUND – MIDCONTINENT AREA**

2 The Midcontinent Area is dominated by the Hugoton-Anadarko and the
3 Permian Basins, both of which are prolific gas producing areas. Additionally,
4 the Fort Worth Basin province is believed to hold significant gas potential. The
5 Midcontinent area is one of the largest natural gas producing areas and
6 currently ranks as one of the leading U.S. supply areas in both production and
7 remaining resources. There is, however, very few, if any, new field discoveries
8 presently in this region. Most new field discoveries will come from the deep
9 portions of the basin. Reserve additions, especially in strata laying above
10 15,000 feet are due essentially to growth in existing reserves from field
11 extensions. Existing production in this area is in an overall downward trend.

12 **III(C). BACKGROUND – GULF COAST AREA**

13 The Gulf Coast area is the largest producing region in North America.
14 All areas and regions of the Gulf Coast area, with the exception of the
15 deepwater slope of the Gulf of Mexico, are extensively explored. While the
16 offshore portion of the basin grew strongly in the 1990s, that growth has
17 slowed considerably as the basin rapidly matured. An indication of such a
18 mature stage is the average well productivity, which has decreased
19 dramatically and the slope of the overall decline rates has steepened. The
20 remaining undiscovered conventional resources are found in increasingly
21 smaller average pool sizes.

IV. METHODOLOGY

Proven Reserves

An analysis of the producibility of proven gas reserves was made using information obtained from the Energy Information Administration (EIA) and the Potential Gas Committee (PGC). EIA's proven reserves are as of the end of 2004. This coincides with the date of the PGC study. The productive availability of those proven reserves was obtained from data assembled by the (PGC) and extrapolated employing a constant percentage decline until the reserves are exhausted. The proven gas reserves were obtained from EIA, which in turn collected the data from producers. The PGC provided the production rate of those reserves.

Future Reserve Additions

A characteristic observed in the petroleum producing areas of the North American gas supply areas is a rapid drop off in size from the largest known field to the smaller ones. Hydrocarbon accumulations are the result of complex geological processes. Furthermore, the actual quantities of producible reserves are further defined on the basis of technological and economic considerations. As a consequence of all these independent influences and the multiplicative nature of the factors affecting the size of a gas accumulation, field sizes in producing basins are typically log normally distributed (Figure 1). That is, a few very large fields contain the bulk of the reserves and many, many small fields contain, in aggregate, a smaller portion of the reserves. Also,

1 another characteristic of gas supply basins is that large fields are discovered
2 early in the exploration process, and subsequent discoveries are smaller and
3 the product of increasingly greater efforts. This is demonstrated in illustrative
4 form in Figure 2.

5 Since some of the basins in the Rocky Mountain Area, unlike other producing
6 regions, contains both mature and intermediate supply regions, perhaps some
7 large field discoveries remain undiscovered and will become available for
8 exploitation and some portion of resource estimates may prove to have been
9 too optimistic.

10 The Finding Rate Methodology

11 One measure of the discoverability of resources is the rate at which
12 resources are found. This method compares the drilling footage in a particular
13 year with the related discoveries. This method depicts the normal stage of
14 events that take place when a gas-bearing province graduates past its initial
15 discovery stage and enters its more or less mature stage. The degree of
16 maturity of the producing life of the supply areas can be determined by
17 comparing the amount of gas resources already discovered with an estimate of
18 the ultimate resources.

19 The nature of oil and gas accumulations creates a distribution of fields
20 and reservoirs made up of a small number of large fields, a larger number of
21 medium size fields and a seemingly unending amount of small fields. The
22 Rocky Mountain Area, as well as the Midcontinent and Gulf Coast areas are no

1 exception. An example of the distribution of gas reserves in the a portion of the
2 Rocky Mountain Area, referred to as the Greater Green River Basin, is shown
3 on Figure 1. This is typical of the exploratory events of an oil and gas province.

4 The basic concept of this Finding Rate Methodology is shown on Figure
5 2. At times, the declining rate of effectiveness is mitigated by: better
6 technologies for discovery and resource recovery, greater understanding of the
7 geophysics, and reservoir performance of the field in the province. This
8 mitigation is also shown on Figure 2.

9 Advances in technology are, however, a double-edged sword with
10 respect to extending the life of gas resources and ultimately the life of
11 associated producing equipment and pipeline facilities. Exploration and
12 production (E&P) technology varies throughout the industry, from increasing
13 the success ratio in exploration to more efficient production techniques. While
14 some advances in technology may allow the commercialization of heretofore
15 unproduceable hydrocarbon deposits, most others relate to the profitability of
16 technically discoverable oil and gas resources. For example, four causes for
17 the accelerated production of a given gas resource in the Rocky Mountain area
18 relate to technology. They are:

- 19 • 3-D seismic
- 20 • Horizontal wells
- 21 • Efficient completion techniques
- 22 • General miscellaneous technology

1 An example of the effect of new geophysical technology (e.g. 3-D
2 seismic) on E&P is basically an improvement in the exploration success ratio.
3 With advances in geophysical technology, producers are better able to locate
4 oil and gas deposits and also to determine whether they should be explored or
5 bypassed as a viable project.

6 Technology advances do not come cheap. Its application must be in
7 terms of the potential value of the resource. This assessment takes into
8 account technology, in that the forecasts were based upon the employment of
9 various trends, which included advances in technology.

10 I first determined if the supply areas paralleled the premise of this model
11 (that large initial field discoveries give way to smaller ones). In addition to the
12 field size facts cited earlier, further analysis confirmed that indeed most of the
13 larger fields have been discovered as well as many of the medium size fields.
14 This can be observed by inspecting the relationship between the new fields
15 discovered and the exploratory efforts as shown on Figure 3.

16 This can also be seen by analysis of the finding rate methodology in
17 terms of exploratory effort. Most of the significant gas discoveries are actually
18 associated with fields previously discovered. See the historical data shown on
19 Tables 1 and 2, and Figure 3. The exploratory effect is the accumulation of
20 wells drilled over time. The above finding rate data is a 6-year snapshot of a
21 long trend from higher levels of how effective exploration and development was
22 in prior years. I observed both exploratory wells and development wells.

1 Development wells do not reflect the effort to find new discoveries. However,
2 they contribute significantly to the reserve base. "Results" (in terms of annual
3 gas discoveries) of the drilling effort are also shown on Tables 1 and 2 for all
4 the areas.

5 When these "results" or annual gas discoveries are divided by the
6 annual exploratory wells drilled, a more focused relationship develops as to the
7 size of the discovery for the effort expended. This confirms that the large fields
8 have already been discovered and that new discoveries are going to be
9 generally confined to a considerably more moderate size. This concept of
10 discoveries per well drilled is referred to by the EIA as the Finding Rate
11 Methodology.

12 The Finding Rate Methodology began in the late 1950s and early 1960s
13 and continues to be used today. The famous oil and gas forecaster, M. King
14 Hubbert developed various aspects of it and used it in his presentations and
15 forecasts. The renown petroleum engineer and recipient of the C. C. Uren
16 Award from the Society of Petroleum Engineers, J.J Arps also developed the
17 Finding Rate Methodology in the early 1960s, referring to it as the
18 Effectiveness of Exploration. The methodology was and still is employed
19 widely by those forecasting oil and gas resources. The EIA exclusively uses
20 the Finding Rate Methodology to forecast long range oil and gas discoveries in
21 its state-of-the art *Annual Energy Outlook* publication.

1 The model used the relationship between annual reserve additions and
2 both exploratory and development well drilling over time in years and
3 cumulative feet drilled from a base of 1990. For the most likely case, I
4 extrapolated the exploratory finding rate at a constant level using the 5-year
5 mean value developed in Tables 1 and 2 until a point is reached where 90
6 percent of the total endowment is reached. The total endowment is defined as
7 all the gas that will eventually be discovered (past discoveries plus the PGC's
8 estimates of potential resources). PGC's estimates of potential gas resources
9 for the Northern Rocky Mountain area are shown on Table 7. Table 8 shows
10 the total endowment as of 2004 for the gas provinces of Colorado, Utah and
11 Wyoming.

12 I used the same procedure for the finding rate of development drilling.

13 The most likely level represents the mean value of the finding rate from
14 2000 through 2004.

15 I employed a constant level of effectiveness until 90 percent of the
16 ultimate resources are discovered as I expect some occasional increases in
17 the finding rate due to forces not directly indicated in the data. As mentioned
18 earlier, any decline in the finding rate curve will be mitigated by technological
19 increases in the exploration and drilling techniques along with an increased
20 awareness of the geophysics and reservoir mechanics. Technological
21 increases are included in the 1990-2004 data. I am assuming that future
22 technological increases will occur at the same rate as in the historical statistics.

1 I found, in some cases unsurprisingly, that as drilling exceeds certain levels,
2 the finding rate declines. This is due most likely to the drilling of lower grade
3 prospects in a particular year. See Figures 8 and 9 for the historical
4 relationship between footage and finding rate. These relationships are shown
5 here to demonstrate the complexity of the drilling - discovery process. They,
6 however were not used in the forecast of gas discoveries. This is conservative,
7 as including such a potential relationship would lower the magnitude of future
8 gas discoveries.

9 I determined the future discoveries from exploratory drilling by applying a
10 representative constant level of drilling activity to the corresponding finding
11 rate. For my determination of the discoveries from development drilling, I also
12 applied a constant level of annual drilling activity, based upon analysis of the
13 most recent 6-year period, to reflect the development drilling activity response
14 to increases in the wellhead price of gas. This period included very significant
15 increases in the price of gas at the wellhead and only one modest decrease. I
16 believe that in the future such similar increases and decreases will occur
17 eventually leading to a further overall price increase. My choice of exploratory
18 and development drilling levels fully reflects an overall average price increase
19 over the pertinent period, all the while daily, monthly and yearly prices will
20 fluctuate both up and down. Specifically, based on my experience and studies,
21 I found a relationship to exist between the price of gas at the wellhead and
22 development drilling effort. No such clear relationship occurs for exploratory

1 drilling as drilling prospects differ considerably in many respects as well as
2 inherent risk factors. As such, many factors come into play with respect to the
3 exploratory drilling response. While an increase in wellhead gas prices is an
4 inducement to increase exploratory drilling efforts, the fact is that for the
5 producing areas involved in this proceeding, there is no clear and concise
6 relationship between wellhead price and the number of exploratory wells
7 drilled. The graphs shown on Figures 13 and 14, of wellhead gas price and
8 drilling effort, illustrate this point.

9 Exploratory wells differ considerably from development wells in the Rocky
10 Mountain, Midcontinent and Gulf Coast areas. Exploratory wells are relatively
11 high risk. They are drilled relatively far from existing discoveries. They are
12 high cost. Existing, in place, pipeline facilities may be lacking. They must rely
13 upon financing much different from development wells, e.g., the expenditure of
14 money for geological and geophysical studies. Many factors affect the decision
15 to drill exploratory wells, including, but not exclusively, the prevailing wellhead
16 price.

17 With respect to development wells and price, the annual relationship
18 between them is not sufficient to forecast future drilling efforts. Instead, I
19 employed high values of such efforts in my calculations. The Most Likely Case
20 level of wells drilled and footage attained was based on an average value for
21 the 2000-2005 period.

1 The Future Discoveries resulting from the application of the drilling effort
2 to the effectiveness of drilling in the Rocky Mountain area are shown on Table
3 3 for exploratory discoveries and Table 4 for development discoveries.

4 To determine the future gas availability, I applied to each determined
5 annual future reserve addition, a production rate derived by the Potential Gas
6 Committee from gas production data obtained from Petroleum
7 Information/Dwights LLG (See Figure 10).

8 This results in the production capacity from new reserves beginning in
9 2005 and 2006. I applied the same production rate profile to each future
10 amount of gas discoveries. Actually, because of the progressively lower
11 grade of gas deposits found in the future; and the new technology trending
12 towards achieving faster revenue payouts, I expect the decline rate of the
13 production rate profile to become steeper. This would tend towards faster
14 depletion of the future resources and eventually shortening the life of the
15 endowment of gas in those areas. By employing the current production profile
16 decline rate to each increment of future discoveries, the results are somewhat
17 conservative.

18 To the production profile of future reserves, I added the production
19 profile for the beginning of year 2004 proven (already discovered) gas
20 reserves. This is shown on Table 6.

21 Similar determinations were made for the Midcontinent Area and the
22 Gulf Coast Area. Information on gas production, reserve additions and wells

1 drilled in those areas was obtained from the same sources as the Northern
2 Rocky Mountain Area.

3 **V. DETERMINATION AND RESULTS --**
4 **NORTHERN ROCKY MOUNTAIN AREA**

5 The Northern Rocky Mountain area that I analyzed occupies the states
6 of Wyoming, Utah and Colorado. This is one of the major oil and gas
7 producing regions of the United States. Gas production will come from mostly
8 non-associated gas reservoirs and coal-bed methane deposits. New field
9 discoveries are expected to be found in deposits ranging from 1 to 200 Bcf,
10 with most in the 2 to 20 Bcf range. The profile of the future productive capacity
11 from this area is graphically illustrated on Figure 11.

12 The gas supply assessment of the Midcontinent and Gulf Coast Areas followed
13 the same approach and methodology. The development and results are
14 shown in Tables 9 through 12 and Figures 16 through 18 for the Gulf of Mexico
15 assessment; Tables 13 through 18 and Figures 19 through 23 for the onshore
16 Gulf Coast areas; and Tables 19 through 24 and Figure 24 for the Midcontinent
17 area.

18 Figures 11, 18, 22, 23 and 24 and Tables 12, 16, 18 and 21 show the
19 marketable gas capacity that could be available to Southwest Gas Storage
20 Company.

TABLES TO THE ASSESSMENT OF GAS SUPPLY

**Success Ratio and Effectiveness of Drilling
Exploratory Wells
Rocky Mountain Area
Colorado, Utah and Wyoming**

Year	Wells Drilled			Success Ratio	Gas Target Wells	Gas Target Footage 1,000 Ft	Gas Target Wells as a % of Total	Discoveries		Effectiveness	Cumulative Exploratory Wells	Effectiveness	Exploratory Wells Drilled	Cumulative Exploratory Footage
	Oil	Gas	Dry					Total Bcf	Per Gas Compl. Bcf/Well					
1990	112	332	420	0.514	646	1,982	74.77	835	2.52	1,292	646	1,292	646	1,982
1991	62	264	324	0.502	526	1,642	80.98	513	1.94	0.975	1,172	0.975	526	3,624
1992	47	182	315	0.421	432	1,329	79.48	993	5.46	2.297	1,605	2.297	432	4,954
1993	30	224	270	0.485	462	1,566	88.19	1,046	4.67	2.264	2,067	2.264	462	6,519
1994	37	437	212	0.691	632	1,447	92.19	960	2.20	1,518	2,699	1,518	632	7,966
1995	36	450	213	0.695	647	1,545	92.59	508	1.13	0.785	3,347	0.785	647	9,511
1996	38	279	186	0.630	443	1,287	88.01	688	2.47	1,554	3,789	1,554	443	10,798
1997	40	195	209	0.529	368	1,431	82.98	2,377	12.19	6,452	4,158	6,452	368	12,229
1998	40	294	201	0.624	471	1,901	88.02	1,352	4.60	2,871	4,629	2,871	471	14,131
1999	39	156	126	0.607	257	1,630	80.00	1,855	11.89	7,224	4,885	7,224	257	15,760
2000	27	90	118	0.498	181	1,285	76.92	3,051	33.90	16,878	5,066	16,878	181	17,045
2001	35	188	167	0.572	329	2,306	84.30	5,076	27.00	15,438	5,395	15,438	329	19,351
2002	18	131	92	0.618	212	1,464	87.92	4,735	36.15	22,347	5,607	22,347	212	20,815
2003	25	127	98	0.608	209	1,473	83.55	3,402	26.79	16,287	5,816	16,287	209	22,288
2004	14	170	61	0.751	226	1,438	92.39	4,669	27.46	20,627	6,042	20,627	226	23,727
2005	28	210	78	0.753	279	1,783	88.24	4,435	21.12	15,906	6,321	15,906	279	25,510

6- Year Average 239 1625 86 4228 29 18 18

Success Ratio and Effectiveness of Drilling
Development
Rocky Mountain Area
Colorado, Utah and Wyoming

Year	Wells Drilled			Success Ratio	Gas Target Wells	Gas Target Footage 1,000 Ft	Gas Target Wells as a % of Total	Discoveries		Effectiveness	Effectiveness Per Well Drilled	Cumulative Development Wells	Effectiveness	Gas Target Wells	Cumulative Development Footage
	Oil	Total						Total Bcf	Per Gas Compl. Bcf/Well						
		Gas	Dry												
1990	409	866	184	1,459	0.874	991	5,068	67.92	0.17	0.151	0.000153	991	0.151	991	5,068
1991	320	943	182	1,445	0.874	1,079	5,654	74.66	0.74	0.650	0.000602	2,070	0.650	1,079	10,722
1992	263	1,468	140	1,871	0.925	1,587	8,800	84.81	0.32	0.398	0.000251	3,657	0.398	1,587	19,522
1993	324	2,018	117	2,459	0.952	2,119	12,671	86.17	0.46	0.438	0.000206	5,775	0.438	2,119	32,193
1994	257	1,619	138	2,014	0.931	1,738	10,933	86.30	0.28	0.264	0.000152	7,514	0.264	1,738	43,126
1995	310	909	128	1,347	0.905	1,004	6,314	74.57	2.31	2.092	0.002082	8,518	2.092	1,004	49,440
1996	325	723	148	1,196	0.876	825	5,112	66.99	1.49	1.302	0.001578	9,343	1.302	825	54,552
1997	434	1,326	217	1,977	0.890	1,489	9,254	75.34	0.16	0.144	0.000097	10,833	0.144	1,489	63,806
1998	335	1,831	134	2,300	0.942	1,944	12,045	84.53	0.93	0.874	0.005121	12,777	0.874	1,944	75,851
1999	100	2,879	109	3,088	0.965	2,984	14,541	96.64	0.91	0.874	0.010090	15,761	0.874	2,984	90,393
2000	278	5609	129	6,016	0.979	5,732	27,817	95.28	0.38	0.370	0.019578	21,493	0.370	5,732	118,210
2001	169	6822	164	7,155	0.977	6,962	35,702	97.58	0.14	0.135	0.000019	28,475	0.135	6,962	153,912
2002	203	4435	124	4,762	0.974	4,554	23,891	95.62	0.21	0.202	0.000044	33,029	0.202	4,554	177,804
2003	388	4151	110	4,649	0.976	4,252	25,260	91.45	0.25	0.239	0.000056	37,280	0.239	4,252	203,063
2004	348	5357	103	5,808	0.982	5,454	36,224	93.90	-0.22	-0.220	(0.000040)	42,734	-0.220	5,454	241,287
2005	406	7595	143	8,144	0.982	7,731	54,320	94.93	0.13	0.123	0.000016	50,465	0.123	7,731	295,607
6-Year Average															
						5,784	34,202	95	0.145	0.141			0.141		

