EXHIBIT NO. S-10

FEDERAL ENERGY REGULATORY COMMISSION
OFFICE OF ADMINISTRATIVE LITIGATION

TRAILBLAZER PIPELINE COMPANY
DOCKET NO. RP03-162-000

PREPARED DIRECT TESTIMONY OF

COMMISSION STAFF WITNESS

KEVIN J. PEWTERBAUGH

ON

DEPRECIATION

MAY 22, 2003

WASHINGTON, D.C. 20426

FEDERAL ENERGY REGULATORY COMMISSION
OFFICE OF ADMINISTRATIVE LITIGATION

Prepared Direct Testimony of:
Kevin J. Pewterbaugh

in

Trailblazer Pipeline Company
Docket No. RP03-162-000

PART A–STAFF'S DEPRECIATION ANALYSIS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin J. Pewterbaugh. My business address is 888 First Street, N.E., Washington, D.C. 20426.

Q. By whom are you employed and what is your position?

A. I am employed by the Federal Energy Regulatory Commission (FERC) as a Petroleum Engineer in the Office of Administrative Litigation.

Q. Please briefly describe your educational background and training.

A. I received my Bachelor of Science degree in Petroleum and Natural Gas Engineering at The Pennsylvania State University in May 1979 and have been employed continuously by FERC since September 1979. In addition to my engineering education, I have completed three depreciation seminars given by Depreciation Programs, Inc., a commercial organization widely recognized for its expertise in depreciation related matters. I have also taken a course in Calgary, Alberta, Canada on natural gas reservoir engineering sponsored by Oil and Gas Consultants International, Inc. I am a member of the Society of Depreciation Professionals.

Q. **What are your duties at the FERC?**

A. My responsibilities have included, and continue to include, determining the appropriate depreciation rates in formal gas rate case proceedings, and providing support for such rates. In performing my duties, I have done gas supply and remaining economic life analyses and have estimated future gas production.

Q. **Have you submitted testimony in any other proceedings?**

A. Yes, I have submitted testimony in the rate cases shown in Exhibit No. S-11, Schedule No. 1.

Q. **What particular issues do you address in this proceeding?**

A. My testimony addresses the appropriate depreciation and amortization rates to be applied to the depreciable and amortizable plant of Trailblazer Pipeline Company (Trailblazer) to determine the proper depreciation and amortization expenses to be included in its cost of service. The depreciation rates apply to the depreciable plant contained in Trailblazer's transmission and general plant accounts. The amortization rate applies to Trailblazer's intangible plant. Separate depreciation rates have been calculated for Trailblazer's

"Existing Facilities" and for its "Expansion Facilities." I have also provided the proper depreciation rate to use if the Expansion Facilities are rolled in with the Existing Facilities.

The depreciation and amortization rates I determined for Trailblazer's plant were given to Staff witness Frances Segal for her use in determining the proper cost of service.

In the course of determining the appropriate depreciation rates, I determined the remaining economic life of Trailblazer's facilities. I also calculated the average remaining life and the percent of existing plant surviving at truncation, both with respect to Trailblazer's transmission facilities. The percent of existing plant surviving at truncation will be discussed later. I have given this information to Staff witness James S. Taylor for his use in determining the appropriate negative net salvage rate.

Q. Is Trailblazer recommending any change to its depreciation rates?

A. Yes, Trailblazer is proposing to change all of its transmission, general plant, and intangible depreciation and amortization rates.

Q. How do your depreciation recommendations compare to Trailblazer's depreciation rates?

A. I am recommending a change in Trailblazer's transmission and general plant accounts. I am accepting its intangible rate proposal. The Company's existing and proposed rates, as well as my recommendations are shown below:

Function	Gross Plant (3/31/03) ($)	Existing Rate (%)	Company Proposal (%)	Staff Proposal (%)
Transmission Existing Plant	283,200,082	3.60	2.90	0.90
Transmission Expansion	47,109,741	5.00	7.00	3.40
Transmission Combined	330,309,823	--	3.48 (calculated)	1.25
General	174,377	3.60	10.00	20.00
Intangible	90,746	33.30	0.00	0.00

This information is also provided in Exhibit No. S-11, Schedule No. 2. The dollar information was provided by Staff witness Segal. Please note that I calculated that the Company's transmission rate would be 3.48 percent if the expansion facilities were rolled in; the Company did not provide this value.

With respect to the transmission plant, based on adjusted gross plant balances as of March 31, 2003, of $330,309,823, my recommendations would decrease the Company's proposed annual depreciation expense by over $7,300,000. However, Staff witness Segal will determine the actual effect on the cost of service, based on the depreciation and amortization rates I provided her and the appropriate gross plant amounts.

Q. **Would you summarize your analysis with respect to the proper depreciation and amortization rates to apply to Trailblazer's depreciable and amortizable plant?**

A. With respect to Trailblazer's transmission facilities, Trailblazer is proposing a rate for its Existing Facilities that, absent any changes in plant, would recover the remainder of its investment in about ten years; under the same scenario, it would recover the remainder of its investment in its Expansion Facilities in about 14 years. I believe these time frames are too short for the Company's supply and market characteristics. Further, it does not make sense for the Expansion Facilities, which are compressor station equipment, to last longer than the existing pipeline upon which its usefulness will depend.

I determined the remaining economic life of Trailblazer's transmission facilities to be 35 years from December 31, 2001. This is the latest production and reserve data available at the time of the preparation of this testimony. My recommendation is based on a study that includes supply, demand, and competition. Trailblazer's supply area is primarily Colorado and Wyoming. I determined that the amount of reserves in this supply area can support production for at least the next 35 years. Demand for natural gas, as discussed later, both in Trailblazer's market area and nationally, is projected to increase in the future. These findings support the remaining economic life I have used for Trailblazer's facilities. Further, I conclude that it is premature to shorten Trailblazer's remaining life based on the uncertain effects of competition. The remaining economic life is used in the calculation of the depreciation rates. Based on that remaining economic life, I calculated a depreciation rate for Trailblazer's transmission facilities.

With respect to Trailblazer's general plant facilities, I used an average service life (ASL) approach to determine the appropriate depreciation rate for the general plant function. Using that approach, my analysis shows that the depreciation rate should be raised above the company's proposal, from 10.00 percent to 20.00 percent.

Finally, with respect to intangible plant, the account is fully accrued, and I agree with Trailblazer's proposal of a 0.00 percent rate.

Q. **Do you sponsor any Exhibits?**

A. Yes. Besides my testimony, which is designated as Exhibit No. S-10, I am sponsoring Exhibit Nos. S-11 and S-12. Exhibit No. S-11 contains the supporting schedules of my depreciation analysis. I have included a Table of Contents for Exhibit No. S-11 in the front of that exhibit. Exhibit No. S-12 contains my workpapers.

Exhibit No. S-10 is divided into three parts, A through C. **Part A** is subdivided into four main sections. Section I is this introduction, Section II presents my depreciation analysis for Trailblazer's transmission facilities, Section III presents my analysis for Trailblazer's general plant, and Section IV summarizes my depreciation analysis.

With respect to Exhibit No. S-11, Schedule No. 1 lists the other proceedings in which I have submitted testimony, Schedule No. 2 provides a summary of my depreciation and amortization rate recommendations, as well as the percent surviving at truncation data used by Staff witness Taylor in this proceeding. Finally, Schedule No. 3 provides a map of Trailblazer's facilities. I will describe each of the remaining schedules later in my testimony.

Part B of my testimony contains my discussion of the testimony of Trailblazer witness Geoffrey E. Simmons. **Part C** of my testimony contains my discussion of the testimony of Trailblazer witness Ronald Harrell.

II. STAFF'S DEPRECIATION ANALYSIS FOR TRANSMISSION FACILITIES

Q. Would you provide an overview of how you determined the appropriate depreciation rates for Trailblazer's transmission facilities?

A. Yes. Almost all of Trailblazer's investment is in transmission plant. The depreciation rate I determined is designed to recover this investment over the remaining economic life of Trailblazer's facilities.

The depreciation rate is determined from the remaining economic life, an adjustment for interim retirements, and the amount of the gross plant that is left to be recovered. The remaining economic life of the pipeline is generally the most important consideration in determining the depreciation rate. Most of this analysis goes toward determining the appropriate remaining economic life for Trailblazer's facilities.

In determining the remaining economic life, I first determined how long there will be a gas supply sufficient to support Trailblazer's operations; if there is no gas to transport, Trailblazer's operations will be over. The number of years that there will be a sufficient supply is determined through a study involving gas production, remaining reserves (reserves that have already been discovered), and an estimate of future reserves (gas that has not yet been discovered).

After determining how many years there will be a sufficient supply, which is also called the supply life, I discuss demand and competition. I have concluded that these factors will not cause Trailblazer to cease operations while there is still a sufficient supply. Therefore, the supply life in this case will equal the remaining economic life.