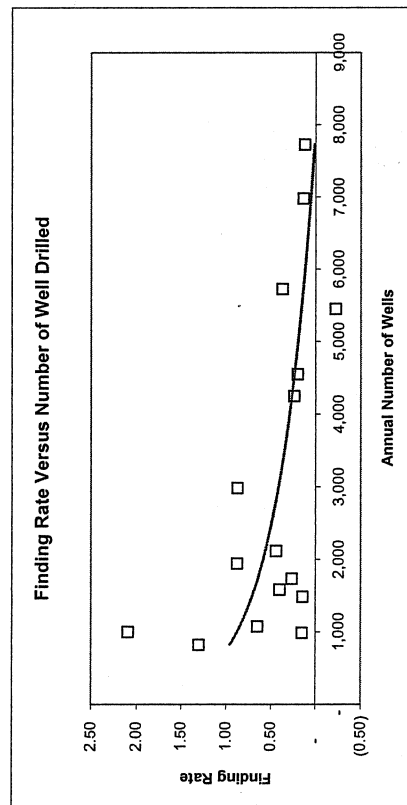
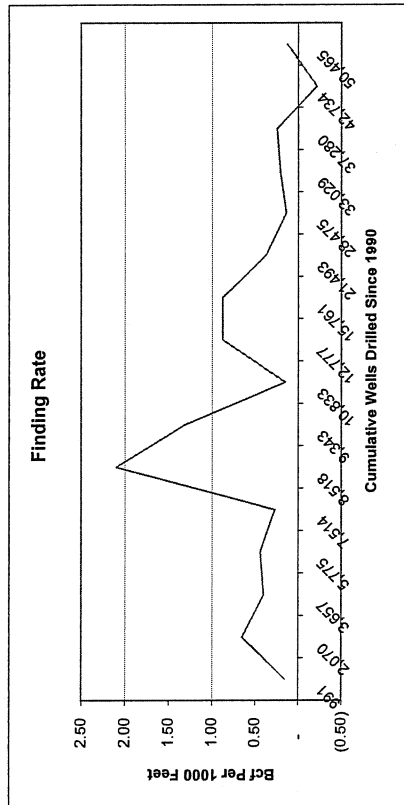
**DETERMINATION OF NEW RESERVE ADDITIONS
ROCKY MOUNTAIN AREA
Colorado, Utah and Wyoming
EXPLORATORY**

Year	Wells Drilled	Cumulative Wells	Effectiveness	Reserve Additions
			Bcf/1,000 Feet	Bcf
1990	646	646	1.29	835
1991	526	1,172	0.97	513
1992	432	1,605	2.30	993
1993	462	2,067	2.26	1,046
1994	632	2,699	1.52	960
1995	647	3,347	0.78	508
1996	443	3,789	1.55	688
1997	368	4,158	6.45	2,377
1998	471	4,629	2.87	1,352
1999	257	4,885	7.22	1,855
2000	181	5,066	16.88	3,051
2001	329	5,395	15.44	5,076
2002	212	5,607	22.35	4,735
2003	209	5,816	16.29	3,402
2004	226	6,042	20.63	4,669
2005	279	6,321	15.91	4,435
2006	279	6,600	17.91	4,995
2007	279	6,879	17.91	4,995
2008	279	7,157	17.91	4,995
2009	279	7,436	17.91	4,995
2010	279	7,715	17.91	4,995
2011	279	7,994	17.91	4,995
2012	279	8,273	17.91	4,995
2013	279	8,552	17.91	4,995
2014	279	8,830	17.91	4,995
2015	279	9,109	17.91	4,995
2016	279	9,388	17.91	4,995
2017	279	9,667	17.91	4,995
2018	279	9,946	17.91	4,995
2019	279	10,224	17.91	4,995
2020	279	10,503	17.91	4,995
2021	279	10,782	16.12	4,495
2022	279	11,061	14.51	4,046
2023	279	11,340	13.06	3,641
2024	279	11,619	11.75	3,277
2025	279	11,897	10.58	2,949
2026	279	12,176	9.52	2,654
2027	279	12,455	8.57	2,389
2028	279	12,734	7.71	2,150
2029	279	13,013	6.94	1,935
2030	279	13,292	6.25	1,742
2031	279	13,570	5.62	1,567
2032	279	13,849	5.06	1,411
2033	279	14,128	4.55	1,270
2034	279	14,407	4.10	1,143
2035	279	14,686	3.69	1,028

115,054

DETERMINATION OF NEW RESERVE ADDITIONS
ROCKY MOUNTAIN AREA
Colorado, Utah and Wyoming
DEVELOPMENT

Year	Wells Drilled	Cumulative Wells	Effectiveness	Reserve Additions	Bcf
1990	991	991	0.15	150	
1991	1,079	2,070	0.65	701	
1992	1,587	3,657	0.40	632	
1993	2,119	5,775	0.44	927	
1994	1,736	7,514	0.26	459	
1995	1,004	8,518	2.09	2,101	
1996	825	9,343	1.30	1,074	
1997	1,489	10,833	0.14	215	
1998	1,944	12,777	0.87	1,699	
1999	2,984	15,761	0.87	2,807	
2000	5,732	21,493	0.37	2,118	
2001	6,982	28,475	0.13	940	
2002	4,554	33,029	0.20	918	
2003	4,252	37,280	0.24	1,017	
2004	5,454	42,734	(0.22)	(1,198)	
2005	7,731	50,465	0.12	952	
2006	7,731	58,195	0.14	1,093	
2007	7,731	65,926	0.14	1,093	
2008	7,731	73,657	0.14	1,093	
2009	7,731	81,388	0.14	1,093	
2010	7,731	89,118	0.14	1,093	
2011	7,731	96,849	0.14	1,093	
2012	7,731	104,580	0.14	1,093	
2013	7,731	112,311	0.14	1,093	
2014	7,731	120,041	0.14	1,093	
2015	7,731	127,772	0.14	1,093	
2016	7,731	135,503	0.14	1,093	
2017	7,731	143,234	0.14	1,093	
2018	7,731	150,964	0.14	1,093	
2019	7,731	158,695	0.14	1,093	
2020	7,731	166,426	0.14	1,093	
2021	7,731	174,157	0.13	884	
2022	7,731	181,887	0.11	885	
2023	7,731	189,618	0.10	797	
2024	7,731	197,349	0.09	717	
2025	7,731	205,080	0.08	645	
2026	7,731	212,810	0.08	581	
2027	7,731	220,541	0.07	523	
2028	7,731	228,272	0.06	471	
2029	7,731	236,003	0.05	424	
2030	7,731	243,733	0.05	381	
2031	7,731	251,464	0.04	343	
2032	7,731	259,195	0.04	309	
2033	7,731	266,926	0.04	278	
2034	7,731	274,656	0.03	250	
2035	7,731	282,387	0.03	225	
					25,162



PRODUCTIVE CAPACITY ROCKY MOUNTAIN AREA

Colorado, Utah and Wyoming

Year	Productive Availability of 2004 Reserves Bcf/Year	Productive Availability of Future Reserves Bcf/Year	Productive Availability	
			Total	Total
			Bcf/Year	Bcf / Day
2006	2,802	1,659	4,461	12.222
2007	2,597	2,480	5,076	13.908
2008	2,407	3,130	5,537	15.169
2009	2,235	3,656	5,891	16.140
2010	2,075	4,097	6,172	16.910
2011	1,926	4,450	6,376	17.468
2012	1,789	4,742	6,530	17.891
2013	1,661	4,996	6,657	18.238
2014	1,542	5,215	6,757	18.512
2015	1,431	5,386	6,818	18.679
2016	1,329	5,536	6,865	18.809
2017	1,234	5,668	6,902	18.910
2018	1,146	5,777	6,923	18.967
2019	1,064	5,864	6,928	18.981
2020	988	5,935	6,923	18.966
2021	917	5,928	6,845	18.755
2022	852	5,806	6,658	18.240
2023	791	5,614	6,405	17.547
2024	734	5,376	6,110	16.739
2025	682	5,081	5,763	15.790
2026	633	4,772	5,405	14.809
2027	588	4,459	5,047	13.826
2028	546	4,148	4,694	12.859
2029	507	3,843	4,349	11.916
2030	471	3,546	4,016	11.004
2031	437	3,262	3,699	10.134
2032	406	2,992	3,397	9.308
2033	377	2,735	3,112	8.525
2034	350	2,493	2,843	7.789
2035	325	2,140	2,465	6.754

ULTIMATE REMAINING GAS RESOURCES

Volumes in Trillion Cubic Feet

Rocky Mountain

Area

Colo, Utah and Wyo

1	Cumulative Production to 12/31/1988	23.96
2	Incremental Production 1989 to 12/31/2004	27.961
3	Remaining Proved Reserves at 12/31/2004	38.55
4	Potential Gas Resources Estimated at 12/31/2004 Wet	114.86
	Potential Gas Resources Estimated at 12/31/2004 Dry Marketable	111.41
5	Ultimate Estimated Resources (12/31/2004)	201.89
6	Gas Discoveries to 12/31/2004	90.47
7	Percent Remaining to be Discovered	55.19

**Estimate of Potential Gas Resources
Rocky Mountain Area
As of End of 2004
Volumes in Bcf**

Producing Province	Resource Estimate						Total Resource Estimate
	Growth in Reserves			New Fields			
	0-15,000 Feet	15,000-30,000 Ft	CBM	0-15,000 Feet	15,000-30,000 Ft	CBM	
Powder River Basin	1,435	-	6,672	2,153	-	20,015	30,275
Big Horn Basin	657	170	-	515	616	25	1,983
Wind River Basin	3,457	1,527	-	6,180	3,401	50	14,615
Greater Green River Basin	10,124	822	-	8,701	1,172	375	21,194
Denver Basin and Environs	1,479	-	-	1,070	-	-	2,549
Uinal/Piceance Basin and Environs	19,222	-	133	17,982	989	4,115	42,441
Thrust Belt	800	-	-	1,000	-	-	1,800
Total Colorado, Utah and Wyoming	37,174	2,519	6,805	37,601	6,178	24,580	114,857
San Juan Basin	5,336	0	7677	11238	0	2559	26,810

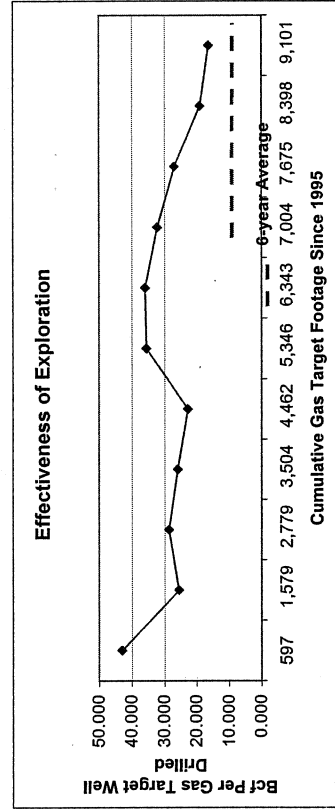
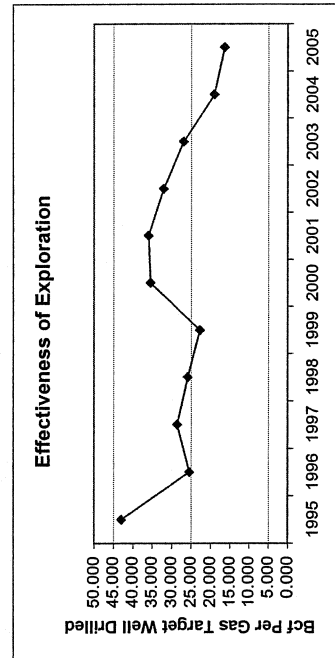
Source: Potential Gas Committee

Note: CBM - Coalbed Methane

Success Ratio and Finding Rate
Exploratory Wells
Offshore Gulf of Mexico Outer Continental Shelf
Texas, Louisiana, Mississippi and Alabama

Year	Wells Drilled			Success Ratio	Gas Target Wells	Gas Target Footage 1,000 Ft	Gas Target Wells as a % of Total	Discoveries		Effectiveness	Cumulative Exploratory Wells	Cumulative Exploratory Footage
	Oil	Gas	Dry					Total Bcf	Per Gas Compl. Bcf/Well	Per Gas Target Well		
1995	2	6	129	0.058	103	597	75.00	4,409	734.83	42,910	103	597
1996	0	19	141	0.119	160	982	100.00	4,069	214.16	25,431	263	1,579
1997	1	21	170	0.115	183	1,200	95.45	5,235	249.29	28,564	446	2,779
1998	1	4	134	0.036	111	725	80.00	2,871	717.75	25,818	557	3,504
1999	0	12	133	0.083	145	958	100.00	3,289	274.08	22,883	702	4,462
2000	3	16	136	0.123	131	885	84.21	4,627	289.19	35,449	833	5,346
2001	2	19	145	0.127	150	997	90.48	5,392	283.79	35,901	983	6,343
2002	2	15	89	0.160	94	660	88.24	3,000	200.00	32,075	1,076	7,004
2003	1	16	90	0.159	101	671	94.12	2,708	169.25	26,890	1,177	7,675
2004	2	27	86	0.252	107	723	93.10	2,034	75.33	18,997	1,284	8,398
2005	5	30	95	0.269	111	702	85.71	1,820	60.67	16,333	1,396	9,101
					116	773				27,608		

6 - Year Average



**Success Ratio and Finding Rate
Development Wells**
Offshore Gulf of Mexico Outer Continental Shelf
Texas, Louisiana, Mississippi and Alabama

Year	Wells Drilled		Success Ratio	Gas Target Wells	Gas Target Footage	Gas Target Wells as a % of Total	Net Additions to Reserves		Per Gas Target Well	Effectiveness Per Gas Target Footage	Cumulative Exploratory Wells	Cumulative Exploratory Footage
	Oil	Gas					Total Bcf	Per Gas Compl. Bcf/Well				
1990							1455					
1991							529					
1992							1011					
1993							1127					
1994							1020					
1995	88	213	0.886	311	1,875	70.76	457	2.15	1.471	0.244	311	1,875
1996	105	257	0.727	354	2,176	70.99	606	2.36	1.714	0.279	664	4,050
1997	116	281	0.669	420	2,543	70.78	289	1.03	0.689	0.114	1,084	6,593
1998	54	234	0.600	390	2,364	81.25	(172)	-0.74	-0.441	-0.073	1,474	8,967
1999	61	177	0.631	280	1,476	74.37	915	5.17	3.263	0.620	1,754	10,433
2000	71	241	0.693	348	1,737	77.24	547	2.27	1.574	0.315	2,102	12,170
2001	82	268	0.790	339	1,717	76.57	(168)	-0.63	-0.495	-0.098	2,441	13,888
2002	55	150	0.788	190	1,036	73.17	(546)	-3.64	-2.870	-0.527	2,631	14,924
2003	74	181	0.847	214	1,252	70.98	(1,182)	-6.53	-5.532	-0.944	2,845	16,176
2004	56	195	0.730	267	1,603	77.69	(1,463)	-7.50	-5.474	-0.913	3,112	17,779
2005	47	154	0.882	175	1,067	76.62	(632)	-4.10	-3.618	-0.592	3,287	18,846
				255	1,402		237		-0.884	-0.143		
				Most Recent 6 - Year Average			16 - Year Average		11 - Year Average			

**DETERMINATION OF NEW RESERVE ADDITIONS
TOTAL GULF OF MEXICO AREA**

Volumes in Bcf

Year	New Exploratory Additions	New Development Additions	New Total Additions	Accumulated Ultimate Reserves	Percent of Ultimate Resources	Cumulative Prod to 12/31/2000	142,469
						Gas Production 2001-2004	18,285
						Remaining Reserves at 12/31/2004	19,515
2000	4,627	547	5,174	167,135	71.1	Ultimate Reserves at 12/31/2004	180,269
2001	5,392	(168)	5,392	172,527	73.4	PGC Potential Wet 12/31/2004	54,759
2002	3,000	(546)	3,000	175,527	74.7	PGC Potential Dry Marketable	52,569
2003	2,708	(1,182)	2,708	178,235	75.8	Ultimate Resources at 12/31/2004	235,028
2004	2,034	(1,463)	2,034	180,269	76.7		
2005	1,820	237	2,057	182,326	77.6		
2006	3,270	237	3,507	185,834	79.1		
2007	3,270	237	3,507	189,341	80.6		
2008	3,270	237	3,507	192,848	82.1		
2009	3,270	237	3,507	196,356	83.5		
2010	3,270	237	3,507	199,863	85.0		
2011	3,270	237	3,507	203,371	86.5		
2012	3,270	237	3,507	206,878	88.0		
2013	3,270	237	3,507	210,386	89.5		
2014	2,943	213	3,157	213,542	90.9		
2015	2,649	192	2,841	216,383	92.1		
2016	2,384	173	2,557	218,940	93.2		
2017	2,146	156	2,301	221,242	94.1		
2018	1,931	140	2,071	223,313	95.0		
2019	1,738	126	1,864	225,177	95.8		
2020	1,564	113	1,678	226,854	96.5		
2021	1,408	102	1,510	228,364	97.2		
2022	1,267	92	1,359	229,723	97.7		
2023	1,140	83	1,223	230,946	98.3		
2024	1,026	74	1,101	232,047	98.7		
2025	924	67	991	233,037	99.2		
2026	831	60	892	233,929	99.5		
2027	748	54	802	234,731	99.9		
2028	673	49	722	235,453	100.2		
2029	606	44	650	236,103	100.5		
2030	545	40	585	236,688	100.7		
2031	491	36	526	237,215	100.9		
2032	442	32	474	237,689	101.1		
2033	398	29	426	238,115	101.3		
2034	358	26	384	238,499	101.5		
2035	322	23	345	238,844	101.6		

Production Availability of Gas in the Gulf of Mexico

Volumes in Bcf

Year	Production Availability Existing Proven Reserves	Production Availability Future Resources	Production Availability Reserves and Resources	Historical Production
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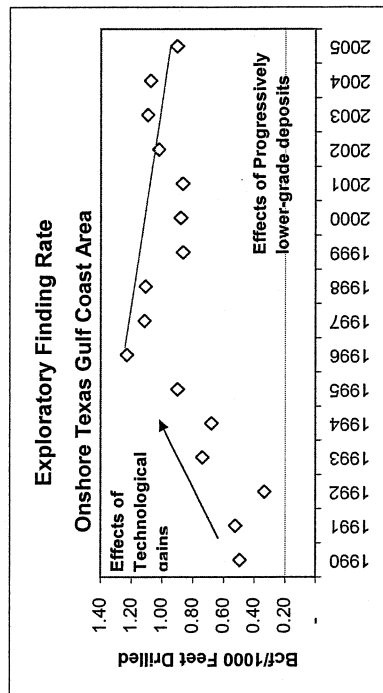
Year	Production Availability Existing Proven Reserves	Production Availability Future Resources	Production Availability Reserves and Resources	Total Availability Bcf Per Day	Actual Historical Production
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				Actual Production	
2000				-	13.6
2001				-	14.1
2002				-	12.6
2003				-	12.3
2004				-	11.1
2005	5,643	453	6,096	16.7	
2006	4,460	1,070	5,530	15.1	
2007	2,867	1,410	4,277	11.7	
2008	1,866	1,773	3,638	10.0	
2009	1,092	2,171	3,263	8.9	
2010	774	2,521	3,295	9.0	
2011	455	2,768	3,223	8.8	
2012	341	2,937	3,278	9.0	
2013	228	3,066	3,294	9.0	
2014	182	3,159	3,341	9.2	
2015	159	3,194	3,354	9.2	
2016	141	3,162	3,303	9.0	
2017	127	3,070	3,198	8.8	
2018	114	2,924	3,038	8.3	
2019	103	2,751	2,854	7.8	
2020	95	2,566	2,660	7.3	
2021	88	2,378	2,466	6.8	
2022	81	2,195	2,276	6.2	
2023	76	2,017	2,094	5.7	
2024	72	1,850	1,922	5.3	
2025	68	1,687	1,754	4.8	
2026	64	1,536	1,600	4.4	
2027	61	1,397	1,458	4.0	
2028	58	1,268	1,326	3.6	
2029	55	1,149	1,204	3.3	
2030	53	1,039	1,092	3.0	
2031	51	939	990	2.7	
2032	49	848	897	2.5	
2033	47	765	812	2.2	
2034	45	689	734	2.0	
2035	44	557	601	1.6	
	19,559	59,309	78,868		

Success Ratio and Finding Rate Exploratory Wells

Onshore Texas Gulf Coast

Year	Wells Drilled		Success Ratio	Gas Target Wells	Gas Target Wells as a % of Total	Gas Target Footage 1,000 Ft.	Discoveries		Finding Rate		Cumulative Gas Target Footage 1,000 Feet	Finding Rate Per Foot Drilled	Annual Gas Target Footage 1,000 Feet
	Oil	Gas					Total Bcf	Per Gas Compl. Bcf/Well	Per Well	Per Foot Drilled 1,000 Feet			
1990	28	169	0.411	411	85.79	2571	1,272	7.53	3.096	0.49	2,571	0.49	2570.95
1991	19	120	0.376	319	86.33	1980	1,038	8.65	3.250	0.52	4,551	0.52	1979.97
1992	17	101	0.384	263	85.59	1546	514	5.09	1.956	0.33	6,096	0.33	1545.55
1993	27	141	0.453	311	83.93	1848	1,362	9.66	4.374	0.74	7,944	0.74	1847.50
1994	42	242	0.512	473	85.21	2904	1,972	8.15	4.170	0.68	10,848	0.68	2903.78
1995	26	122	0.376	325	82.43	1961	1,754	14.38	5.401	0.89	12,808	0.89	1960.72
1996	24	131	0.405	324	84.52	2017	2,482	18.95	7.668	1.23	14,826	1.23	2017.26
1997	22	152	0.423	359	87.36	2436	2,714	17.86	7.559	1.11	17,262	1.11	2436.45
1998	25	167	0.459	364	86.98	2530	2,803	16.78	7.710	1.11	19,793	1.11	2530.37
1999	17	117	0.395	296	87.31	1878	1,619	13.84	5.470	0.86	21,671	0.86	1878.17
2000	14	193	0.520	371	93.24	2625	2,300	11.92	6.198	0.88	24,296	0.88	2625.02
2001	11	148	0.317	467	93.08	3148	2,723	18.40	5.827	0.86	27,444	0.86	3147.99
2002	11	92	0.312	295	89.32	2052	2,093	22.75	7.101	1.02	29,496	1.02	2052.34
2003	29	129	0.421	306	81.65	2000	2,186	16.95	7.140	1.09	31,496	1.09	2000.26
2004	18	123	0.417	295	87.23	1879	2,018	16.41	6.844	1.07	33,375	1.07	1878.53
2005	14	125	0.355	353	89.93	2275	2,044	16.35	5.798	0.90	35,650	0.90	2275.08
				348		2,330	2,227		6.485	0.971			
				6-Year Avg		6-Year Avg	6-Year Avg		6-Year Avg	6-Year Avg			



Success Ratio and Finding Rate Development Wells

Onshore Texas Gulf Coast

Year	Wells Drilled			Success Ratio	Gas Target Wells	Gas Target Wells as a % of Total	Gas Target Footage 1,000 Ft.	Discoveries		Finding Rate		Cumulative Gas Target Footage 1,000 Feet	Finding Rate Per Foot Drilled	Annual Gas Target Footage 1,000 Feet
	Oil	Gas	Dry					Total Bcf	Per Gas Compl. Bcf/Well	Per Well	Per Foot Drilled 1,000 Feet			
1990	326	555	415	1,296	0.680	816	63.00	4,105	0.72	0.491	0.10	4,105	0.10	4,104.88
1991	535	502	380	1,417	0.732	686	48.41	3,536	0.57	0.420	0.08	7,641	0.08	3536.20
1992	526	544	368	1,438	0.744	731	50.84	4,025	0.13	0.097	0.02	11,666	0.02	4025.40
1993	432	781	370	1,583	0.766	1,019	64.39	5,935	0.63	0.483	0.08	17,601	0.08	5934.55
1994	326	820	340	1,486	0.771	1,063	71.55	6,506	1.05	0.813	0.13	24,107	0.13	6505.55
1995	215	756	311	1,282	0.757	998	77.86	6,104	1.48	1.123	0.18	30,210	0.18	6103.60
1996	210	854	350	1,414	0.752	1,135	80.26	6,883	-0.08	-0.062	(0.01)	37,093	(0.01)	6883.30
1997	244	1,031	406	1,681	0.758	1,359	80.86	8,270	0.29	0.216	0.04	45,363	0.04	8269.96
1998	135	1,269	320	1,724	0.814	1,558	90.38	9,633	0.25	0.205	0.03	54,996	0.03	9632.90
1999	158	977	283	1,418	0.800	1,221	86.08	6,629	0.95	0.757	0.14	61,625	0.14	6628.60
2000	196	1,146	359	1,701	0.789	1,453	85.39	7,148	0.04	0.030	0.01	68,773	0.01	7147.78
2001	190	1,362	202	1,754	0.885	1,539	87.76	7,768	-0.42	-0.376	(0.07)	76,541	(0.07)	7767.95
2002	172	1,075	219	1,466	0.851	1,264	86.21	6,812	-0.53	-0.449	(0.08)	83,353	(0.08)	6812.39
2003	225	1,334	271	1,830	0.852	1,566	85.57	8,919	-0.95	-0.810	(0.14)	92,272	(0.14)	8918.79
2004	227	1,335	372	1,934	0.808	1,653	85.47	9,740	-0.41	-0.333	(0.06)	102,012	(0.06)	9739.93
2005	273	1,841	423	2,537	0.833	2,209	87.09	13,396	-0.07	-0.057	(0.01)	115,408	(0.01)	13396.36
						1,614	8,964	104		0.159	0.027			
					6-Year Avg	6-Year Avg	6-Year Avg	16-Year Avg		16-Year Avg	16-Year Avg			

**DETERMINATION OF DECLINE IN FINDING RATE
ONSHORE TEXAS GULF COAST**

Year	New Expl Additions	New Development Additions	Total New Additions	Accumulated Ultimate Reserves	Percent of Ultimate Resources	Cumulative Prod to 12/31/2000 155.027
						Prod 2001 through 2004
						Remaining Reserves at 12/31/2004 15.498
						Ultimate Reserves at 12/31/2004 170.525
2000	1,747	883	2,630	164,470	80.0	
2001	2,723	(578)	2,145	166,615	81.1	PGC Potential (est. at 12/31/2004) 36.406
						PGC Potential, Adjusted to Dry Gas 34.950
2002	2,093	(567)	1,526	168,141	81.8	
2003	2,186	(1,269)	917	169,058	82.3	Ultimate Resources at 12/31/2004 205.475
2004	2,018	(551)	1,467	170,525	83.0	
2005	2,044	950	2,994	173,519	84.4	
2006	2,263	950	3,213	176,732	86.0	
2007	2,263	950	3,213	179,944	87.6	
2008	2,263	950	3,213	183,157	89.1	
2009	2,263	950	3,213	186,369	90.7	
2010	2,263	950	3,213	189,582	92.3	
2011	2,036	855	2,891	192,473	93.7	
2012	1,833	770	2,602	195,075	94.9	
2013	1,649	693	2,342	197,417	96.1	
2014	1,484	623	2,108	199,525	97.1	
2015	1,336	561	1,897	201,422	98.0	
2016	1,202	505	1,707	203,129	98.9	
2017	1,082	454	1,537	204,665	99.6	
2018	974	409	1,383	206,048	100.3	
2019	877	368	1,245	207,293	100.9	
2020	789	331	1,120	208,413	101.4	
2021	710	298	1,008	209,421	101.9	
2022	639	268	907	210,328	102.4	
2023	575	241	817	211,145	102.8	
2024	518	217	735	211,880	103.1	
2025	466	196	661	212,541	103.4	
2026	419	176	595	213,137	103.7	
2027	377	158	536	213,672	104.0	
2028	340	143	482	214,154	104.2	
2029	306	128	434	214,588	104.4	
2030	275	115	391	214,979	104.6	
2031	248	104	352	215,331	104.8	
2032	223	94	316	215,647	105.0	
2033	201	84	285	215,932	105.1	
2034	180	76	256	216,188	105.2	
2035	162	68	231	216,418	105.3	
	32,095	13,568	45,663			

Area-wide Gas Production Availability Onshore Texas Gulf Coast

Year	<i>Volumes in Bcf</i>		Total Gas Production Availability
	Availability of Gas From Proven Reserves	Availability of Gas From Future Discoveries	
2006	6.46	4.30	10.76
2007	4.50	5.80	10.30
2008	3.16	6.76	9.92
2009	2.48	7.39	9.87
2010	1.89	7.79	9.68
2011	1.50	7.89	9.39
2012	1.17	7.66	8.83
2013	1.04	7.27	8.32
2014	0.91	6.80	7.71
2015	0.78	6.30	7.08
2016	0.72	5.80	6.52
2017	0.65	5.31	5.96
2018	0.59	4.85	5.44
2019	0.52	4.42	4.94
2020	0.46	4.02	4.47
2021	0.39	3.65	4.04
2022	0.33	3.31	3.63
2023	0.26	3.00	3.26
2024	0.23	2.71	2.94
2025	0.20	2.45	2.65
2026	0.17	2.21	2.38
2027	0.15	1.99	2.14
2028	0.13	1.79	1.92
2029	0.11	1.61	1.72
2030	0.09	1.45	1.55
2031	0.08	1.31	1.39
2032	0.07	1.18	1.25
2033	0.06	1.06	1.12
2034	0.05	0.95	1.00
2035	0.04	0.72	0.75

**DETERMINATION OF DECLINE IN FINDING RATE
ONSHORE LOUISIANA**

Year	New Expl Additions	New Development Additions	New Total Additions	Accumulated Ultimate Reserves	Percent of Ultimate Resources	Cumulative Prod to 12/31/2000	136,160
						Production 2001-2004	4,914
						Remaining Reserves at 12/31/2004	9,206
						Ultimate Reserves at 12/31/2004	150,280
2000	1,747	388	2,135	150,280	85.9	PGC Potential (est. at 12/31/2004	25,600
2001	2,020	(667)	1,353	151,633	86.7	PGC Potential Dry - Marketable	24,576
2002	970	(426)	544	152,177	87.0	Ultimate Resources at 12/31/2004	174,856
2003	1,840	(367)	1,473	153,650	87.9		
2004	2,079	(121)	1,958	155,608	89.0		
2005	1,754	1,000	2,754	158,362	90.6		
2006	1,808	1,000	2,808	161,170	92.2		
2007	1,628	900	2,528	163,698	93.6		
2008	1,465	810	2,275	165,973	94.9		
2009	1,318	729	2,047	168,020	96.1		
2010	1,186	656	1,843	169,863	97.1		
2011	1,068	590	1,658	171,521	98.1		
2012	961	531	1,492	173,013	98.9		
2013	865	478	1,343	174,357	99.7		
2014	778	430	1,209	175,566	100.4		
2015	701	387	1,088	176,654	101.0		
2016	631	349	979	177,633	101.6		
2017	567	314	881	178,514	102.1		
2018	511	282	793	179,307	102.5		
2019	460	254	714	180,021	103.0		
2020	414	229	642	180,664	103.3		
2021	372	206	578	181,242	103.7		
2022	335	185	520	181,762	103.9		
2023	302	167	468	182,231	104.2		
2024	271	150	422	182,652	104.5		
2025	244	135	379	183,032	104.7		
2026	220	122	341	183,373	104.9		
2027	198	109	307	183,680	105.0		
2028	178	98	277	183,957	105.2		
2029	160	89	249	184,206	105.3		
2030	144	80	224	184,430	105.5		
2031	130	72	202	184,631	105.6		
2032	117	65	181	184,813	105.7		
2033	105	58	163	184,976	105.8		
2034	95	52	147	185,123	105.9		
2035	85	47	132	185,255	105.9		
	19,071	10,576	29,647				

Area-wide Gas Production Availability Onshore Louisiana

Year	<i>Volumes in Bcf per Day</i>		
	Availability of Gas From Proven Reserves	Availability of Gas From Future Discoveries	Total Gas Production Availability
2006	4.33	1.80	6.13
2007	3.02	2.70	5.72
2008	2.12	3.36	5.48
2009	1.66	3.76	5.43
2010	1.27	4.04	5.31
2011	1.01	4.17	5.18
2012	0.79	4.21	5.00
2013	0.70	4.18	4.88
2014	0.61	4.08	4.69
2015	0.52	3.93	4.45
2016	0.48	3.76	4.24
2017	0.44	3.56	4.00
2018	0.39	3.35	3.75
2019	0.35	3.14	3.49
2020	0.31	2.93	3.24
2021	0.26	2.72	2.98
2022	0.22	2.52	2.74
2023	0.17	2.32	2.49
2024	0.15	2.13	2.28
2025	0.13	1.95	2.08
2026	0.11	1.79	1.90
2027	0.10	1.63	1.73
2028	0.09	1.49	1.58
2029	0.07	1.36	1.44
2030	0.06	1.24	1.31
2031	0.05	1.14	1.19
2032	0.05	1.04	1.08
2033	0.04	0.94	0.98
2034	0.03	0.86	0.89
2035	0.03	0.74	0.77

DETERMINATION OF DECLINE IN FINDING RATE
Permian Basin and Fort Worth Basin

Year	New Expl Additions	New Development Additions	Total New Additions	Accumulated Ultimate Reserves	Percent of Ultimate Resources	Cumulative Prod to 12/31/2004	115.837
						Remaining Reserves at 12/31/2004	51.595
						Ultimate Reserves at 12/31/2004	167.432
2000	2,495	1,365	3,860	155,051	78.1		
2001	3,140	(1,021)	2,119	157,170	79.1	PGC Potential (est. at 12/31/2004)	32.506
2002	2,233	500	2,733	159,903	80.5		
2003	2,708	339	3,047	162,950	82.0	PGC Potential, Adjusted to Dry Gas	31.206
2004	2,949	1,533	4,482	167,432	84.3		
2005	2,705	543	3,248	170,680	85.9	Ultimate Resources at 12/31/2004	198.638
2006	2,705	543	3,248	173,928	87.6		
2007	2,705	543	3,248	177,177	89.2		
2008	2,435	489	2,923	180,100	90.7		
2009	2,191	440	2,631	182,731	92.0		
2010	1,972	396	2,368	185,099	93.2		
2011	1,775	356	2,131	187,230	94.3		
2012	1,597	321	1,918	189,148	95.2		
2013	1,438	289	1,726	190,874	96.1		
2014	1,294	260	1,554	192,428	96.9		
2015	1,164	234	1,398	193,826	97.6		
2016	1,048	210	1,258	195,085	98.2		
2017	943	189	1,133	196,217	98.8		
2018	849	170	1,019	197,237	99.3		
2019	764	153	917	198,154	99.8		
2020	688	138	826	198,980	100.2		
2021	619	124	743	199,723	100.5		
2022	557	112	669	200,391	100.9		
2023	501	101	602	200,993	101.2		
2024	451	91	542	201,535	101.5		
2025	406	82	488	202,023	101.7		
2026	365	73	439	202,461	101.9		
2027	329	66	395	202,856	102.1		
2028	296	59	355	203,212	102.3		
2029	266	53	320	203,532	102.5		
2030	240	48	288	203,819	102.6		
2031	216	43	259	204,079	102.7		
2032	194	39	233	204,312	102.9		
2033	175	35	210	204,522	103.0		
2034	157	32	189	204,710	103.1		
	31,044	6,234	37,278				