The next step after determining the remaining economic life is to make an allowance for interim retirements. These are retirements that will occur before the end of the remaining economic life. Not accounting for these retirements would lead to an underrecovery of the Company's investment at the end of the remaining economic life.

Finally, after determining the allowance for interim retirements, the depreciation rate is calculated based on the percentage of the Company's plant that has not yet been recovered.

Q. What is the basis of your recommendation?

A. I have developed my recommendation on the basis of my analysis, which is premised on the Commission's Uniform System of Accounts for Natural Gas Companies definition of depreciation, and applied guidelines set out in the opinion rendered in the United States Court of Appeals for the District of Columbia Circuit in Memphis Light, Gas and Water Division v. Federal Power Commission (Memphis), 504 F.2d 225 (1974).

The Commission's Uniform System of Accounts for Natural Gas Companies defines depreciation as:

> the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, 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. (Emphasis added.)

Consistent with these guidelines, service value (original cost less net salvage) should be allocated according to the total number of service units, such as Mcf (thousand cubic feet) of gas or units of time. The transportation of service units of gas, or passage of service units of time, represents the loss in service value, and that loss is premised on the concept that as the number of service units diminish, the service value of depreciable property also diminishes until it completely expires.

In the Memphis decision, the Court states:

> In order to be "just and adequate" a reserve life depreciation rate must be based upon the useful life of the particular property involved. We therefore believe that it is the Commission's

> obligation to make some reasoned estimate of the useful life of the property here involved, 43/ even though to do so would no doubt require an estimate of future reserves. We realize that such a prognostication would necessarily be only an estimate, but at least the Commission would thereby attempt to ascertain how the gas shortage had affected the useful life of this property.
>
> 43/ It is possible that insufficient reserves could have a greater effect on one type of company property, or property located in one area, than on other property. In such a case, the Commission could arrive at a composite depreciation rate, taking into account potentially differing useful lives, rather than as here, a uniform rate system wide.
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> 504 F.2d at 235 (emphasis by single underline in original; emphasis by double underline added, which highlights the requirement of an estimate of future reserves).

Q. Is remaining economic life the same as useful life?

A. In this context, the terms can be considered synonymous. Remaining economic life is the period, from a given point in time, during which property continues to provide service. As I am using the term, remaining economic life is defined by nonphysical reasons for retirement such as exhaustion of supply or lack of demand. Average remaining life, which is used in the depreciation calculation, but not in the remaining economic life determination, is an adjustment to the remaining economic life to account for interim retirements, which are retirements that occur before the end of the remaining economic life. The term, supply life, refers to how long a property will continue to provide service based on supply considerations alone. It is a factor in determining the remaining economic life, but it is not the only factor.

Q. What depreciation approach did you use to determine the appropriate depreciation rate for Trailblazer's transmission facilities?

I used the Straight-line Method, Remaining Life Technique (straight-line method) in my depreciation analysis.

Q. What is the straight-line method of depreciation?

A. The straight-line method is designed to recover the investment in equal annual installments over the useful life or the remaining economic life of the facilities, and is based on service units of time. This method is used to calculate a depreciation rate based on the remaining economic life of the asset to be depreciated. This rate is then applied to the depreciable base. Another name for the depreciable base is the gross plant (although land, which is not depreciable, must be removed from gross plant for depreciation purposes). The straight-line method allocates the recovery of the gross plant uniformly over the asset's remaining economic life, which results in a uniform charge to each generation of ratepayers.

Average service life (ASL) and average remaining life (ARL) are terms associated with the straight-line method. ASL applies to the average service life expectancy of a group of assets at installation when all units are new. The ARL applies to the average remaining life expectancy of a group of assets at any point in time after the date of initial installation.

Q. What is the depreciation formula used to calculate depreciation rates using the straight-line method?

A. The depreciation rate using the straight-line method is derived by dividing the percent of the net plant left to be recovered by the Average Remaining Life (ARL) of the facility. The ARL will be discussed later. The actual depreciation formula is given in Exhibit No. S-11, Schedule No. 4.

For Trailblazer, the critical factor in determining the proper depreciation rates is the ARL. The ARL is determined from consideration of both physical and economic factors, and is itself dependent on the remaining economic life determined for the Company. In my analysis, I first determined the remaining economic life due to economic factors; then I determined the ARL. Not all units of plant are expected to remain in service throughout the remaining economic life of the facility as a whole; some of the units will be retired early due to such factors as wear and tear or actions of the elements. The ARL takes these factors into account. If these factors are not accounted for, then the depreciation rate in the future will be applied to a smaller gross plant than that for which it was designed, resulting in a smaller annual expense, and ultimately, an underrecovery of the Company's investment. It is the ARL, not the remaining economic life, that is used in the depreciation formula to determine the depreciation rate.

Q. Mr. Pewterbaugh, please describe Trailblazer's facilities as they relate to your study.

A. Trailblazer facilities are divided into two groups: its Existing Facilities and its Expansion Facilities. Trailblazer's Existing Facilities stretches from Colorado eastward to Beatrice, Nebraska. Trailblazer has 436 miles of transmission lines, mainly in Colorado, and Nebraska, with a small amount in Wyoming. The above mileage is taken from Trailblazer's 2001 FERC Form No. 2: Annual Report of Major Natural Gas Companies (Form No. 2). Essentially all of Trailblazer's plant is functionalized as transmission.

Trailblazer's Expansion Facilities consist of compressor station plant. Trailblazer added two new compressor stations and upgraded an existing compressor station. A map of Trailblazer's system was included as Exhibit No. S-11, Schedule No. 3.

Q. Where does the gas transported by Trailblazer originate?

A. Trailblazer receives gas for transportation from the Rocky Mountain area, primarily from Colorado and Wyoming. Specifically, Trailblazer receives gas for throughput mainly from interconnections with Wyoming Interstate Company, Ltd., Colorado Interstate Gas Company, Public Service Company of Colorado, and KN Energy, Inc., near the western end of its system. This information was taken from the response provided by Trailblazer to Staff Data Request (JST-1), Item No. 3, its most recent flow diagram.

Determination of Remaining Economic Life for Transmission Facilities

Q. What is the general approach you used in determining the remaining economic life of Trailblazer's facilities?

A. The general approach I used in determining the remaining economic life for Trailblazer's facilities was first to determine the supply life. For Trailblazer's transmission facilities, most of its supply is from Colorado and Wyoming. I used these areas to determined the supply life for Trailblazer's facilities. This supply life will be applicable for both Trailblazer's Existing Facilities and for its Expansion Facilities.

To determine the supply life based on Trailblazer's main supply area of Colorado and Wyoming, I obtained historical production, remaining reserve and ultimate recovery data for this area, from 1977 through 2001. Ultimate recovery represents the sum of the cumulative production and the current estimate of remaining proved reserves. Ultimate recovery estimates are made at points in time, and increase as more current estimates are made and heretofore undiscovered reserves are added to the remaining proved reserves category. Remaining proved reserves are also termed simply remaining reserves.

I then extrapolated historical production and historical estimates of ultimate recovery into the future to determine the supply life of Trailblazer's facilities. When supply that can be produced economically is exhausted by production, the useful life of the facilities is over. I examined demand and competition to determine their effect on the supply life in determining a remaining economic life for Trailblazer's facilities. I determined that demand and competition will not negatively impact, or shorten, the supply life. In other words, supply life in this instance will be synonymous with remaining economic life.

In following the above approach for determining the remaining economic life of the transmission facilities, my testimony is divided into six parts:

(1) identifying the supply area involved,

(2) obtaining historical production, remaining reserves, and ultimate recovery data for the supply area,

(3) extrapolating ultimate recovery into the future,

(4) extrapolating production into the future,

(5) determining the supply life of Trailblazer's facilities, and

(6) discussing demand and competition, and determining the remaining economic life.

After the remaining economic life is determined, the depreciation rate is determined in the following two sections:

(7) adjusting the remaining economic life for interim retirements, and

(8) calculating the depreciation rate for Trailblazer's transmission facilities.

(1) Identifying the Supply Area Involved

Q. What is Trailblazer's main supply area?

A. Trailblazer receives gas mainly from Colorado and Wyoming. I performed my study for these areas. With Trailblazer just being a transporter of gas, rather than also an owner of gas, the specific locations of Trailblazer's supply may shift within this large area over time.

In its supply area, Trailblazer will receive throughput not only from production from discovered reserves, but also from production from future discoveries. I will discuss the supply from future discoveries later.

(2) Obtaining Historical Production, Remaining Reserves, and Ultimate Recovery Data

Q. Mr. Pewterbaugh, where did you obtain the historical production, remaining reserves and ultimate recovery data used in your analysis?

A. I obtained production, remaining reserves, and ultimate recovery data for Trailblazer's supply area from two publications of the Energy Information Administration (EIA). I obtained production and reserve information from its annual publication, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (EIA Annual Report); this data is as of December 31, 2001, the latest data available at this time. I obtained cumulative production information, from which I was able to calculated ultimate recovery, from its publication, U.S. Oil and Gas Reserves, By Year of Field Discovery.

Historical production and remaining reserve data is provided in Exhibit No. S-11, Schedule No. 5. For the year 2001, production was 2,168 Bcf, and remaining reserves was 30,925 Bcf.

Ultimate recovery data for the Colorado-Wyoming area is shown in Exhibit No. S-11, Schedule No. 6. Ultimate recovery for a particular year is the sum of the cumulative production up to that point and the remaining reserves as reported that year. I determined historical annual ultimate recovery levels for 1977 through 2001. As shown in Exhibit No. S-11, Schedule No. 6, ultimate recovery, as of the end of 2001, was 68,213 Bcf.

(3) Extrapolating Ultimate Recovery into the Future

Q. Why did you extrapolate ultimate recovery into the future?

A. I extrapolated ultimate recovery into the future because the current sum of the cumulative production and the estimated remaining proved reserves will not give a complete picture of the total amount of gas that will eventually be produced in Trailblazer's supply area. Future discoveries will also be made and subsequently produced. Extrapolating historical estimates of ultimate recovery accounts for these future discoveries. The existence of future discoveries will be supported in more detail later. Extrapolating historical estimates of ultimate recovery results in the maximum level that the ultimate recovery will attain. I have termed that maximum level the "final" ultimate recovery level to distinguish it from historical or intermediate ultimate recovery levels.

Q. **How did you extrapolate ultimate recovery into the future?**

A. I extrapolated ultimate recovery into the future using the least squares curve fitting technique to fit an S-Curve to the historical data. This curve traces the shape that estimates of ultimate recovery are expected to have: slowly increasing as a producing area is initially discovered and developed, increasing at a greater rate as development of the area increases, and finally slowly increasing again as an area reaches its mature phase, with most of the area explored and developed. The preceding description follows an S-shape, which is also the shape of the S-Curve, and shows that the application of the S-Curve is appropriate. Further support for using an S-Curve for ultimate recovery will be given later.

Q. **What is the least squares curve fitting technique and why do you use it?**

A. This technique provides the estimate through the given data that has the least amount of deviation from the given data for the type of curve chosen. In other words, this technique provides the estimate that is closest to the actual data, for the type of curve chosen. This technique uses mathematical formulas to calculate the best fit curve through the given data.

The results of my extrapolations of the ultimate recovery data is given for the Colorado-Wyoming supply area in Exhibit No. S-11, Schedule No. 7. Pages 1 through 3 of the schedule provide a table showing annual estimates of ultimate recovery, while page 4 of the schedule presents the ultimate recovery information graphically, from which the fit can be seen visually.

Q. **You extrapolated ultimate recovery using an S-Curve; how did you arrive at the final ultimate recovery levels?**

A. I arrived at the final ultimate recovery level by determining the point when the rate of change between the annual ultimate recovery estimates reaches a maximum. On a smooth curve, the difference between an ultimate recovery estimate from one year to the next will increase for a number of years. Eventually, this difference will reach a maximum. After that, the difference between ultimate recovery estimates will become progressively smaller each year as the curve flattens out. The point at which the maximum difference occurs--when the annual differences stop getting larger, and start getting smaller--is termed the inflection point. The ultimate recovery level will increase each year, but after the inflection point, it will increase at a decreasing rate. I used the inflection point to determine the final ultimate recovery level.

I calculated the annual changes in the actual historical ultimate recovery estimates as shown in Exhibit No. S-11, Schedule No. 7, pages 1 through 3, under the column "Change in Actual Ult. Rec." As can be seen from this schedule, the largest recent change occurred in 2001. This can be considered a conservative estimation because the inflection point may not have actually been reached yet. The later the inflection point, the greater the final ultimate recovery level.

Also in Exhibit No. S-11, Schedule No. 7, Pages 1 through 3, I have calculated the amount of change in the annual ultimate recovery levels as given by the estimated curve. The annual changes in the estimated curve are determined, in part, by the final ultimate recovery level--changing the final ultimate recovery level changes the differences in ultimate recovery estimates from year to year and changes the inflection point of the curve. I have adjusted the final ultimate recovery level until the inflection point in the estimated data occurs in the same year as the inflection point in the actual data, 2001. With this inflection point, the corresponding final ultimate recovery level is 115,000 Bcf for Trailblazer's supply area.

Q. **What amount of undiscovered gas corresponds to this ultimate recovery level?**

A. The final ultimate recovery level, or the maximum level that ultimate recovery will attain, is the sum of the cumulative production and the remaining reserves after all of the reserves have been discovered. For the Colorado-Wyoming area, I calculated the final ultimate recovery level as of December 31, 2001. I determined that level to be 115,000 Bcf. This level consists of cumulative production of 37,288 Bcf, and remaining discovered reserves of 30,925 Bcf (both shown in Exhibit No. S-11, Schedule No. 6), leaving a remaining undiscovered reserves level of 46,787 Bcf.

Q. Is this level of undiscovered reserves of 46,787 Bcf the level that corresponds to your economic remaining life recommendation of 35 years?

A. No, my recommendation incorporates a smaller amount as will be discussed later.

(4) Extrapolating Production in the Future

Q. Why did you extrapolate production into the future?

A. The final ultimate recovery level is only one component necessary to determine the supply life; how quickly the reserve portion of the final ultimate recovery level will be exhausted, or produced, is also necessary to determine the supply life. To determine this factor, I extrapolated production into the future based on the historical annual production that was reflected in Exhibit No. S-11, Schedule No. 5.

Q. On what basis do you extrapolate production into the future?

A. For a given supply area, it is reasonable to assume that production will increase for a period of time and then begin to decline. Production will not increase indefinitely into the future because of the finite remaining resource base. Instead, production will achieve a maximum annual level at some point in time, at the peak year, and then begin to decline.

Production from a given producing area is expected to follow the shape of a bell-shaped curve, starting slowly as the area is first discovered and developed, increasing to some peak year of production as the area becomes fully developed, and then decreasing as reserves are exhausted.

The approach that I have used is based on the probability-type model as developed originally by M. King Hubbert (see his chapter in Oil and Gas Supply Modeling, U. S. Dept. of Commerce, May 1982). The theory predicts that natural resources will be discovered and produced in a way that resembles a bell-shaped curve. The Onshore South Louisiana area, for example, has shown this bell-shaped trend in its natural gas production history.

This theory also supports the use of the S-Curve for extrapolating historical ultimate recovery levels into the future. Ultimate recovery is composed of cumulative production and reserves until such time as all the reserves are produced and become part of the cumulative production total. Cumulating annual production estimates as given by a bell-shaped curve will result in a cumulative production curve with an S-shape. Therefore, using an S-Curve is appropriate for estimating cumulative production and ultimate recovery.

Historical production from the Colorado-Wyoming supply area is still increasing. I used a bell-shaped curve fit to historical annual production, in conjunction with my ultimate recovery estimate, to determine the supply life for this area and, therefore, for Trailblazer.

Q. How did you extrapolate production into the future?

A. I extrapolated production into the future using the least squares method of fitting a bell-shaped curve to the historical production data. The bell-shaped curve is determined from the historical data and from the peak year, which is the year in which the maximum annual production will occur. The least squares calculations I performed give a value for R-Squared (R^2) for each curve, which is a measure of the goodness of fit. The values for R^2 range from 0.00 to 1.00, with 0.00 being the worst fit and 1.00 being the best fit. The R^2 values for the least squares curve I used to extrapolate production is approximately 0.88 for the Colorado-Wyoming supply area, which represents an acceptable fit. This curve uses a peak year occurring in 2016. The curve I calculated is shown both numerically and graphically in Exhibit No. S-11, Schedule No. 8.

Q. How did you determine which peak year to use?

A. When historical data shows that the peak year has already occurred, that date is used. However, for the Colorado-Wyoming supply area, historical production is still increasing; therefore, another approach to choosing a peak year must be used.

It is reasonable to assume that production will ultimately recover as large a percentage of reserves as possible. I tried different peak years until the cumulative production curve first met or exceeded the final ultimate recovery level.

Exhibit No. S-11, Schedule No. 9, shows the results of cumulative production curves based on peak years of 2014, 2015, 2016, and 2017. From this schedule, it can be seen that a cumulative production curve based on a peak year of 2014 never attains the final ultimate recovery level, while a curve based on a peak year of 2015 does. A peak year of 2015 is the earliest peak year that meets the final ultimate recovery level. Bell-shaped curves with peak years before the year 2015 would not be as acceptable, given the ultimate recovery curve, because production following these curves will recover less of the reserve portion of the final ultimate recovery level, than a curve with a peak year of 2015, and will never reach the final ultimate recovery level. The year 2015 is the earliest peak year that results in a curve where cumulative production reaches the final ultimate recovery level. This would normally have been the peak year I would have chosen. However, I believe a curve based on a peak year of 2015 would reach the final ultimate recovery level too slowly. As can be seen from Exhibit No. S-11, Schedule No. 9, this extrapolation would not reach the ultimate recovery level of 115,000 Bcf until the year 2074, at which time the annual production would be only 38 Bcf. The year 2016 is the next earliest peak year. It reaches the final ultimate recovery level in 2052--22 years sooner than the other choice, which makes sense considering the anticipated future demand for natural gas, as will be discussed later. When this estimate reaches the final ultimate recovery level, the annual production would be 497 Bcf, more than ten times the amount using a peak year of 2015. For these reasons, I used a curve based on a peak year of 2016 to determine the supply life for the Colorado-Wyoming area.