**DETERMINATION OF NEW RESERVE ADDITIONS
KANSAS, OKLAHOMA AND TEXAS RRD 10 MID-CONTINENT AREA**

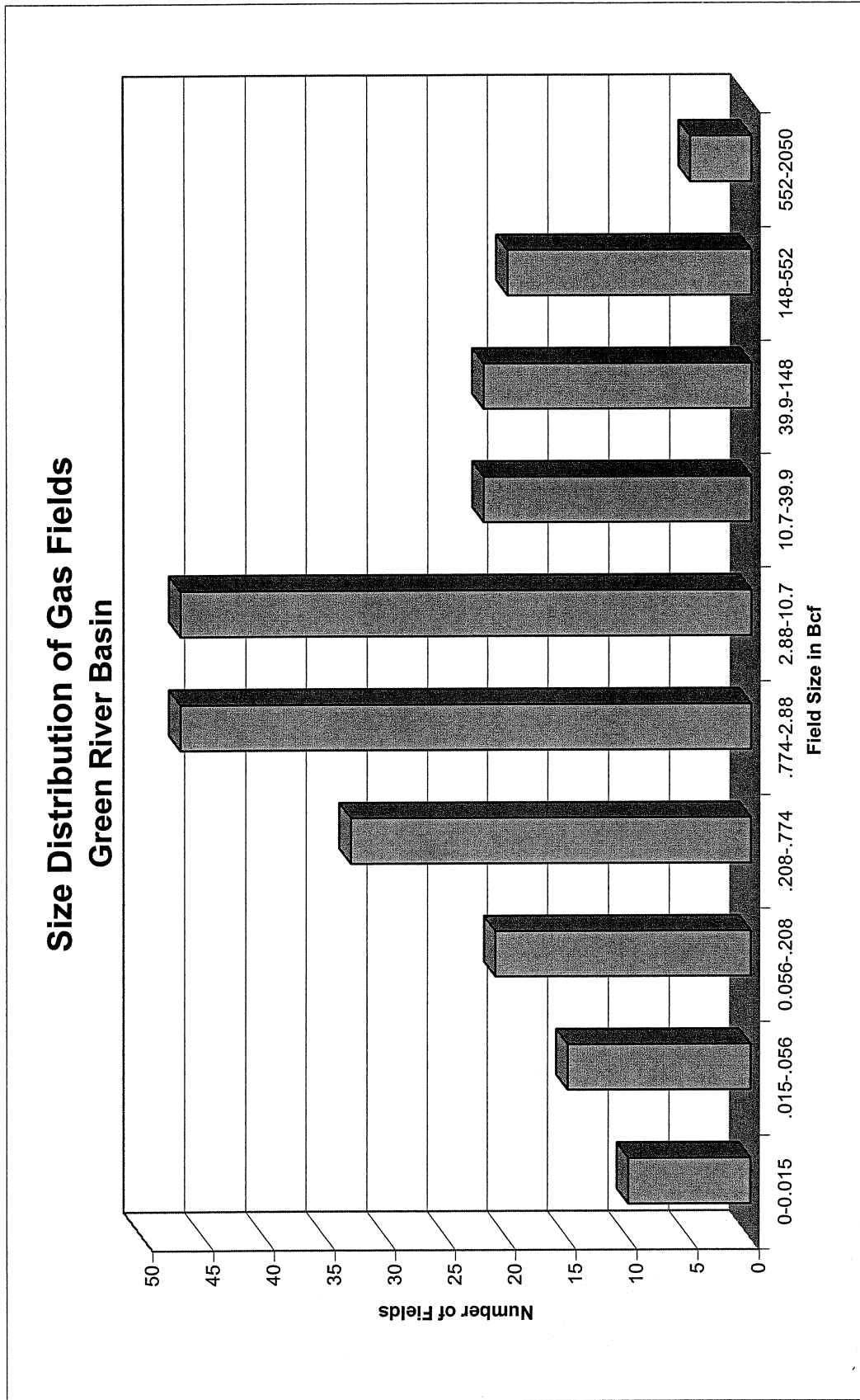
Volumes in Bcf							
Year	New Exploratory	New Development	New Total	Accumulated Ultimate	Percent of Ultimate	Cumulative Prod to 12/31/2000	180,011
	Additions	Additions	Additions	Reserves	Resources	Production 2001-2004	9,250
						Remaining Reserves at 12/31/2004	25,763
1999	902	806	1,708		-	Ultimate Reserves at 12/31/2004	215,024
2000	1,253	1,209	2,462		-		
2001	1,600	(401)	1,199		-	PGC Potential Resources 2004 - Wet	43,812
2002	1,428	835	2,263		-	PGC Potential Resources 2004 - Dry Marketable	42,060
2003	1,933	232	2,165		-		
2004	2,896	466	3,362	215,024	83.6	Ultimate Resources at 12/31/2004	257,084
2005	1,863	1,050	2,913	217,937	84.8		
2006	1,863	1,050	2,913	220,849	85.9		
2007	1,863	1,050	2,913	223,762	87.0		
2008	1,676	1,050	2,726	226,489	88.1		
2009	1,509	1,050	2,559	229,048	89.1		
2010	1,358	1,050	2,408	231,455	90.0		
2011	1,222	945	2,167	233,623	90.9		
2012	1,100	851	1,950	235,573	91.6		
2013	990	765	1,755	237,328	92.3		
2014	891	689	1,580	238,908	92.9		
2015	802	620	1,422	240,330	93.5		
2016	722	558	1,280	241,610	94.0		
2017	649	502	1,152	242,762	94.4		
2018	585	452	1,037	243,798	94.8		
2019	526	407	933	244,731	95.2		
2020	473	366	840	245,571	95.5		
2021	426	330	756	246,326	95.8		
2022	384	297	680	247,006	96.1		
2023	345	267	612	247,618	96.3		
2024	311	240	551	248,169	96.5		
2025	280	216	496	248,665	96.7		
2026	252	195	446	249,111	96.9		
2027	226	175	402	249,513	97.1		
2028	204	158	361	249,874	97.2		
2029	183	142	325	250,199	97.3		
2030	165	128	293	250,492	97.4		
2031	149	115	263	250,756	97.5		
2032	134	103	237	250,993	97.6		
2033	120	93	213	251,206	97.7		
2034	108	84	192	251,398	97.8		
	21,378	14,996	36,374				

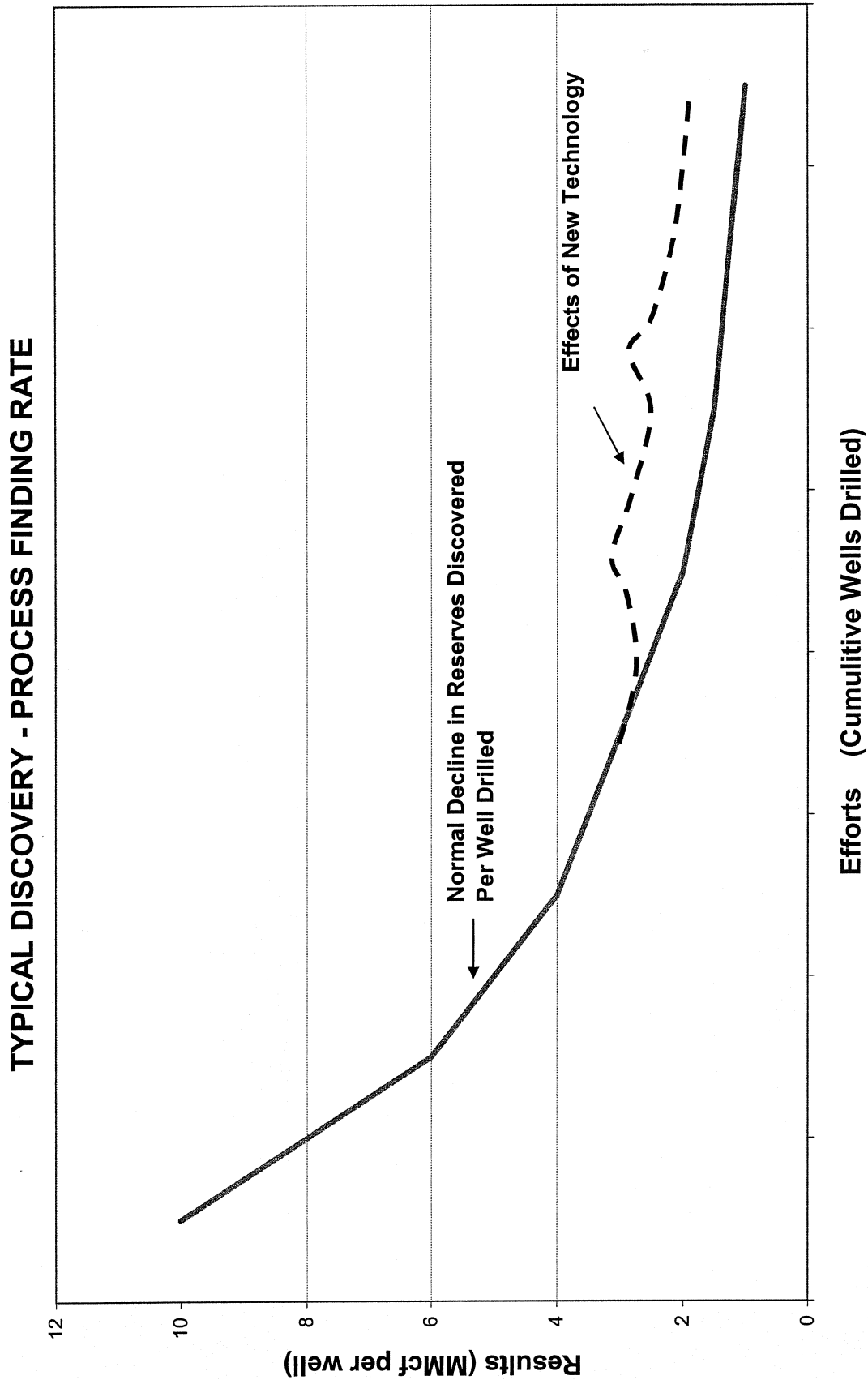
Gas Availability - Total Midcontinent Area **Hugoton - Anadarko Basin, Permian Basin and Fort Worth Basin**

Actual 2004 = 12.96

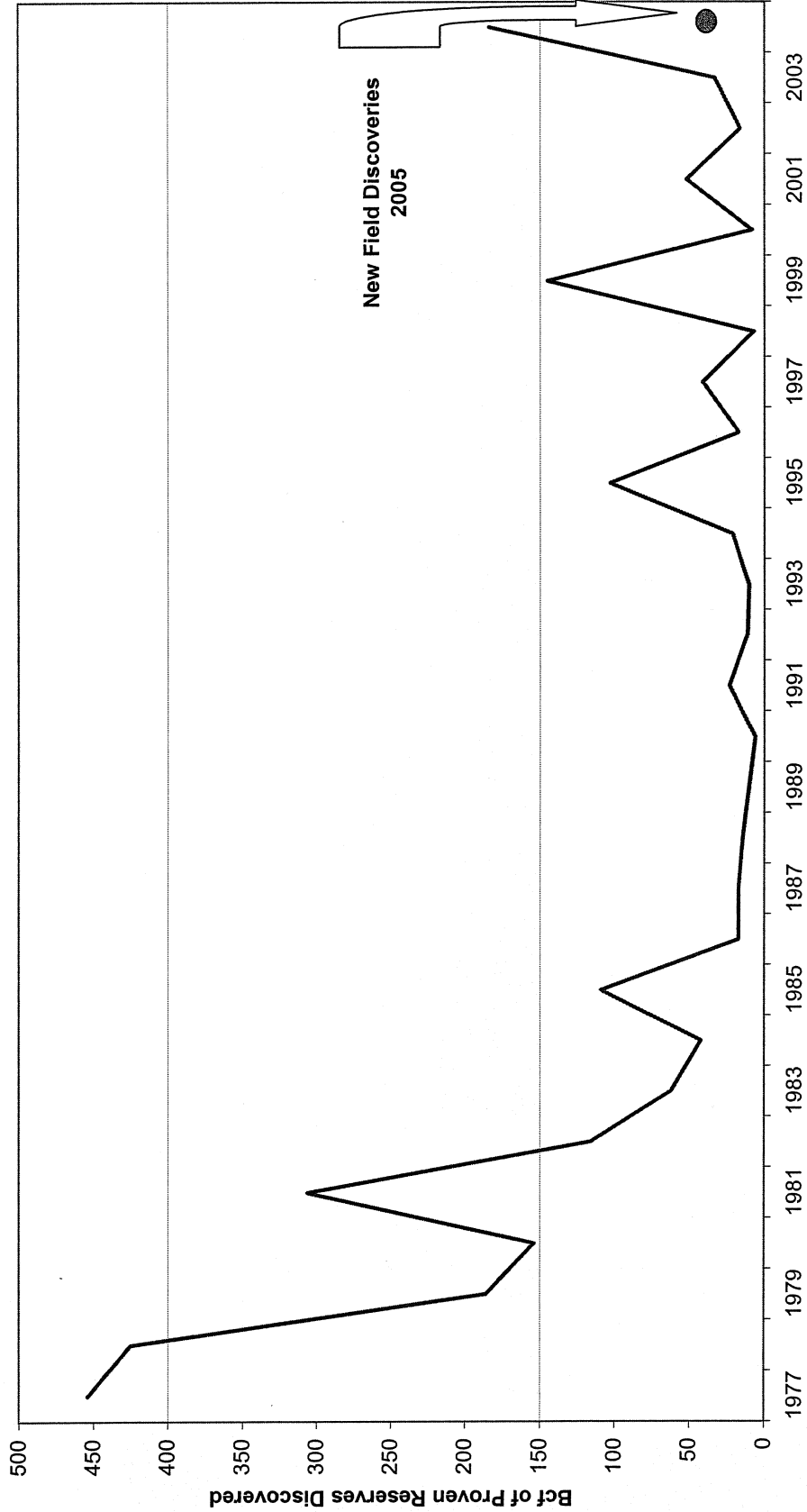
Year	Production of		Availability from Future Reserves		Bcf Per Day	
	Existing Reserves (Bcf per Day)	Hugoton-Anadarko	Permian-Fort Worth	Total (Bcf per Day)	Total Midcontinent	
2005	16.60	498	853	3.70	20.30	
2006	14.63	1,212	1,822	8.31	22.94	
2007	11.68	1,707	2,346	11.10	22.79	
2008	9.28	2,103	2,773	13.36	22.64	
2009	7.86	2,347	2,973	14.58	22.44	
2010	6.77	2,471	3,073	15.19	21.96	
2011	5.79	2,513	3,085	15.34	21.12	
2012	5.24	2,503	3,050	15.21	20.45	
2013	4.70	2,437	2,942	14.74	19.43	
2014	4.04	2,331	2,795	14.04	18.08	
2015	3.60	2,211	2,642	13.30	16.90	
2016	3.28	2,082	2,479	12.50	15.77	
2017	3.01	1,947	2,312	11.67	14.68	
2018	2.73	1,817	2,156	10.88	13.61	
2019	2.51	1,691	2,003	10.12	12.63	
2020	2.83	1,569	1,858	9.39	12.22	
2021	2.70	1,453	1,719	8.69	11.39	
2022	2.59	1,343	1,586	8.02	10.61	
2023	2.48	1,241	1,467	7.42	9.90	
2024	2.39	1,148	1,358	6.87	9.25	
2025	2.30	1,060	1,252	6.33	8.63	
2026	2.22	977	1,154	5.84	8.06	
2027	2.15	900	1,062	5.37	7.52	
2028	2.08	827	975	4.94	7.02	
2029	2.02	758	893	4.52	6.54	
2030	1.96	694	816	4.14	6.09	
2031	1.90	633	743	3.77	5.67	
2032	1.85	575	674	3.42	5.27	
2033	1.80	522	612	3.11	4.91	
2034	1.76	474	555	2.82	4.57	
2035	1.71	400	512	2.50	4.21	

FIGURES TO THE ASSESSMENT OF GAS SUPPLY



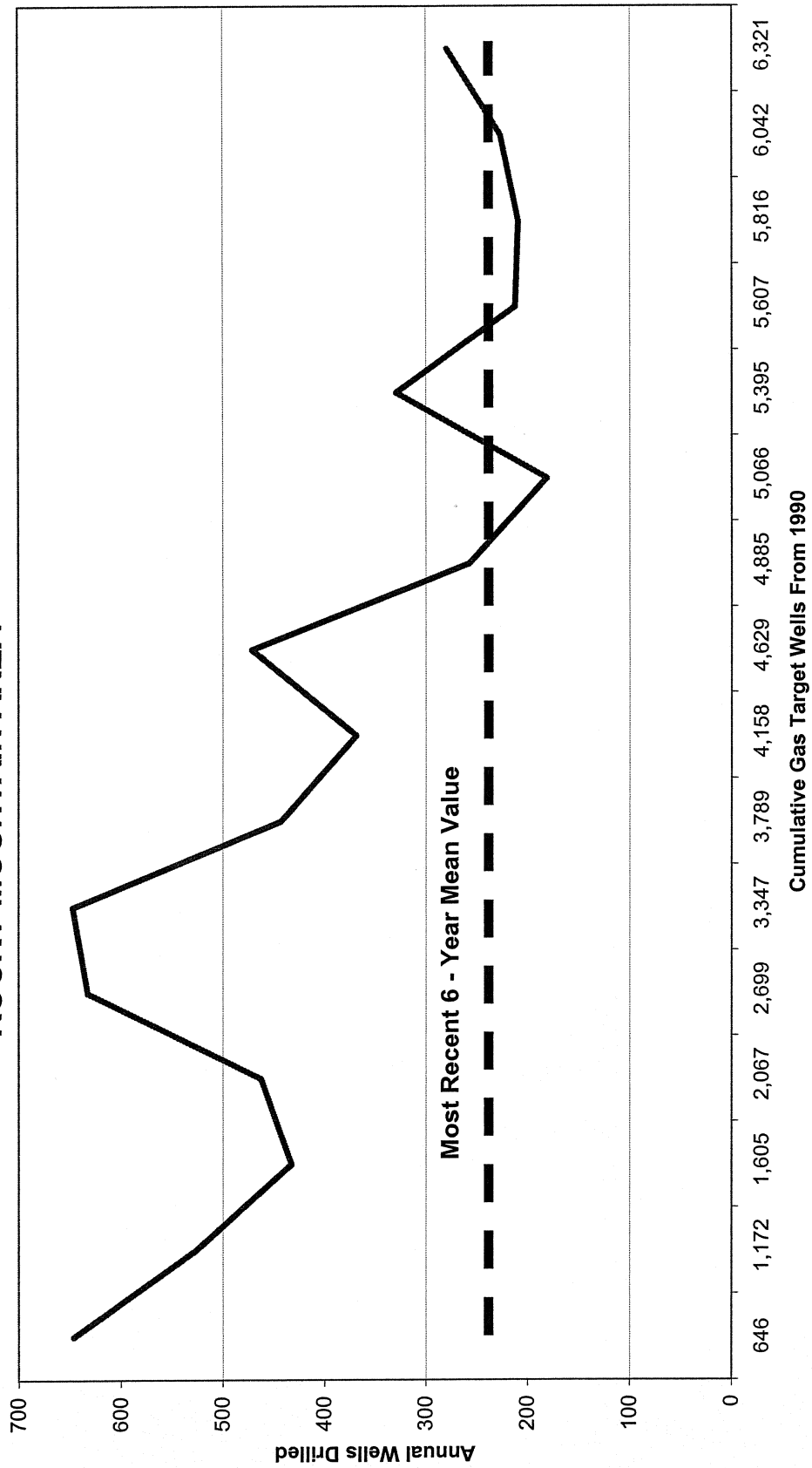


New Field Discoveries Colorado, Utah and Wyoming



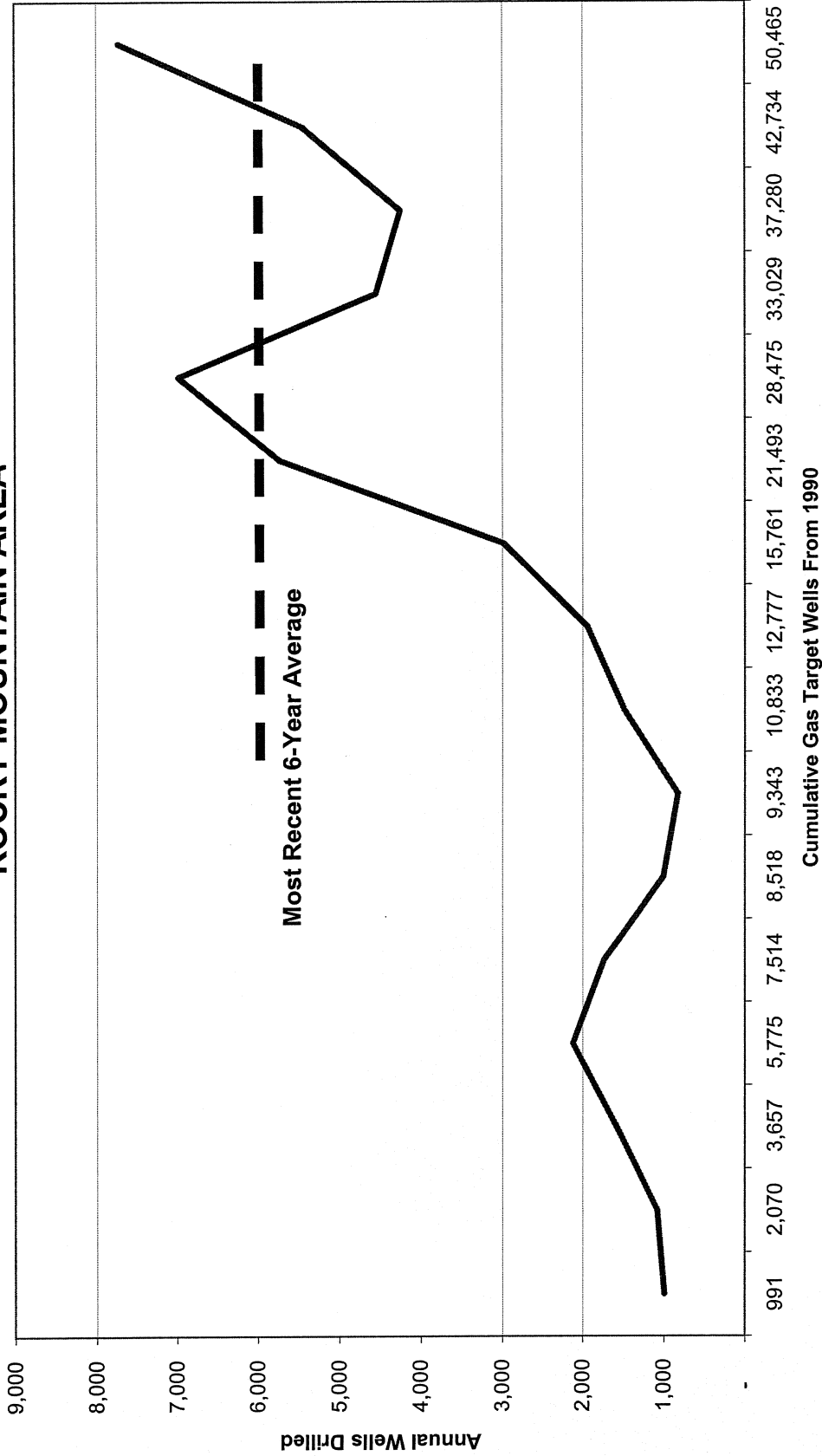
GAS TARGET EXPLORATORY WELLS

ROCKY MOUNTAIN AREA



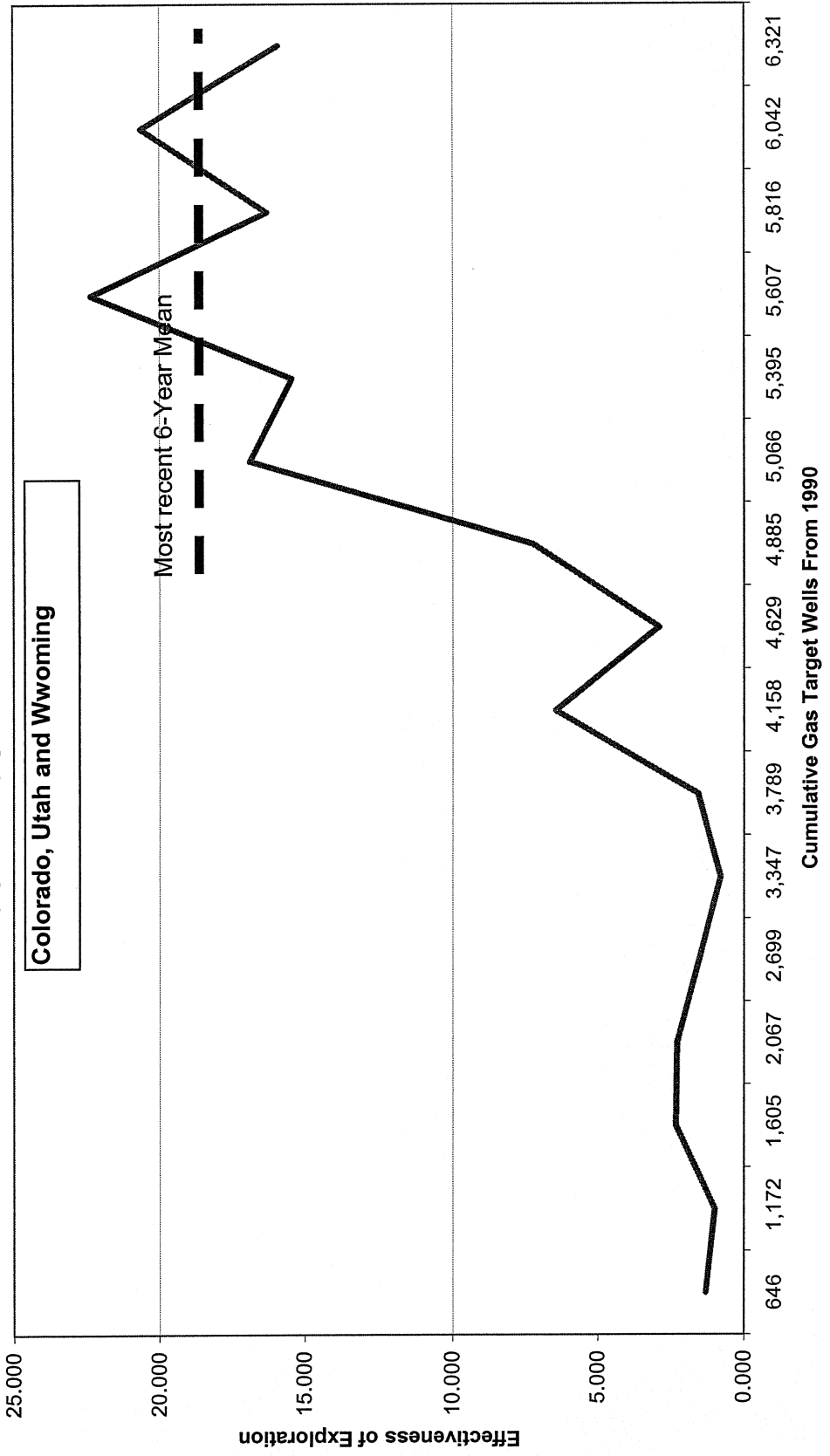
GAS TARGET DEVELOPMENT WELLS

ROCKY MOUNTAIN AREA

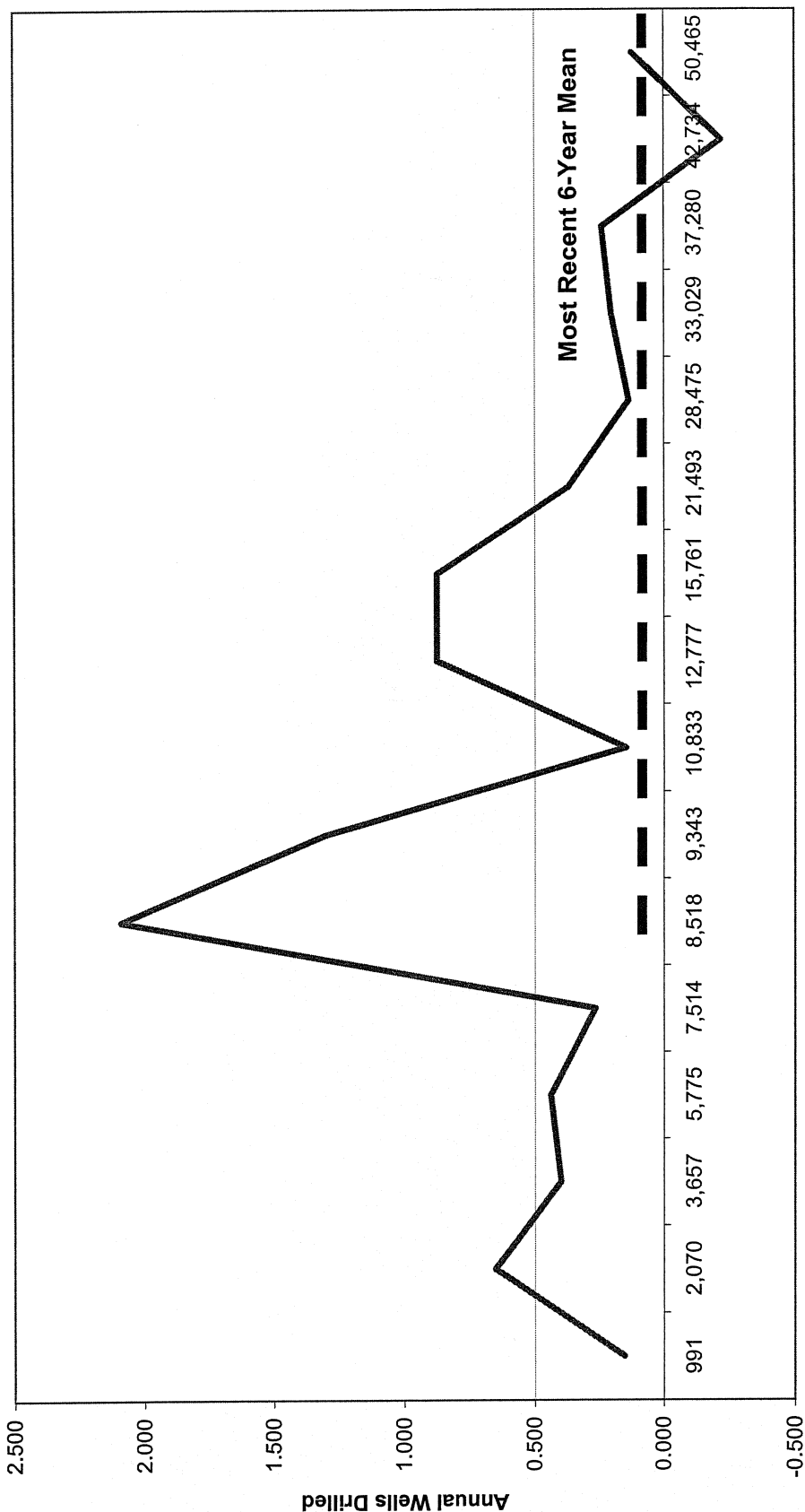


FINDING RATE OF EXPLORATION

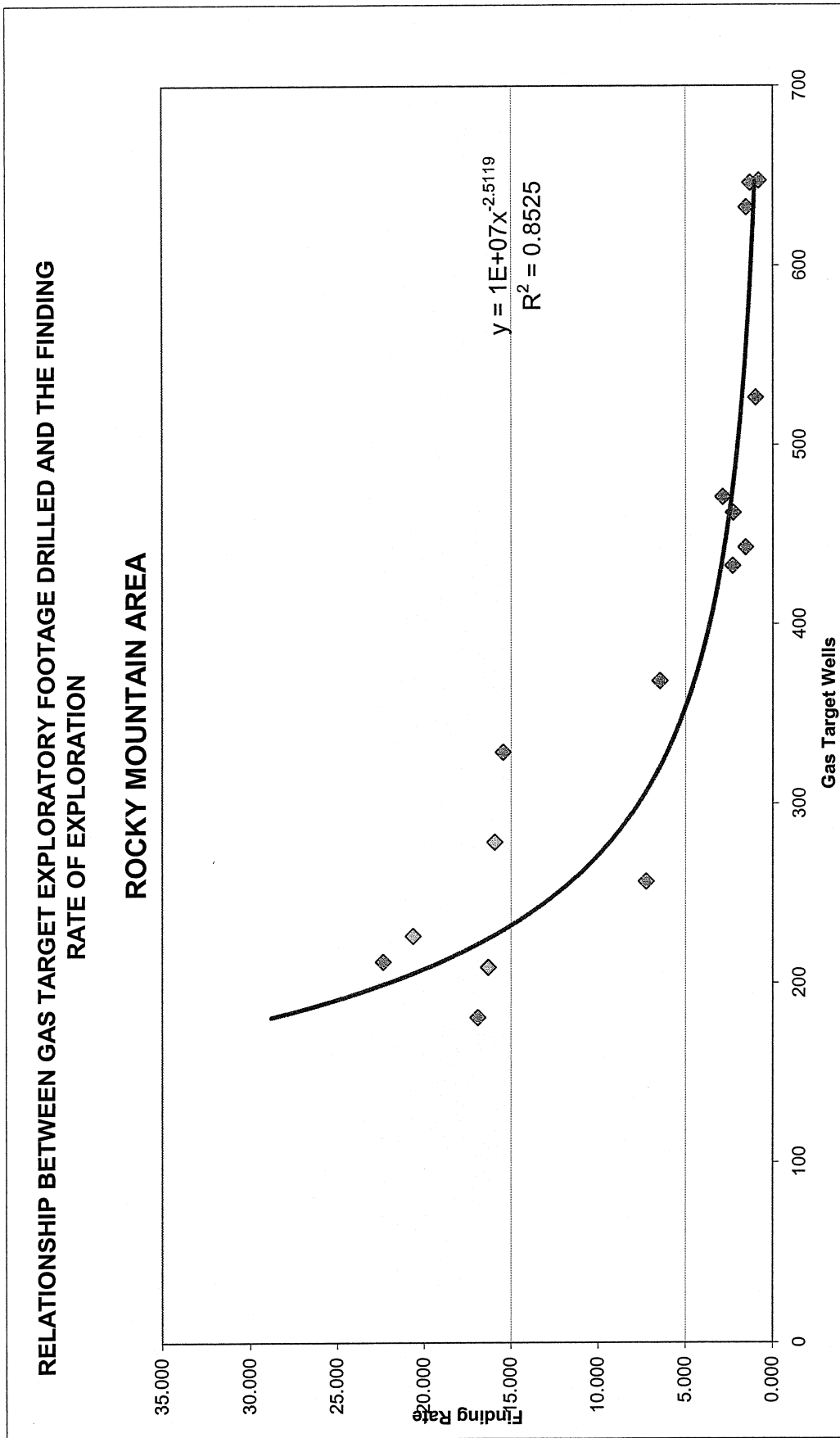