Q. Why did you use a curve with the peak year of 2016 rather than some later peak year that will recover the reserves faster?

A. A curve could be chosen with a peak year out far enough that production would never decrease, but simply keep increasing until the reserves were depleted. However, this is not realistic based on how gas fields are depleted. The characteristic of producing natural gas is for production to decline from a peak as the reserves are exhausted. My approach of using the earliest peak year that recovers the final ultimate recovery level results in the most complete curve. I believe changing the peak year from this approach by increasing it by only one year best represents what may happen.

If I were to use a peak year of 2025, for example, it would more closely track the more recent actual production data (see Exhibit No. S-11, Schedule No. 8, for a graph of the estimate using a peak year of 2016), and it still would not exhaust the final ultimate recovery level until 2034. The annual production at that time, however, would be 2,522 Bcf, which is greater than the current (2001) annual production level of 2,168 Bcf, and it would not have as complete of a bell-shaped curve as a curve based on a peak year of 2016. I do not believe that a peak year after the year 2016 is appropriate.

(5) Determining the Supply Life of Trailblazer's Facilities

Q. How did you use the extrapolation of annual production in determining the supply life?

A. The year in which reserves are exhausted by the cumulative production curve is the endpoint of the remaining economic life. This occurred in the year 2052, or 51 years from the year 2001 (as can be seen in Exhibit No. S-11, Schedule Nos. 8 and 9). I have shortened this length of time to 35 years, considering estimates much beyond 35 years to be too speculative, recognizing that estimates become more speculative the further into the future one goes. I have used this 35-year period as my recommendation for the supply life for Trailblazer's transmission facilities. At the end of this 35-year period, production is projected to still be about 61 percent of the current amounts (1,330/2,168), which is a significant amount. At this point the ultimate recovery level would be 101,717 Bcf, as shown on Exhibit No. S-11, Schedule Nos. 8, Page 2 of 3 pages, and Schedule No. 9. This amount is made up of, as of December 31, 2001, cumulative production of 37,288 Bcf, and remaining reserves of 30,925 Bcf, both shown in Exhibit No. S-11, Schedule No. 6, leaving an undiscovered reserves level of 33,504 Bcf. This is about 72 percent of the total undiscovered level I calculated of 46,787 Bcf, and can therefore be considered conservative.

Q. What support do you have that the final ultimate recovery level will be greater in the future than the current ultimate recovery level?

A. There are three considerations that support the position that the ultimate recovery estimate will continue to grow: (1) historical additions to proved remaining reserves in Trailblazer's supply area, (2) recent and future estimated drilling for new reserves in this area, and (3) estimates of undiscovered gas remaining in this area as published from an independent source.

Q. Please describe the historical additions to which you refer.

A. I refer to the annual additions to reserves, which are also additions to the ultimate recovery, that occur each year.

The EIA Annual Report publishes reserves that were discovered each year. For the Colorado-Wyoming area, these reserve additions are shown in Exhibit No. S-11, Schedule No. 10, and show that from 1996 through 2001, additions in the Colorado-Wyoming area have averaged 2,130 Bcf a year. It is reasonable to believe that additions will continue in the future.

Q. Please describe the drilling information to which you refer.

A. The Oil and Gas Journal, a weekly publication, annually provides its review of the previous year's exploratory drilling and its forecast of the next year's exploratory drilling. The purpose of exploratory drilling is to find undiscovered or unproved reserves. Its latest annual report, for 2002, shows an estimate of 351 exploratory wells drilled in the

Colorado-Wyoming area in 2002. It also forecasts 284 exploratory wells to be drilled in 2003. These data are shown in Exhibit No. S-11, Schedule No. 11.

The drilling figures on Exhibit No. S-11, Schedule No. 11, do not mean that all these wells were or will be completed as successful gas wells, but it shows that there is a level of interest in Trailblazer's supply area, and the expectation that undiscovered or unproved reserves still exist.

Q. Please describe the independent source to which you refer as support for the existence of heretofore undiscovered reserves in the Colorado-Wyoming area.

A. The Potential Gas Committee (PGC) is an independent source of undiscovered gas levels. According to the PGC, "The objective of the Potential Gas Committee is to provide estimates, based on expert knowledge, of the potential supply of natural gas, which, together with estimates of proved reserves of natural gas, make possible an appraisal of the nation's long-range gas supply." The PGC publishes its estimates biennially in its report, Potential Supply of Natural Gas in the United States. They have prepared and published estimates for over 30 years. This report provides the PGC's estimate of undiscovered gas in existing fields, and from new field discoveries. The PGC's latest report is as of December 31, 2000.

Q. How does the estimate from the independent source for the Colorado-Wyoming supply area compare to your estimate?

A. Comparisons between this estimate and my estimate are shown in Exhibit No. S-11, Schedule No. 12, Page 1 of 2 pages.

As discussed earlier, my estimates of undiscovered reserves are calculated by subtracting from my ultimate recovery level, the gas that has already been produced and the gas that has already been discovered and categorized as remaining reserves. For the Colorado-Wyoming supply area, my estimate of undiscovered reserves based on a 35-year life, shows that it is below the PGC estimate. My estimate is 33,504 Bcf as of December 31, 2001. The PGC estimate of undiscovered gas is 87,459 Bcf as of December 31, 2000. Note that the PGC estimate is as of a year before my estimate. Bringing the PGC estimate up to 2001 would not significantly change the difference between its estimate and my estimate.

The PGC refers to its estimates as "potential resources", and states that its estimates "represent potential natural gas resources expected that, in the judgment of its members, can be recovered by future drilling under the conditions of:

1. adequate economic incentives in terms of price/cost relationships, and
2. current or foreseeable technology."

It also states that "No consideration is given whether or not this resource will be developed; rather, the estimates are of resources that could be developed if the need and economic incentive exist." (Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee, December 31, 2000, page 187.)

I have used the term undiscovered reserves instead of undiscovered resources. This term does not mean that undiscovered reserves have achieved the same level of certainty as discovered or remaining reserves, but in the context of my depreciation analysis, I consider undiscovered reserves, to the extent I use them, to be gas that will be discovered and produced.

Q. Mr. Pewterbaugh, what categories of the PGC's estimates did you use to compare with your results?

A. The PGC divides its estimates into three categories: probable, possible, and speculative. Probable resources refers to undiscovered gas connected with known fields, possible resources refers to undiscovered gas connected with known productive formations, and speculative resources refers to undiscovered gas connected with formations that have not yet proven to contain natural gas resources. A definition of these categories is given in Exhibit No. S-11, Schedule No. 13. I have used the categories of probable and possible in my comparison.

The PGC gives three estimates for each of the above categories: minimum, maximum, and most likely. I have used the most likely estimate for comparing with my estimate. The PGC states of the "most likely" category:

> The most reasonable estimate of the existence of traps and accumulations and the most reasonable assessment of source bed, yield factor and reservoir conditions. The probability is highest that these conditions prevail in the estimator's judgment and that the estimated quantity of gas resources would be present. Such conditions lead to the most likely estimate of the resource.
>
> Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee, December 31, 2000, page 192.

I will discuss the PGC further in my discussion of Trailblazer witness Harrell's testimony.

Q. Do you believe the PGC estimate should be the controlling estimate in determining the supply life from the Colorado-Wyoming area?

A. No, it is just one estimate, and is used as support for the reasonableness of my estimate. Further, subsequent PGC estimates may be larger than the current estimate as more exploration occurs, leading to the inclusion of undiscovered gas that was excluded in the PGC's latest estimate. I believe that the PGC estimate will increase as the demand for natural gas increases during the projected 35-year supply life for Trailblazer. The simple scenario is that if a supply deficiency should occur, the result will be an impetus to increase supply. This concept is supported by Standard & Poor's, Platt's in its report, U.S. Energy Outlook, Fall/Winter 1999-2000. In this report, it states on page 69:

> The forecast reflects the primacy of demand in driving natural gas markets. Environmental policies that encourage the use of natural gas will inexorably lead to rising demand. And demand will likely outpace domestic supply growth for at least the medium term.

> Thus, prices will rise, and higher prices will bring new sources of supply. . . . In sum, both new technology and new sources should eventually achieve the requisite supply. (Emphasis by single-underline included, emphasis by double-underline added).