ROCKY MOUNTAIN



FINDING RATE OF DEVELOPMENT ROCKY MOUNTAIN AREA

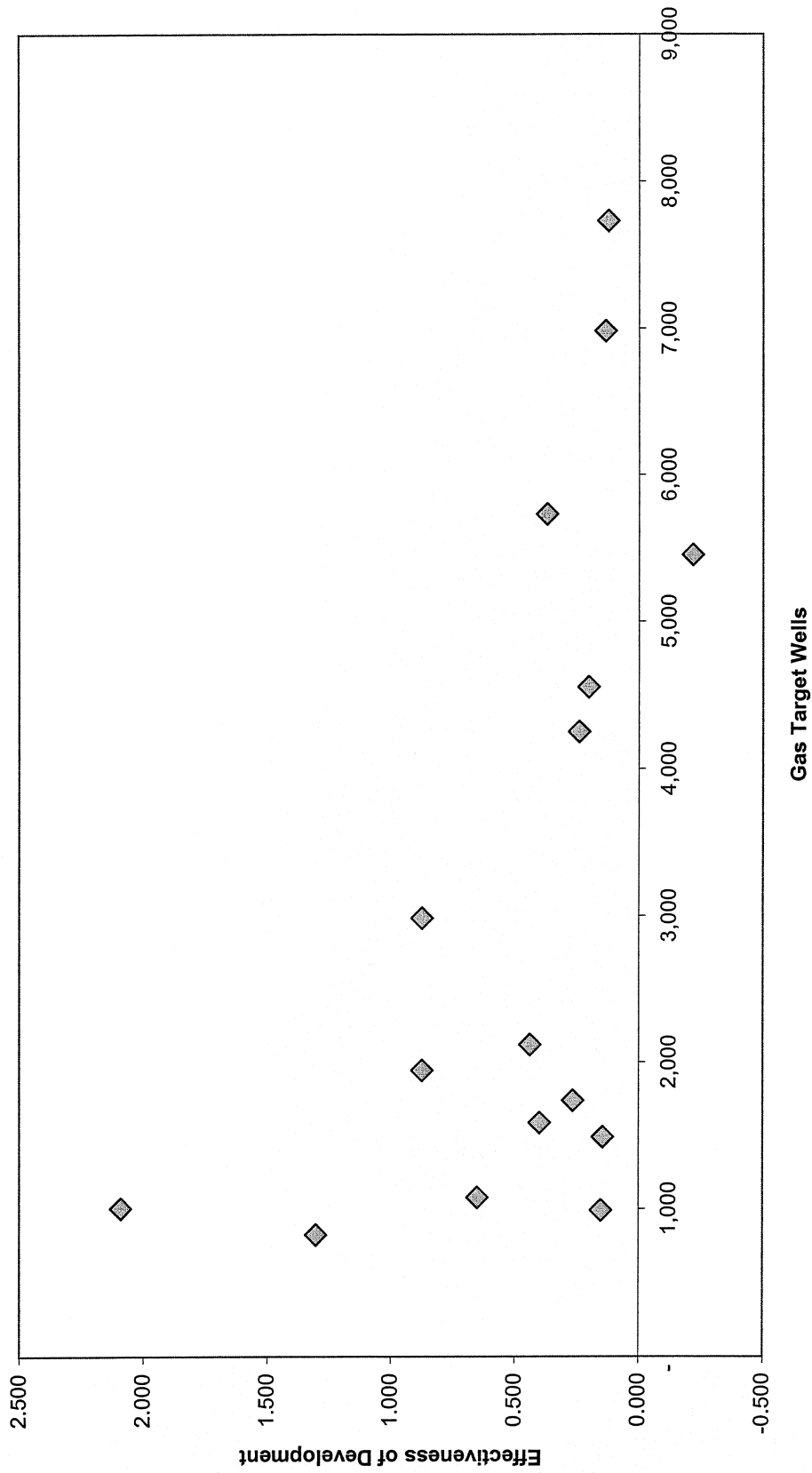


Cumulative Gas Target Wells From 1990

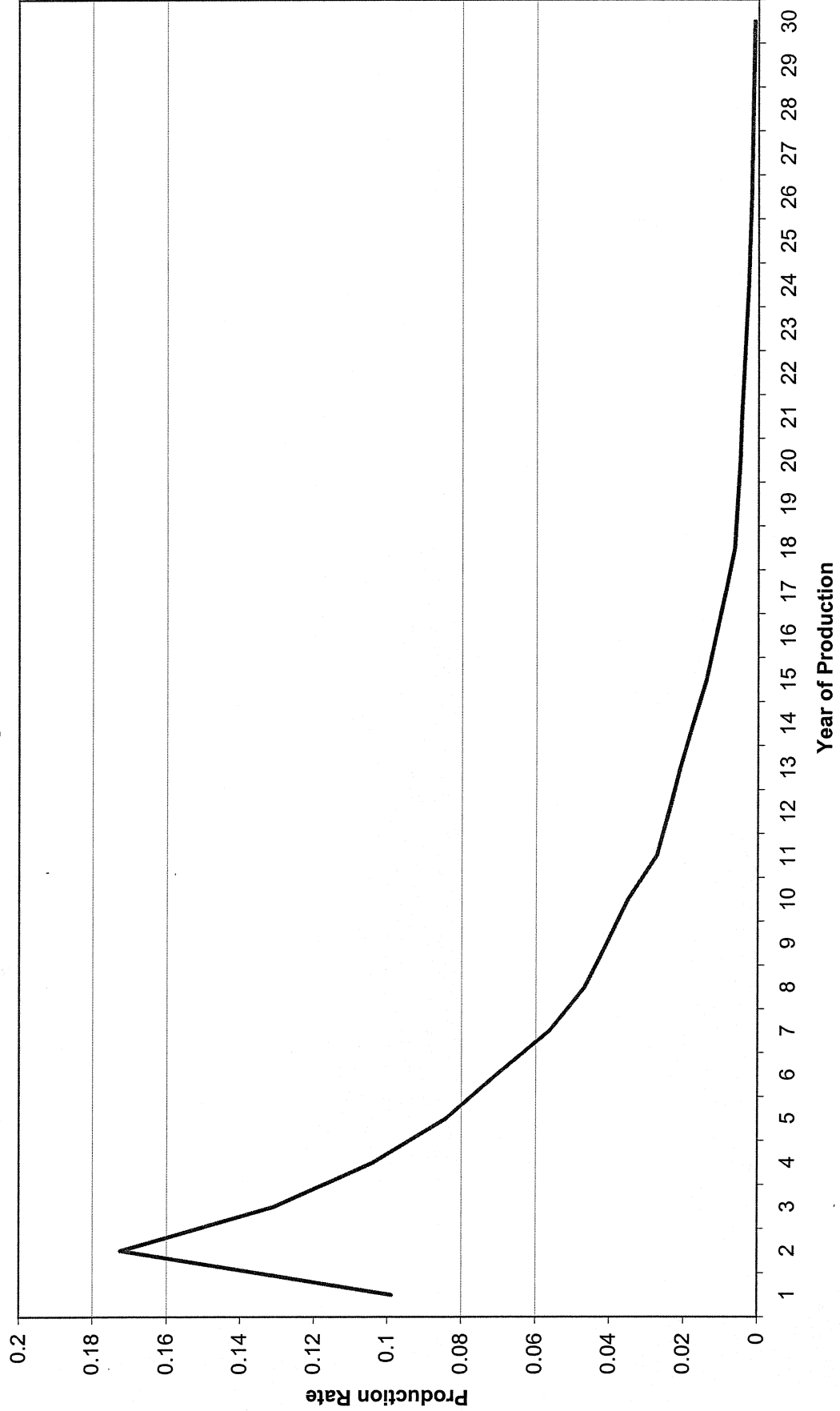


**RELATIONSHIP BETWEEN GAS TARGET EXPLORATORY FOOTAGE DRILLED AND THE
FINDING RATE OF DEVELOPMENT**

ROCKY MOUNTAIN AREA

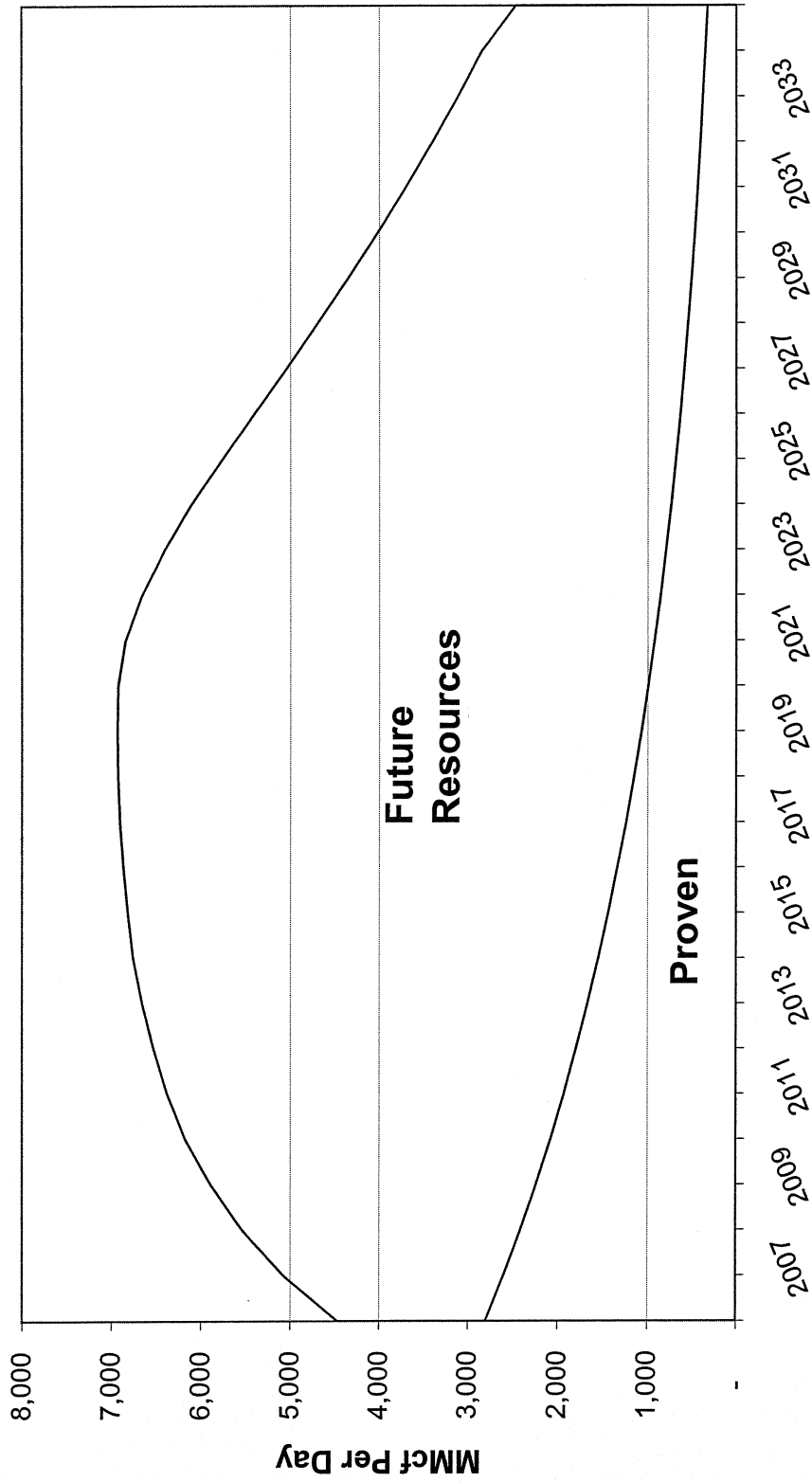


Production Rate Northern Rocky Mountain Region As a Percent of Original Gas Reserves