Q. Would you summarize your findings with respect to the existence of undiscovered reserves?

A. Yes. In summary, historical annual new reserve discoveries show that significant upward adjustments to the discovered reserve base are occurring regularly; a significant amount of exploratory drilling is continuing to occur in Trailblazer's supply area; and an independent source has estimated a significant amount of undiscovered gas remaining in Trailblazer's supply area. These facts support the existence of as yet undiscovered or unproven reserves and support my estimate of the supply life for Trailblazer's supply area.

While natural gas is a finite resource, there is still a significant amount estimated to be discovered, and I believe there will be enough gas to keep Trailblazer operating for at least the next 35 years.

(6) Discussing Demand and Competition, and Determining the Remaining Economic Life

Q. Why is demand considered in your analysis?

A. Factors other than supply can affect the remaining economic life of a pipeline. While if there is no supply to transport, there is no business, it is also true that if there is no demand for the gas, there is likewise no business. A falling demand for gas could have a negative effect upon the future life of a facility.

Q. What are your findings regarding the effect of demand on the future life of Trailblazer's facilities?

A. I determined that demand will not have a negative effect on the supply life, and therefore, on the remaining economic life of Trailblazer's facilities. DRI-WEFA, Inc., in its U.S. Energy Outlook, Spring-Summer 2001, shows that it expects natural gas consumption to grow, rather than fall, in the future--in the areas that include the destinations of Trailblazer's throughput. In the East North Central Region, gas consumption is expected to grow from 3,837 trillion Btu (TBtu) in 1999 to 5,278 TBtu in 2020; and nationally, from 22,284 TBtu in 1999 to 32,498 TBtu in 2020 (Exhibit No. S-11, Schedule No. 14). The EIA also projects national gas demand to grow in the future, from 24.07 quadrillion Btu (QBtu) in 2000, to 35.81 QBtu in 2025 (Exhibit No. S-11, Schedule No. 15).

With demand projected to increase, it can be assumed that demand will not negatively impact the remaining economic life of Trailblazer's facilities.

Q. Will you discuss competition with respect to Trailblazer?

A. Yes. I believe it is premature to shorten Trailblazer's remaining economic life for the speculative effects of future competition. Competition is not synonymous with going out of business. The Commission wants a competitive environment, the purpose of which is to provide a natural check on transportation rates, not to drive a pipeline out of business.

Also, according to the Company's response to Staff Data Request (KJP-1), Item No. 17, which I have included as Exhibit No. S-11, Schedule No. 16, Trailblazer has 125 firm shipper contracts. These contracts have expiration dates ranging from 2003 to 2012, all the way to 2053 for a winter only agreement with Concord Energy, L.L.C. Further, thirteen of these contracts have been renewed in the past and may be renewed again when the time comes. Firm contracts show the customer base and established service that are advantages for Trailblazer over potential competitors.

Trailblazer also has an advantage over pipeline projects, if they are built. All other things being equal, a project would be a more expensive was to transport gas because the project would have to recover 100 percent of its investment; Trailblazer has already recovered about 63 percent of its Existing Facilities and Expansion Facilities transmission investment, meaning it only has about 37 percent of its investment left to recover.

Q. What do you conclude with respect to the remaining economic life of Trailblazer's system?

A. I conclude that with the supply life I calculated, with the demand projections as given above, and considering my discussion of competition, that supply life will not be shortened by demand or competition, and therefore, the supply life will equal the remaining economic life for Trailblazer's transmission facilities, which, as stated previously, is 35 years.

(7) Adjusting the Remaining Economic Life for Interim Retirements

Q. What are interim retirements?

A. Interim retirements are those retirements which occur before the end of the remaining economic life and the exhaustion of supply. Some examples of occurrences that can cause interim retirements include physical forces such as wear and tear, and action of the elements, which could reduce the ability of some of the facilities to remain in service over the entire remaining economic life of the facilities as a whole.

In determining the depreciation rates for Trailblazer's transmission facilities, I used a remaining economic life of 35 years (from December 31, 2001) as the maximum life-span, and adjusted this remaining economic life for early (interim) retirements.

Q. Why did you account for interim retirements?

A. The depreciation rate is applied to the gross plant to determine the annual expense. If, over time, the gross plant is reduced because of interim retirements, the annual expense will also be reduced. If interim retirements were not accounted for, the gross plant would not be fully recovered at the end of its remaining economic life.

Q. How did you account for interim retirements?

A. I accounted for interim retirements of Trailblazer's transmission facilities by the use of a statistical analysis of historical retirement patterns. Specifically, I employed Iowa-Type Survivor Curves (Iowa curves). With an Iowa curve and an estimated average age of the facilities, along with the remaining economic life, I determined an average remaining life (ARL) of all plant (both that which would be retired early and that which would not be retired until the end of the remaining economic life). This ARL accounts for interim retirements, and is naturally shorter than the remaining economic life of the facilities as a whole of 35 years. It is the ARL–average remaining life, rather than the remaining economic life of 35 years, that goes into the equation for calculating depreciation rates. This is to compensate for interim retirements decreasing the gross plant to which the depreciation rate is applied, so that the full investment will be recovered at the end of the 35-year period.

Q. Could you explain how Iowa curves are used in estimating the ARL of Trailblazer's facilities?

A. Iowa curves demonstrate the survivor characteristics of property from installation to retirement of the last unit. They are used to project how property will be retired in the future. The curves are defined by a survivor pattern and an average service life (ASL). The survivor pattern can also be thought of as a retirement pattern as they are the inverse of each other. The ASL is the average of how long all the facilities of a group are expected to last when they are new. The ARL is the average of how long the facilities of a group are expected to last when they are not new. The ASL, and the survivor/retirement pattern uniquely identify the Iowa curve. From this curve, the ARL is determined.

Exhibit No. S-11, Schedule No. 17, contains an explanation of Iowa curves as well as an example of an Iowa curve.

The more retirement experience there is regarding a particular class of plant, the more confidence one can have in the Iowa curve selection. However, when economic considerations cause a concurrent retirement of all units, the curve selection becomes less critical. This concurrent retirement results in the Iowa curve being truncated. This truncation occurs at the end of the remaining economic life. As used above, an economic consideration is one that causes retirement of the facility before it would be retired due to non-economic factors such as wear-and-tear. For Trailblazer, I believe that a lack of supply will end the life of the Company's facilities before non-economic factors would force it to cease operations.

Q. **What accounts did you use to represent the transmission function?**

A. Often, the interim retirement adjustment is done for the transmission function as a whole. For the Existing Facilities, I performed separate interim retirement adjustments on Compressor Station Equipment (Account No. 368), and on all plant except Compressor Station Equipment to arrive at a composite adjustment for the transmission function. Of this other transmission plant, Mains (Account No. 367) and Rights-of-Way (Account No. 365)--which is directly associated with Mains--account for over 97 percent of Trailblazer's non-Compressor Station Equipment transmission investment, based on plant balances as of December 31, 2002. I used a curve commonly used for these accounts to represent all of Trailblazer's non-Compressor Station Equipment transmission plant.

Q. What Iowa curves did you use for Trailblazer's plant?

A. I used an Iowa curve designated as 65 R2 for the Mains and Rights-of-Way accounts. The number 65 refers to the ASL in years and the designation R2 refers to a particular retirement pattern/curve. The 65 R2 curve is commonly used for transmission plant. I used an Iowa curve designated as 30 R3 for the compressor station account of the Existing Facilities and for the Expansion Facilities, which are compression station equipment. This curve takes into account the shorter expected life-span of equipment in this account as compared to the equipment in the Mains account.

Q. What is the ARL that you calculated using the above Iowa curves?

A. The ARL for a particular plant account is dependent on the age of the plant, as well as on the Iowa curve selected. For the Existing Facilities, factoring in this information and weighting the results arrives at an ARL of 30.1 years, as of December 31, 2002. This is shown in Exhibit No. S-11, Schedule No. 18. Also in this schedule, I have included the percent of plant surviving at truncation, which is 66.74 percent for the Existing Facilities as of December 31, 2002. This is the amount of existing plant, predicted by the Iowa curves, that will still be in service at the end of the remaining economic life of 35 years from December 31, 2001, or as of the end of 2036, at the point where the Iowa curve is truncated. The ARL and this latter information was given to Staff witness Taylor for his use in determining the proper negative net salvage rate(s) for Trailblazer's facilities.

Q. Did the Expansion Facilities have the same ARL as the Existing Facilities?

A. No. The Expansion Facilities consist of compressor station equipment. Therefore, only the 30 R3 Iowa curve was used, rather than both the 65 R2 and 30 R3 curves. Further, the average age of the Expansion Facilities is quite a bit less than the average age of the Existing Facilities. These factors led to an ARL for the Expansion Facilities of 28.1 years, and the percent surviving at truncation of 31.98 percent, both at December 31, 2002. These results are also shown on Exhibit No. S-11, Schedule No. 18.