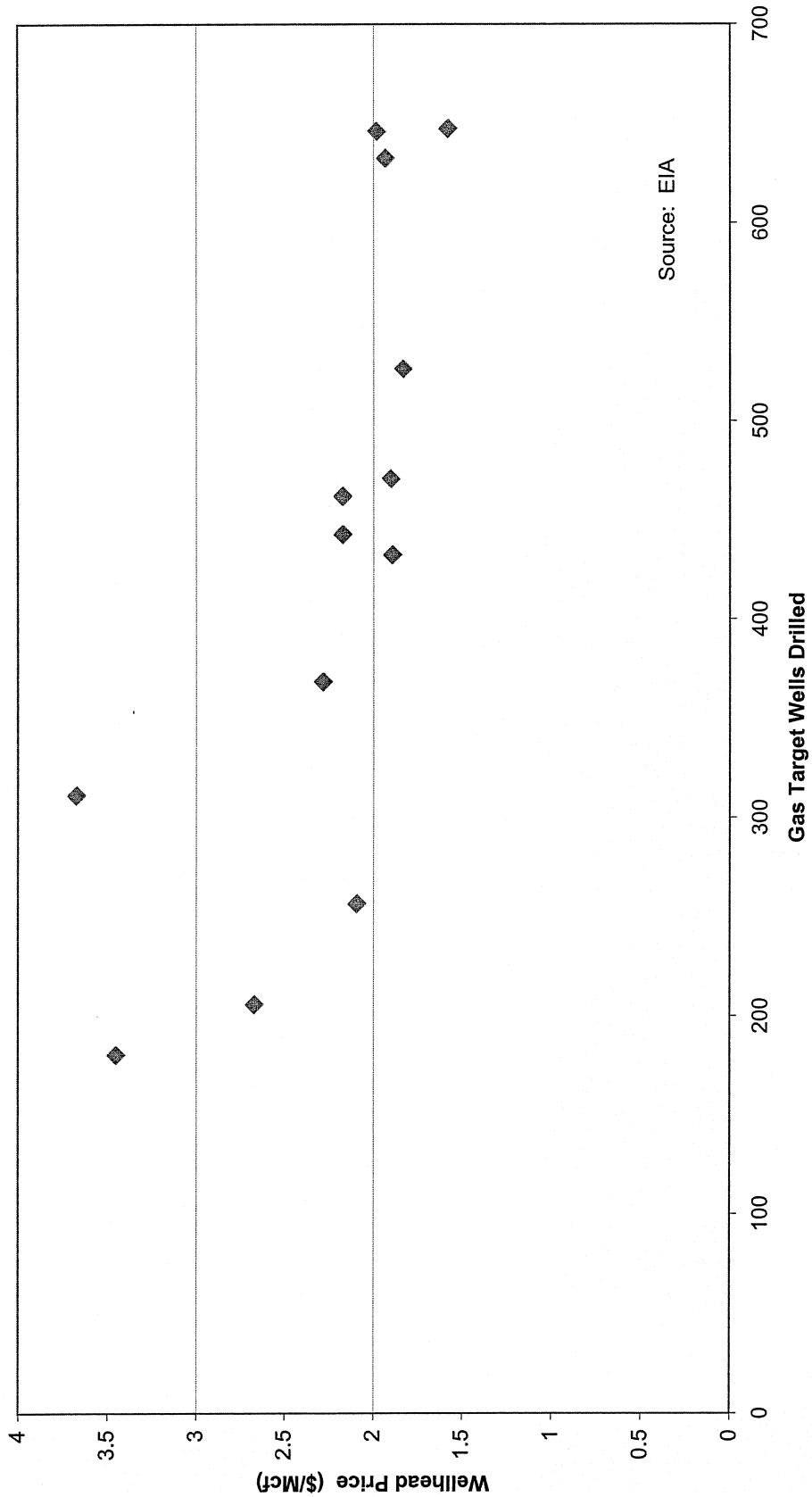


Natural Gas Productive Capacity

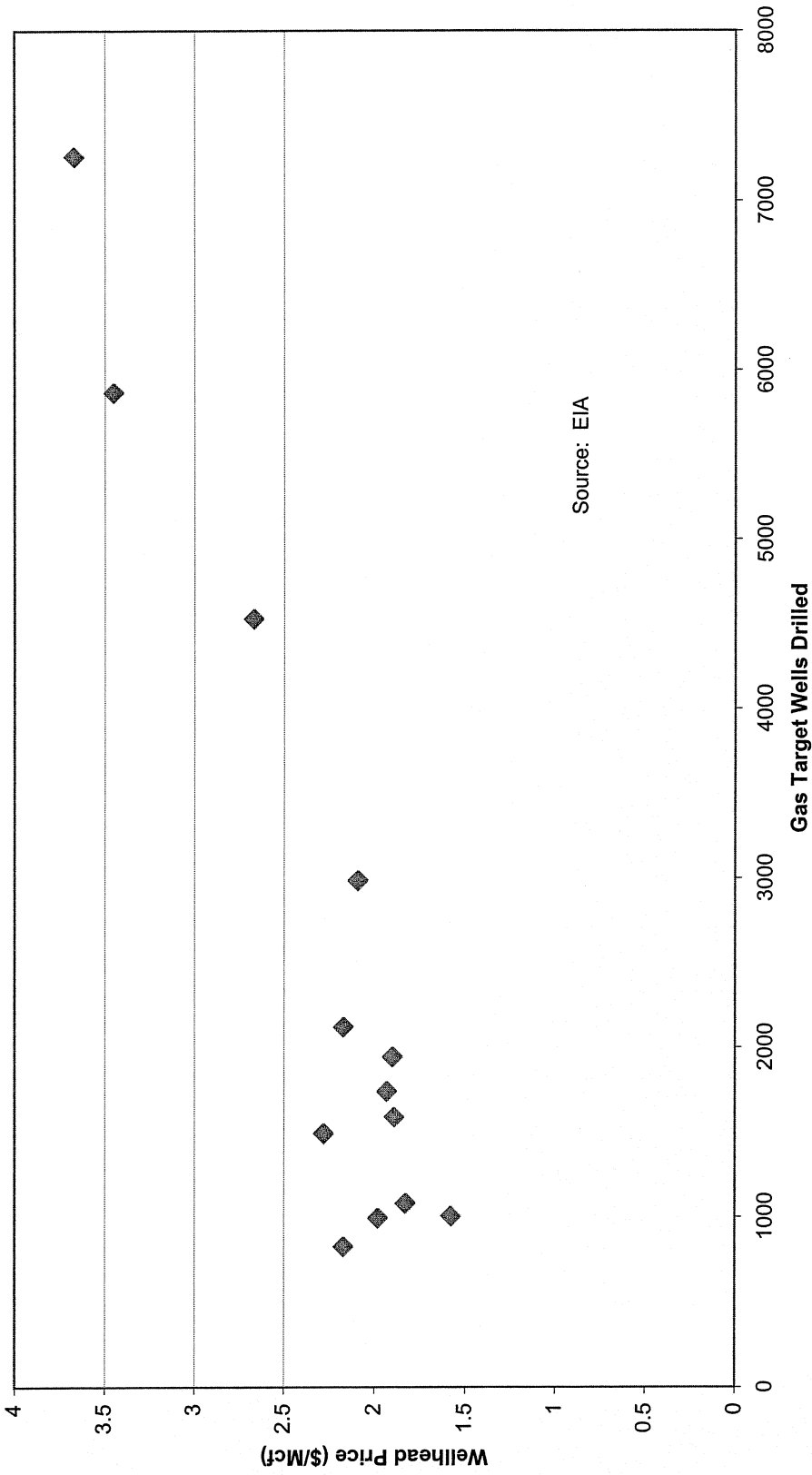
Colorado, Utah and Wyoming



Relationship Between Wellhead Price and Exploratory Drilling Rocky Mountain Area

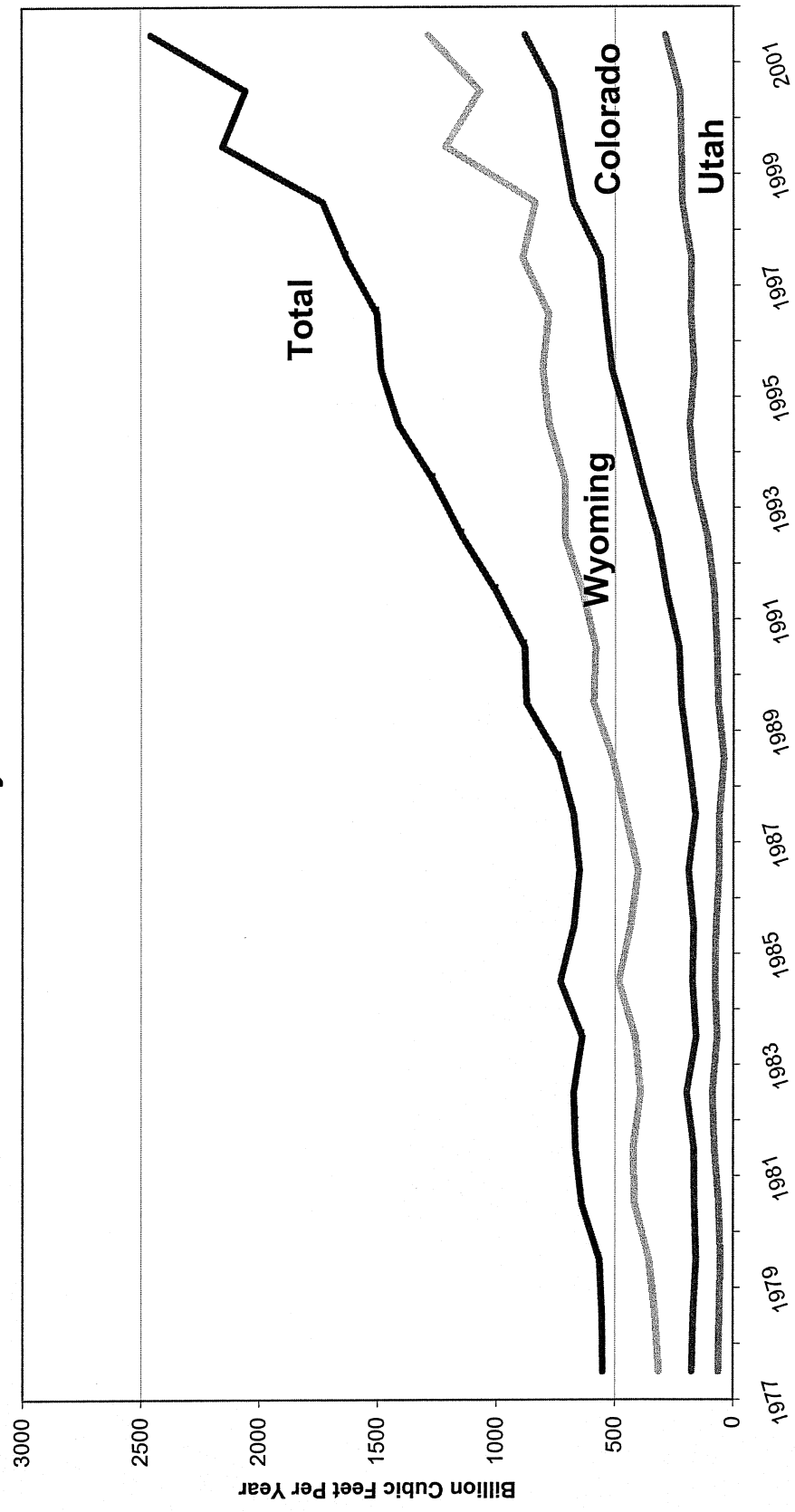


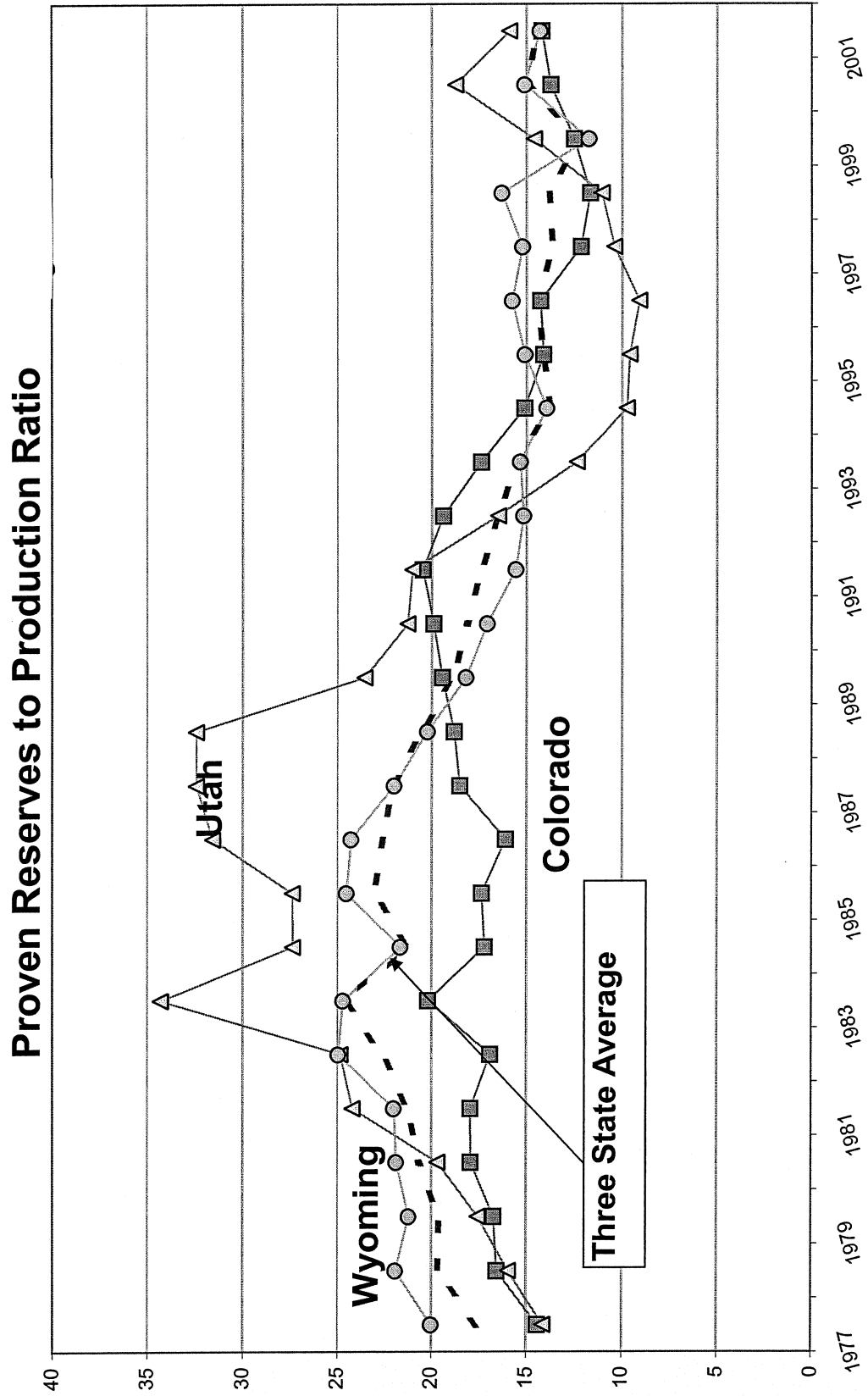
Relationship Between Wellhead Price and Development Drilling Rocky Mountain Area