To arrive at the ARL for the plant at March 31, 2003, which is the latest plant data available to Staff at the time of this testimony, I conservatively subtracted 0.25 years to account for the quarter year between my study date of December 31, 2002, and March 31, 2003. This can be seen by comparing the ARL's in Exhibit No. S-11, Schedule No. 18, with the ARL's shown in Exhibit No. S-11, Schedule No. 19, which is a schedule of factors in the depreciation calculation.

(8) Calculating the Depreciation Rates

Q. How did you calculate the depreciation rate for Trailblazer's transmission facilities?

A. The calculation of the depreciation rate is straightforward. It is calculated by dividing the ARL into the percent of the gross plant left to be depreciated. The gross plant left to be depreciated is also called the net plant. The net plant is the result of subtracting the accrued depreciation from the gross plant. Accrued depreciation and gross plant data were provided to me by Staff witness Segal. My depreciation calculation resulted in a rate of 0.90 percent for the Existing Facilities, 3.40 percent for the Expansion Facilities, and a rate of 1.25 percent should the Expansion Facilities be rolled into the Existing Facilities. Factors in the depreciation rate calculation appear in Exhibit No. S-11, Schedule No. 19. This schedule also shows the difference in annual expense amounts from my proposed depreciation rate versus Trailblazer's proposed depreciation rates based on the gross plant amounts provided by Staff witness Segal.

III. STAFF'S DEPRECIATION ANALYSIS FOR GENERAL PLANT

Q. What depreciation rate is Trailblazer proposing for its general plant?

A. Trailblazer depreciates its general plant on a functional basis. Its existing rate is 3.60 percent; Trailblazer is proposing to increase this rate to 10.00 percent.

Q. Do you agree with his recommendation with respect to General Plant?

A. No, according to my analysis, his rate should be increased to 20.00 percent from his recommended rate of 10.00 percent and the existing rate of 3.6 percent. This results in a small increase in annual expense of about $17,000 versus Mr. Simmons' proposed rate.

Q. Upon what is your proposed general plant depreciation rate based?

A. I used an average service life (ASL) approach to determine the depreciation rate. The expected ASL's of the various types of plant in each account were combined on a weighted average basis; that result was then used to calculate the depreciation rate.

Q. What is the ASL approach and why did you choose this approach rather than the ARL approach you used for calculating the transmission plant depreciation rate?

A. The depreciation rate in the ARL method is derived from the remaining economic life and the percentage of the plant left to be recovered. In shorter-lived accounts, such as Trailblazer's general plant accounts, plant is retired and replaced on an ongoing basis, sometimes several times before the remaining economic life of the Company as a whole is reached. Because of the relatively rapid turnover of plant in these accounts, the age of the plant (and therefore, its expected remaining life) and the percent of the plant left to recover (which shifts due to additions and retirements) can change dramatically from year to year. This would lead a ARL-based depreciation rate to also change from year to year.

In contrast, the varying of the remaining lives and the percent of the plant left to recover would not affect an ASL-based depreciation rate. The ASL method is often used for continuing property accounts made up of shorter-lived assets. An ASL-based depreciation rate is calculated from the ASL of the plant in question, regardless of the estimated remaining life of the plant, and regardless of the percent of the plant left to recover.

Q. How did you determine the average service lives for the various general plant accounts?

A. In response to Staff Data Request (KJP-1), Item No. 4, included as Exhibit No. S-11, Schedule No. 20, Trailblazer provided a brief description of items in these general plant accounts. Based on this information, my experience, and average service lives used in other proceedings, I determined an ASL for each account. From that point, I calculated a weighted-average ASL, based on the gross plant balances as of December 31, 2002. The depreciation rate falls out directly from the weighted-average ASL, namely 100 percent divided by the weighted-average service life. This calculation results in a rate of 19.92 percent, which I rounded to 20.00 percent. The gross plant, ASL, and a list of plant items by account are included in Exhibit No. S-11, Schedule No. 21. I have also included in this schedule the weighted-average ASL and the depreciation rate.

IV. SUMMARY OF STAFF'S DEPRECIATION ANALYSIS

Q. Mr. Pewterbaugh, would you please summarize your testimony with respect to your depreciation analysis?

A. Yes. I have provided analyses supporting a remaining economic life of 35 years from December 31, 2001, for Trailblazer's transmission plant. I have based my analysis of the transmission facilities on the gas reserves, resources, and production from the Colorado-Wyoming area. I have also considered demand for natural gas and potential competition in relation to this remaining economic life. I made an adjustment to account for interim retirements, and based on my analyses, calculated a depreciation rate of 0.90 percent for Trailblazer's Existing Facilities transmission plant, 3.40 percent for its Expansion Facilities, and 1.25 percent should the Expansion Facilities be rolled in with the Existing Facilities.

For general plant, I determined an ASL for each account, and derived a depreciation rate of 20.00 percent based on that information. Finally, I accepted Trailblazer's proposal for the amortization of its intangible account of 0.00 percent.

PART B--DISCUSSION OF THE TESTIMONY OF MR. SIMMONS

Q. How does Trailblazer attempt to support its depreciation rate proposals?

A. Trailblazer witness Geoffrey E. Simmons testifies to the depreciation calculations while Trailblazer witness Ronald Harrell testifies to the gas supply underlying the depreciation calculations.

Q. Please summarize the testimony of Mr. Simmons.

A. Mr. Simmons uses two approaches to support his changes in the transmission depreciation rates from 3.60 percent to 2.90 percent for the Existing Facilities, and from 5.00 to 7.00 percent for the Expansion Facilities. The first approach is a Unit-Of-Production (UOP) approach, which he terms as a Production Reserve Ratio analysis; the second approach he calls an Average Remaining Life of Gas Supply Study. Let me state that Mr. Simmons applies these two methods to the Eastern Rockies supply area and to the Northern Rockies supply area, which is a larger area encompassing the Eastern Rockies. His methodology is the same for each area. I have included examples using the Eastern Rockies as illustrative of the problems I have found in his approach.

Q. Do you agree with his methods or results?

A. No, I have found that his methods are incorrect and he has arrived at depreciation rates that are too high.

Q. Would you proceed with your analysis of Mr. Simmons' Production Reserve Ratio analysis?

A. Yes, there are two faults that I want to address with his approach. Let me first describe the UOP approach. The Commission has used either a straight-line approach or a UOP approach in determining depreciation rates for interstate gas pipeline companies. The straight-line approach allocates depreciation evenly over the life of the asset in terms of the length of time the asset will be in service; the UOP approach allocates depreciation evenly over the life of the asset in terms of the total units of throughput that the asset will transport over its life. As I cited earlier from the Memphis decision, "In order to be 'just and adequate' a reserve life depreciation rate must be based upon the useful life of the particular property involved." Using production and total reserves as proxies for annual throughput on the pipeline and the total throughput over its remaining life (the useful life in terms of throughput), Mr. Simmons did not divide the production in a given year by the total amount of reserves that the pipeline will transport over its remaining life, rather, he divided the production by only a portion of the total reserves. This results in a depreciation rate that is higher than it should be, leading to current ratepayers paying more than their share with respect to later ratepayers, in effect subsidizing the later ratepayers.

Mr. Simmons only uses the remaining reserves, which he calls the Supply Base, and the current year's reserve additions (Exhibit No. TPC-55, page 12, lines 17 through 20), rather than the total gas supply that he should have used.

Q. **Mr. Simmons used a 20-year period for deliveries in his depreciation calculation (Exhibit No. TPC-55, page 11, lines 16 through 23). Do you agree with this time period?**

A. No, a 20-year time period will not capture all of the future reserve additions if the pipeline is expected to still be in service beyond that time, as my analysis shows. All of the future gas that will be transported through the pipeline should be used in determining a proper UOP depreciation rate. The Staff has estimated certain pipelines to be in service beyond 20 years, and the Commission has approved remaining lives longer than 20 years, for example, in Iroquois Gas Transmission System, L.P., 84 FERC ¶ 61,086 (1998), the Commission approved a 35-year remaining life. Also supporting a 35-year remaining life is the Commission's order in Enbridge Pipelines (KPC), 100 FERC ¶ 61,260 (2002).

Q. **Have you performed any calculations to show the effects of Mr. Simmons' misapplication of the production reserve ratio?**

A. Yes. I have replicated his Exhibit No. TPC-56, Schedule Nos. B and C, which are the tables upon which he calculates the depreciation rates for the Eastern Rockies area. In my reworking of this schedule, I have changed only his treatment of reserves, I have not changed the total reserves he uses to what the total reserves should actually be. With only that one change, dividing production by total supply, rather than by only an increment of total supply, the average depreciation rate for the first six years changes from 3.06 percent to 1.87 percent. This is a significant difference. This is shown in Exhibit No. S-11, Schedule No. 22. The first two pages of this schedule show his original tables; the second two pages show the results of making just that one change.

Q. **Mr. Simmons makes the statement that "Trailblazer along with potential future shippers should not be burdened at this juncture to the benefit of existing shippers by a <u>deflated</u> depreciation rate that might be set to encompass an <u>extended</u> time period." (Exhibit No. TPC-55, page 12, lines 9 through 11) Would you comment on this assertion? (Emphasis added)**

A. Yes. Dealing with shippers first, the purpose of the depreciation rate is to allocate the recovery of investment in a fair manner to all generations of shippers. The reverse of Mr. Simmons' statement must also be considered, namely, existing shippers should not be burdened to the benefit of potential future shippers by an <u>inflated</u> depreciation rate that might be set to encompass a <u>shortened</u> time period. In other words, if the present rate is set too high, that would lead to Trailblazer's investment being recovered too quickly, with the result that later ratepayers would in effect pay a rate that was subsidized by current shippers. With respect to Trailblazer, if the investment is recovered too quickly, the result is a rate base in the future that is lower than it should be. The purpose of depreciation is to ensure the recovery of the pipeline's investment; it is not to hasten that recovery for the company's cash flow needs. The question is not whether Trailblazer and its customers will be burdened with costs in the future (see Exhibit No. TPC-55, page 17, lines 4-8; page 18, lines 13 through 16)--they should have a cost burden until the end of the remaining life of the pipeline--the question is whether Trailblazer and its customers will be unfairly burdened. If the inflated depreciation rate proposal of Trailblazer were to be accepted, then the answer would be that current ratepayers would be unfairly burdened with costs, while Trailblazer would in effect pre-collect some of its investment at the expense of its future rate base. This scenario carried too far would result in the Company having no rate base, and therefore no rate of return, while still being in business, and its future shippers would bear no portion of the burden of the recovery of the pipeline's investment.

Q. **If Mr. Simmons used a UOP approach in his depreciation calculation, why didn't you use that approach as well?**

A. Generally speaking, the Commission Staff has limited its application of the UOP method to the offshore area or to where the pipeline's supply is from a limited supply area, such as a specific field. The Eastern Rockies area is not considered a limited supply area in this context.

But the problem with the UOP method, apart from the Staff's application of it, is that the straight-line depreciation rate derived from the UOP method, even if it is the appropriate rate, is only appropriate for a limited amount of time. As can be interpreted from Mr. Simmons' Exhibit No. TPC-56, the UOP method produces a different depreciation rate each year. These results are then averaged over a certain number of years (six years for the Existing Facilities in this case) to arrive at a single depreciation rate to be applied to Trailblazer's plant over that time period. Once that time period is over, even if nothing else changes about the Company, that rate would no longer be appropriate--built as it was on an average of a few years rather than on the entire remaining life of the Company. A review of the rate should be undertaken at that point. This is in contrast to the straight-line method I used to derive the proper depreciation rate, where if nothing else changes about the Company, the rate would still be appropriate. And it would continue to be appropriate to the end of the remaining life of the Company. Even if both a UOP-derived rate and a straight-line method-derived rate both started out correct, the UOP-derived rate would cease to be correct once the period of time over which it was averaged was over.

The automatic divergence over time of the UOP-derived rate from the correct depreciation rate is a problem because there is no longer an automatic review process at the Commission. Even if a section 5 proceeding were initiated at the point where the average rate was no longer appropriate, because the rates would be prospective, it may be two years or more before this obsolete depreciation rate would be corrected. If this obsolete rate were allowed to continue long enough, the result would be the recovery of Trailblazer's investment before its remaining life was over, meaning Trailblazer would continue operations without any rate base, and that future ratepayers at that time would unfairly not be responsible for the recovery of any of the pipeline's capital investment; rather, they will pay a rate subsidized by earlier ratepayers.

In contrast, a depreciation rate calculation using the straight-line method would not have to be revisited just because a certain length of time had passed, because it is not based on averaging constantly changing rates over a specific number of years. Assuming there were no significant changes to Trailblazer's operations, the depreciation rate based on the straight-line approach would be applicable over the entire remaining life of the pipeline, while a UOP-derived rate would not.

Q. Mr. Simmons states that given certain uncertainties, his approach, of a higher present depreciation rate, "equitably allocates the depreciation burden between existing and future customers." (Exhibit No. TPC-55, page 19, lines 10 through 12) Do you agree?

A. No, I do not agree. He states that "Trailblazer acts as an intermediary, with limited direct access to either production or markets" (Exhibit No. TPC-55, page 18, lines 20 and 21). He then concludes that "no such reserves can be expected to flow on Trailblazer absent renewed, extended or new transportation agreements" (Exhibit No. TPC-55, page 18, line 23 through page 19, line 1). Of course that is the case, but one should not infer that renewing transportation agreements is an impossible task--gas transmission is Trailblazer's business. Current ratepayers should not be penalized by having to bear a disproportionate part of the recovery of Trailblazer's investment because Trailblazer is involved in a competitive business.

Mr. Simmons mentions other factors discussed by Trailblazer witness Ronald L. Brown (Exhibit No. TPC-55, page 19, lines 4 through 10). These factors are new projects creating more competition for the Rocky Mountain supply, the Chicago market becoming served by Alaska and other arctic sources, and the growth of gas consumption in the Rocky Mountain area. However, as stated previously, competition is not synonymous with going out of business. I believe it is too speculative to limit Trailblazer's remaining life on these uncertainties, as Mr. Simmons calls them.

Q. Would you now proceed with your analysis of Mr. Simmons' Average Remaining Life of Gas Supply Study?

A. Yes. To arrive at his estimate of Average Remaining Life, which I will designate as ARL-prime to distinguish it from the Average Remaining Life as used earlier in my analysis, Mr. Simmons weights the amount of the future deliveries by the number of years that the gas will remain in the ground until it is delivered. Obviously, the number of years he includes in his analysis is significant. For example, if he projected only five years into the future, the ARL-prime as shown in Exhibit No. TPC-56, Schedule F, page 1 of 2, column 4, would be 2.47 years rather than the 8.84 years he shows, and the depreciation rate would be correspondingly higher. He used 20 years in his analysis which essentially guarantees an ARL-prime of less than 20 years--and basically, because it's an average, of something around ten years. From this one point alone, he will get a shorter ARL-prime, and consequently, a larger depreciation rate.

Q. How is Mr. Simmons' ARL approach different from the ARL approach you used?

A. My ARL is determined from the entire remaining life of the pipeline, and from the expected retirements to the gross plant over that time. In contrast, Mr. Simmons' ARL (ARL-prime) is an average based on the pipeline's throughput. His approach is not the same as the straight-line depreciation approach the Staff normally employs.

Q. What is the significance of the fact that the Production Reserve Ratio rate and the ARL rate he determined turned out to be similar?

A. I do not believe any significance should be attached to Mr. Simmons' result. As I have shown, his Production Reserve Ratio method was done incorrectly, and the ARL-Prime approach is controlled by the number of years over which the average is taken.

Q. Do you agree that interim retirements should be included in the depreciation calculations?

A. Yes, and I have included them as discussed earlier by my use of the Iowa curves.

PART C--DISCUSSION OF THE TESTIMONY OF MR. HARRELL

Q. What were Mr. Harrell's responsibilities in this proceeding?

A. Mr. Harrell supports the future supply of gas in Trailblazer's supply areas. He also makes certain assertions with which I disagree.

Q. Would you proceed with your analysis?

A. Yes, in Exhibit No. TPC-59, page 8, lines 1 through 8, he states that an extrapolation of area-wide data "cannot be relied upon as the basis of a projection of production from developed reserves." This point, however, needs to examined in the context of this proceeding, namely the determination of the proper depreciation rate for an interstate natural gas transmission company. In this context, the entire supply of a broad area is used as a proxy for the specific portion of that supply that will actually flow through the pipeline, remembering that pipeline companies are no longer the owners of the gas, just the transporters, so their gas supply is less specific and can change over time. The goal is to determine the total supply available for a pipeline, not the economic viability of a particular exploration project. This area-wide approach has been used in numerous cases, and the Commission has recognized this approach, for example, in its order in Trunkline Gas Company, Docket No. RP96-129-000, in which it stated,

> The Commission's depreciation decisions are made in the context of gas ratemaking proceedings. They consider the foreseeable future of the pipeline and its supply areas and must be based on

long-term forecasts of supply over large areas. (90 FERC ¶ 61,017 (slip op. at 17)).

Q. Please continue.

A. Mr. Harrell states that "Any number of influences including drilling of additional wells, recompletions of existing wells, varied declines in productivity, reservoir stimulation, market fluctuations and other factors can affect the production rates from year to year in an inconsistent and non-repeatable fashion" and that the "Production rate from a representative group of wells will typically result in a decline trend that can be extrapolated with a high level of confidence." (Exhibit No. TPC-59, page 8, lines 8 through 13).