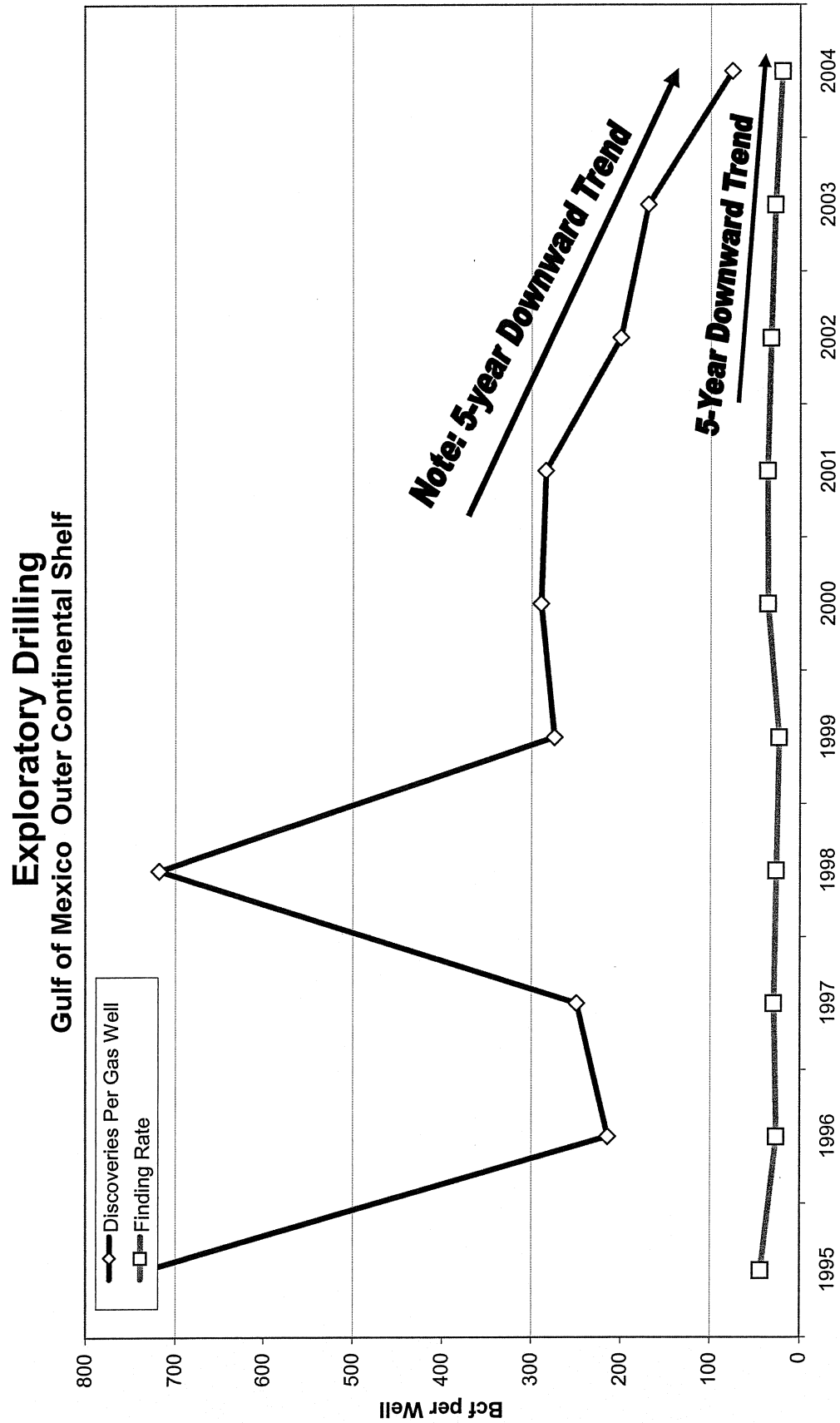


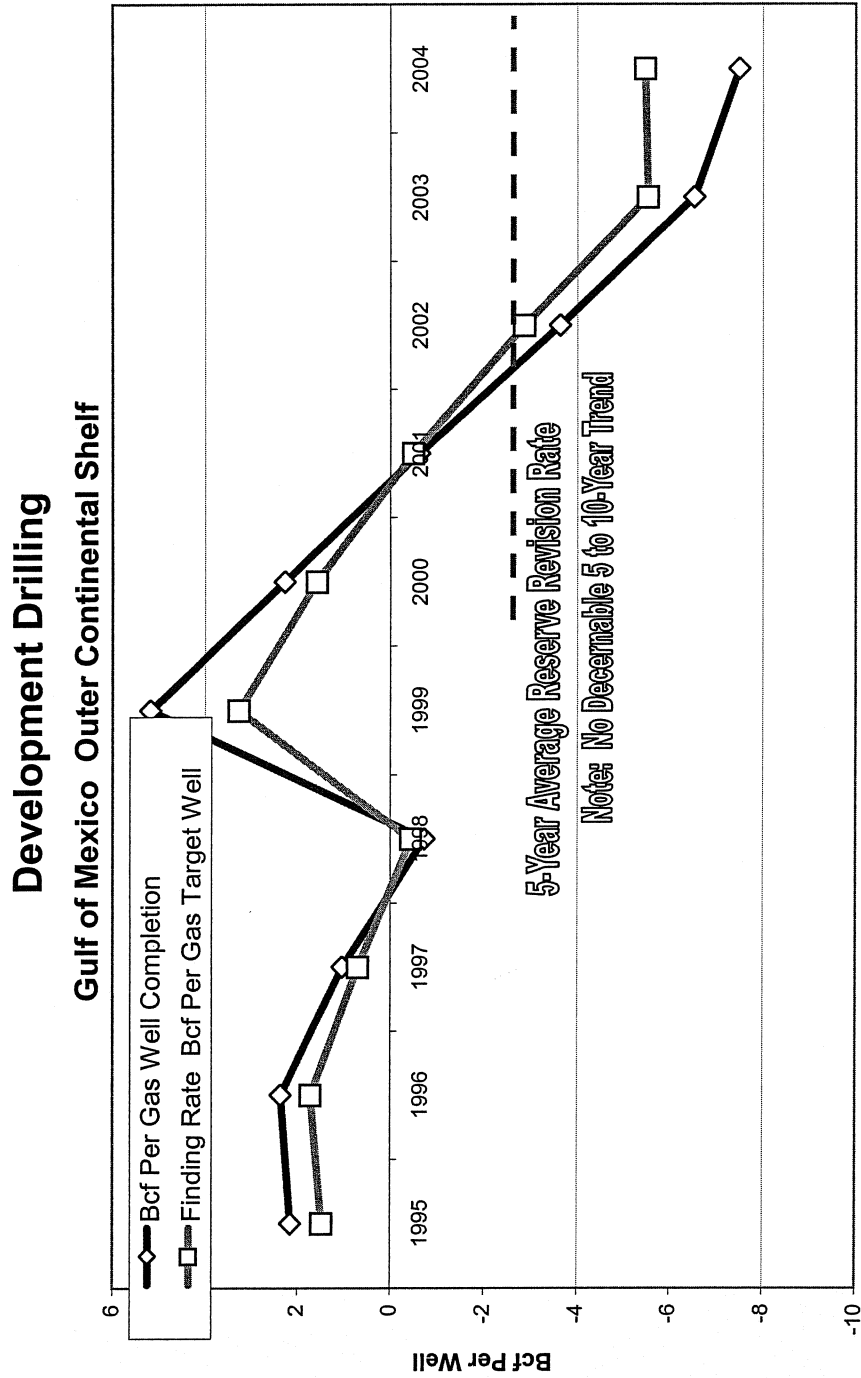
NATURAL GAS PRODUCTION

Northern Rocky Mountain Area

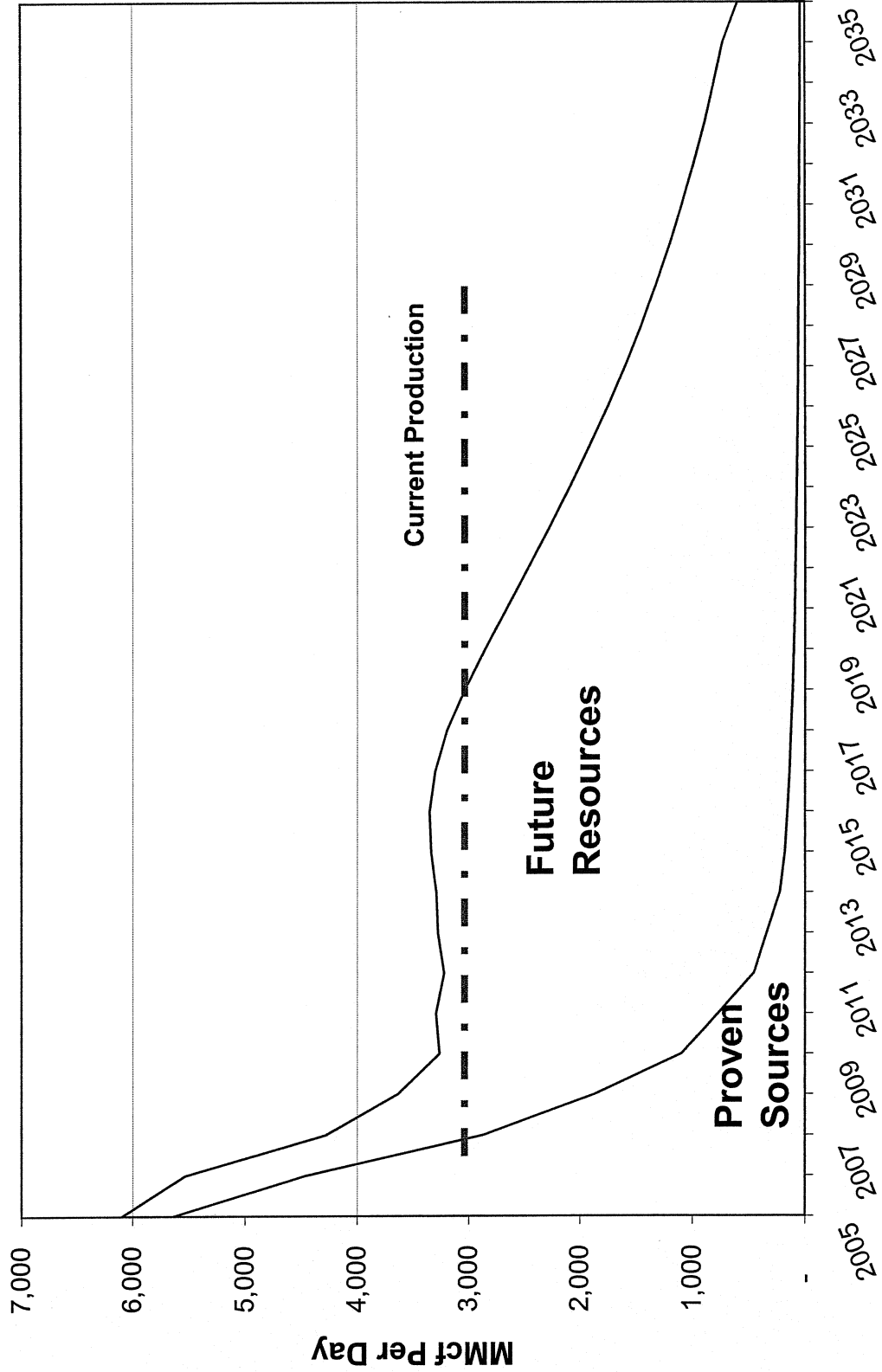




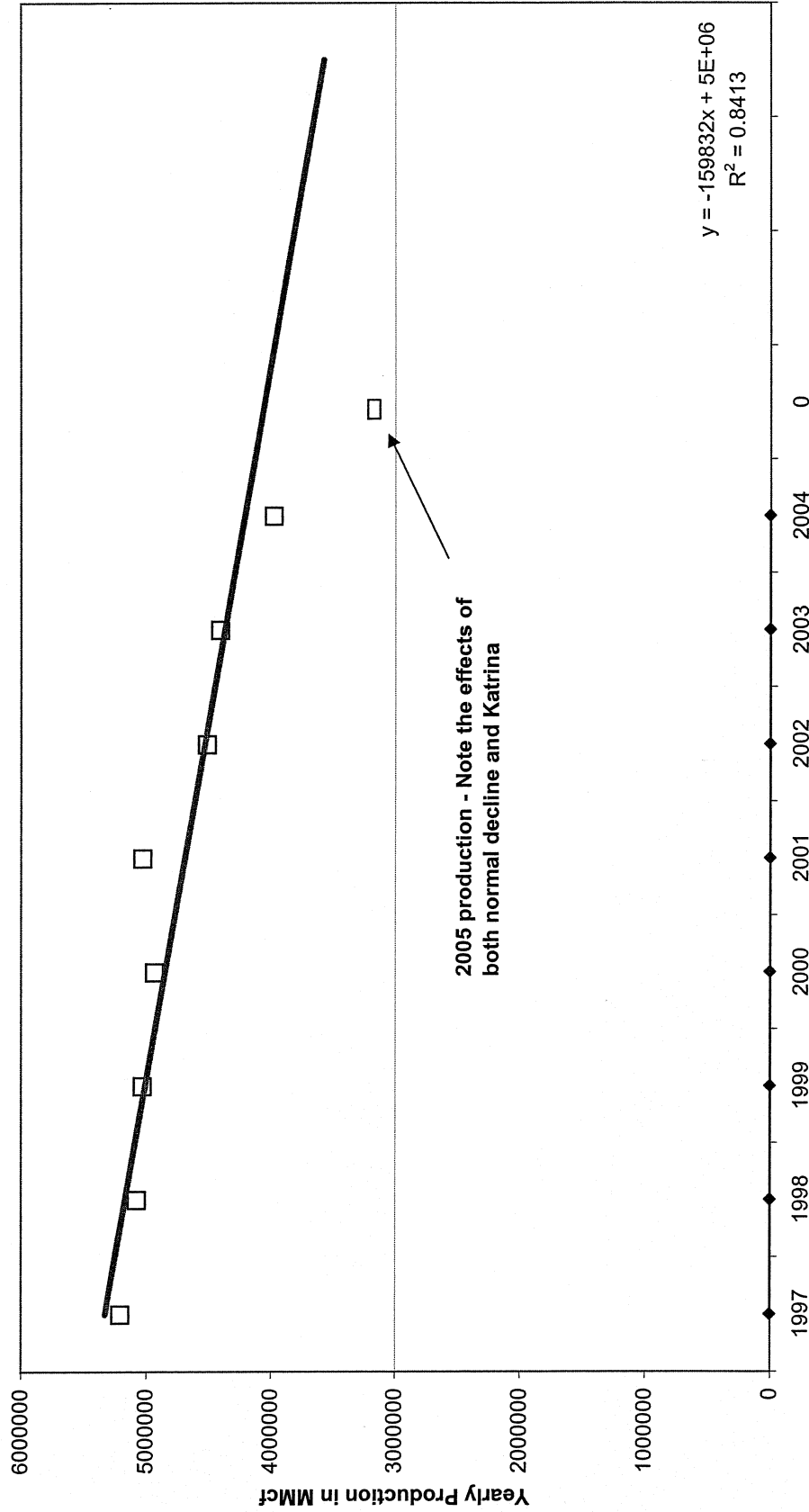




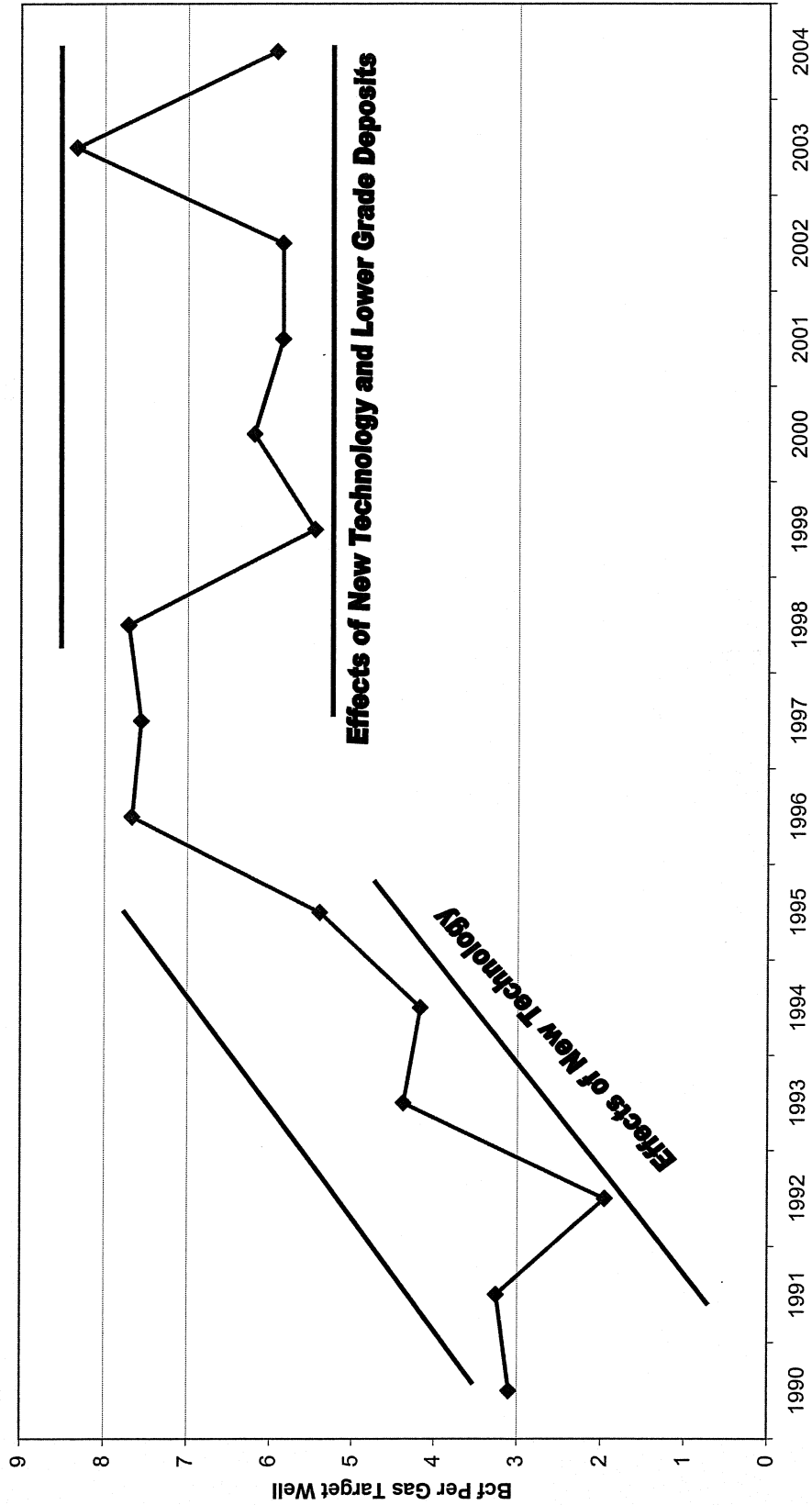
Natural Gas Productive Capacity Gulf of Mexico

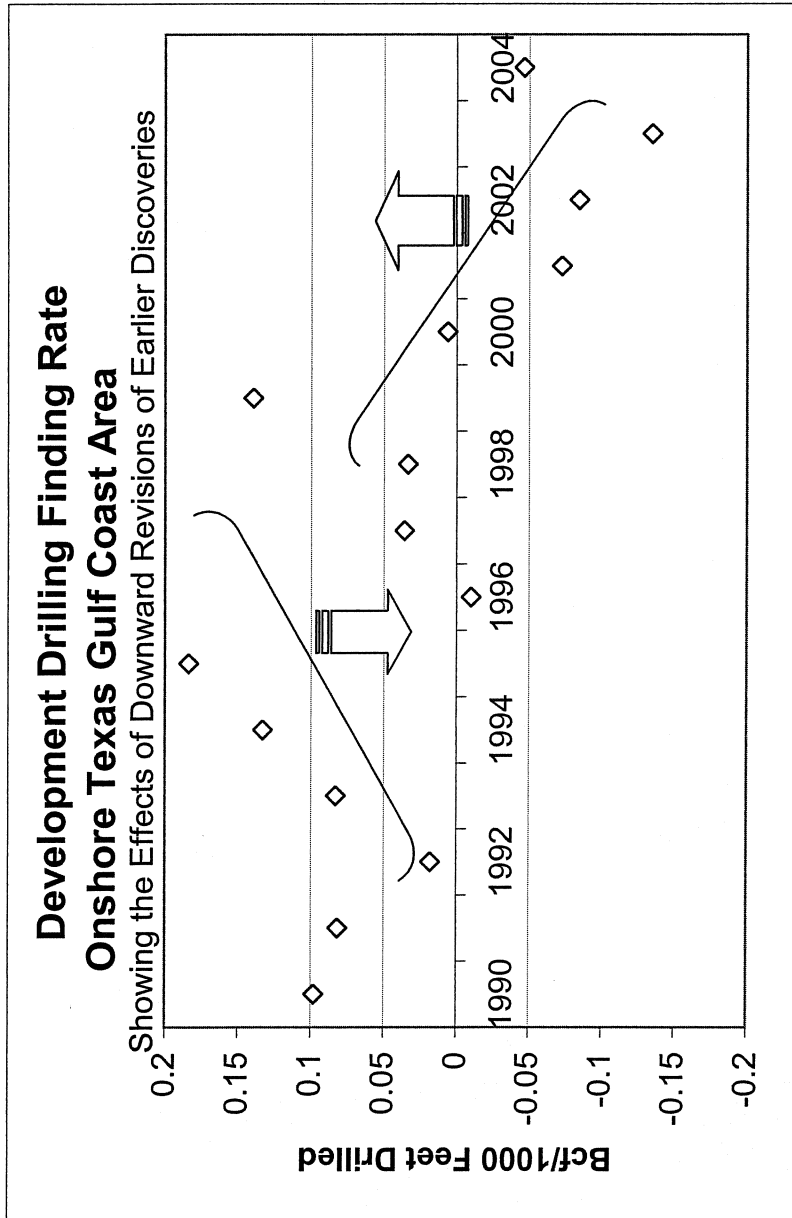


Natural Gas Marketed Production (MMcf) OCS Gulf of Mexico

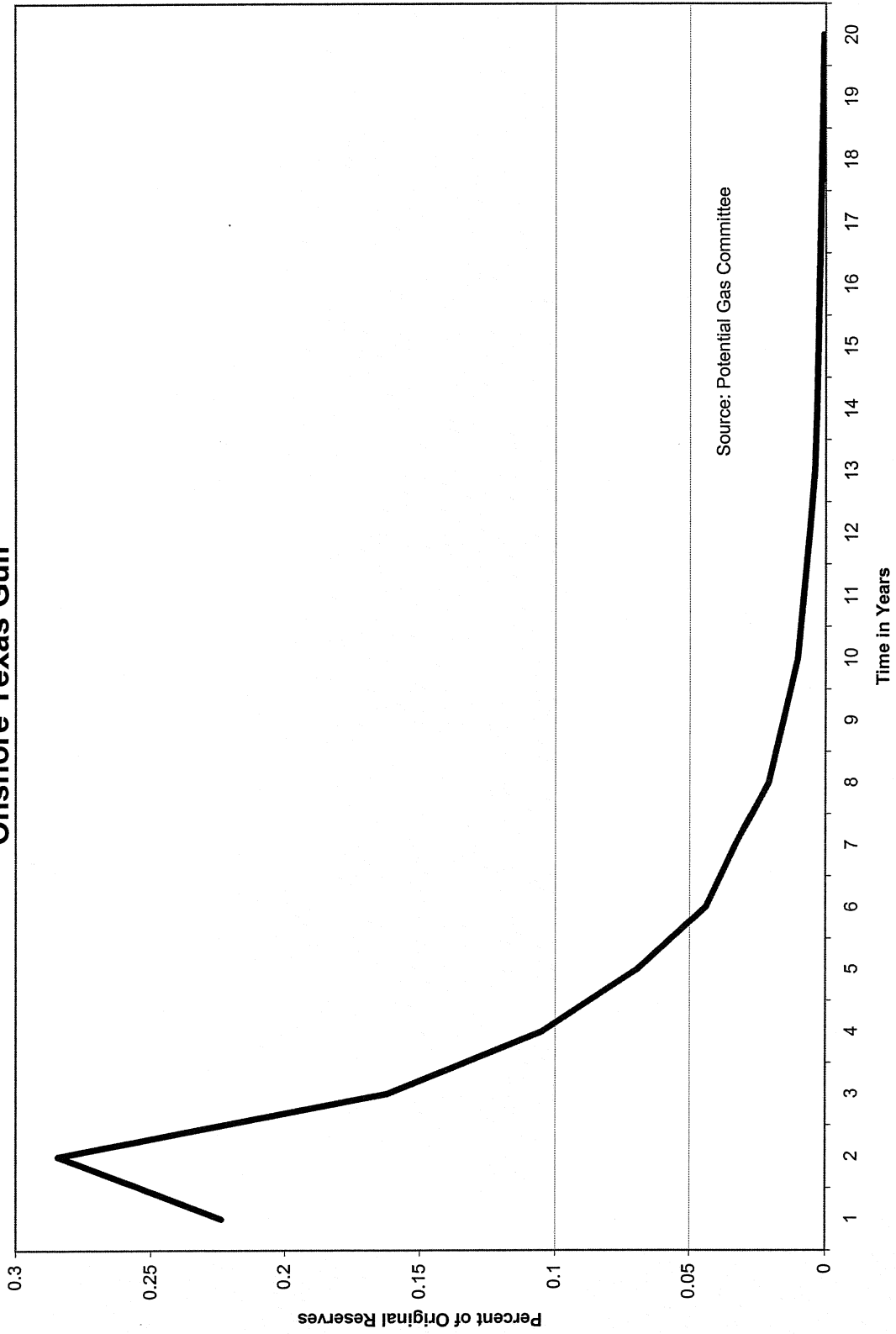


Exploratory Drilling Finding Rate Onshore Texas Gulf





Production Rate as a Percent of Original Reserves Onshore Texas Gulf



Natural Gas Productive Capacity Onshore Texas Gulf Coast