With respect to Mr. Harrell's assertion that any number of influences can affect production rates, these influences should be accounted for because they will impact the supply available to the pipeline. Typically, there <u>will</u> be additional drilling in Trailblazer's supply area, there <u>will</u> be recompletions, there <u>will</u> be market influences--I expect market influences to lead to additional gas being added to the supply--these and other factors should not be excluded. Not accounting for these factors could result in an understated supply projection. My area-wide supply analysis includes the effect of these factors by extrapolating historical data which contains them. Further, the effect of any truly unusual data is mitigated by the least squares extrapolations I have used.

With respect to his statement that the "Production rate from a representative group of wells will typically result in a decline trend that can be extrapolated with a high level of confidence", one concern with using a purported representative group of wells is the possibility that legitimate factors could be excluded from the group, resulting in an understated extrapolation.

Contrary to Mr. Harrell's assertion, area-wide data can be used with confidence and does provide reliable trends. Again, the goal is to determine the total supply available for a pipeline, not the economic viability of a particular exploration project.

Q. **Mr. Harrell spends a good deal of time trying to support the idea that resource values from the PGC need to be adjusted downward to account for risk? Do you agree with his assertion?**

A. No. This issue has already been determined by the Commission in its order in Trunkline Gas Company, Docket No. RP96-129-000, issued on January 12, 2000 (90 FERC ¶ 61,017).

Q. **Who was the Commission Staff's depreciation witness in the Trunkline proceeding?**

A. I was the Commission Staff's witness for depreciation in that proceeding.

Q. **In the Trunkline proceeding, how did you rebut the assertion that risk was not accounted for?**

A. I showed that the PGC does adjust for the risk that gas may not be found in a particular area, using quotes from its own documents; for example, according to the PGC's 1994

Report entitled, Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee (December 31, 1994) (PGC Report). On page 2 of this report the PGC states:

> The estimates of the Potential Gas Committee (PGC) represent potential natural gas resources expected to be recovered by future drilling under conditions of:
>
> 1. adequate economic incentives in terms of price/cost relationships, and
> 2. current or foreseeable technology.
>
> (emphasis added)

The term "expected to be recovered" connotes that reserves expected not to be recovered are not included. This was supported by Dr. Curtis, a Company witness, in response to a Staff data request in the Trunkline proceeding, wherein he stated that "The PGC does not estimate 'unrecoverable resources'". Other statements from the PGC that support my interpretation include:

> The Committee...has since that time prepared regular reports of estimates of the recoverable natural gas that is believed to exist in addition to proved reserves. (page iii)
>
> (emphasis added)

> The estimates of the Potential Gas Committee (PGC) are of natural gas that, in the judgment of its members, can be recovered by conventional means.... (page 3)
>
> (emphasis added)

> The basic technique for estimating potential gas resources is to compare the factors that control known occurrences with factors present in prospective areas. (page 7)
>
> ...the estimate of the potential gas supply is derived by ...(3) discounting to allow for the probability that traps and/or accumulations exist. (page 9)
>
> (emphasis added)
>
> Each estimator considers three separate situations in preparing estimates: ...(2) The most reasonable estimate of the existence of traps and accumulations.... (page 9)
>
> (emphasis added)
>
> The recoverable resource then is that part of the total resource that is susceptible to discovery and production during the life of the industry using current or foreseeable technology and under favorable price/cost ratios. (page 5)
>
> (emphasis added)
>
> ...a minimum size of recoverable accumulation is determined on the basis of the estimator's judgment of the current relationship between the value of the resource and the costs of drilling and production. (page 5)
>
> (emphasis added)
>
> Economic, technological and governmental policy factors taken into account in the PGC's gas estimates are related to...(2) all wells that would be drilled in the future.... (page 10)

These statements show that the PGC makes estimates of the natural gas it believes is recoverable. The PGC does not include gas it deems unrecoverable. Also, the PGC does not consider 100 percent of the favorable geologic characteristics as containing recoverable gas. The PGC accounts for the possibility that some of the geologic locations will not contain recoverable gas, as seen by the statements containing "discounting", "probability", and "minimum size".

Q. Has the PGC changed its analyses or views since the time that Dr. Curtis submitted testimony in Trunkline?

A. No. Mr. Harrell spoke to Dr. Curtis subsequent to the Trunkline proceeding. According to Mr. Harrell (in discussing Dr. Curtis' Trunkline testimony), Dr. Curtis "maintained that the facts and opinions he expressed in his testimony are still valid." (Exhibit No. TPC-59, page 18, lines 11 and 12).

Q. You said that the Commission has ruled in the Trunkline proceeding. Will you summarize the Commission's conclusions with respect to downgrading estimates to account for risk?

A. Yes. The Trunkline order states that:

> The Commission finds that Trunkline misapprehends both the context in which the estimates are being used and the PGC estimates themselves. The Commission's depreciation decisions are made in the context of gas ratemaking proceedings. They consider the foreseeable future of the pipeline and its supply areas and must be based on long-term forecasts of supply over large areas. They are based on the resources available within whole gas supply provinces. The full universe of available supplies must be considered in determining the remaining life of the pipeline as an active operation and its corresponding depreciation rates.
>
> While Trunkline's witnesses alluded to academic and industry standards that they claimed required reductions of the PGC estimates (e.g., Tr. at 482 and 486), they introduced very little of such material and the little they produced does not support their

> position. Trunkline relies on a chapter of a textbook, R.E. Megill, An Introduction to Exploration Economics, pp. 110-128 (2d ed.)(Pennwell Books, Tulsa, Oklahoma). Examination of the portion cited shows that the intended audience is persons or companies evaluating exploratory investments, that is, exploratory wells. This text applies to specific efforts by investors to drill for gas in precise locations, or as the ALJ said, it applies where a particular property is being evaluated. It does not address gas ratemaking before a federal agency nor does it apply to the broad areas under consideration in determining the pipeline's depreciation rates. It is thus inapplicable here. (cite and footnotes omitted).
>
> Trunkline also objects that the PGC estimates include gas that will not be discovered and produced. But the Commission finds that the PGC estimates Staff has used take these matters into account in a manner sufficient for the purpose of determining depreciation rates in this rate proceeding. (90 FERC ¶ 61,017 at 61,055-56).

The Commission concluded:

> For the reasons discussed above, the Commission finds that, for gas ratemaking purposes, the PGC estimates adequately take into consideration whether gas will be produced and limiting potential supplies to probable and possible PGC categories and, further, to the most likely estimates for those categories, produces estimates of supplies that it is reasonable to expect will be discovered over the remaining life of the pipeline. The latter conclusion is bolstered by Staff's observation that the estimates may understate resources and that the estimates of most likely probable and possible resources in Trunkline's supply areas have been increasing. (cite and footnote omitted) (90 FERC ¶ 61,017 at 61,057).

Q. What do you conclude about the testimony of Mr. Simmons and Mr. Harrell?

A. I conclude that Mr. Simmons' UOP and ARL methods are incorrect and that his depreciation proposals should not be accepted. I conclude that Mr. Simmons used Mr.

Harrell's data incorrectly, and further, that Mr. Harrell's assertion that gas supplies need to be discounted to account for risk is inappropriate in the context of a gas pipeline rate proceeding, as has already been determined by the Commission.

Q. Mr. Pewterbaugh, does this conclude your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Trailblazer Pipeline Company) Docket No. RP03-162-000

I, Kevin J. Pewterbaugh, do hereby declare under penalty of perjury that I am the author of the foregoing testimony, that the facts set forth therein are true and correct to the best of my knowledge, and that if asked the questions contained in the text, I would give the answers contained in the testimony.

Kevin J. Pewterbaugh

Kevin J. Pewterbaugh

5-22-03

Date

EXHIBIT NO. S-11

FEDERAL ENERGY REGULATORY COMMISSION
OFFICE OF ADMINISTRATIVE LITIGATION

TRAILBLAZER PIPELINE COMPANY
DOCKET NO. RP03-162-000

EXHIBIT OF

COMMISSION STAFF WITNESS

KEVIN J. PEWTERBAUGH

ON

DEPRECIATION

MAY 22, 2003

WASHINGTON, D.C. 20426

Trailblazer Pipeline Company
Docket No. RP03-162-000

Trailblazer Pipeline Company
Docket No. RP03-162-000

Trailblazer Pipeline Company
Docket No. RP03-162-000
Rate Case Proceedings in which Kevin J. Pewterbaugh Submitted Testimony

Company	Docket No.
Eastern Shore Natural Gas Company	RP87-61-000
Chandeleur Pipe Line Company	RP88-120-000
Chandeleur Pipe Line Company	RP89-86-000
Kentucky West Virginia Gas Company	RP86-52-000 and RP86-109-000
National Fuel Gas Supply Corporation	RP89-49-000
Transcontinental Gas Pipe Line Corporation	RP90-8-000
MIGC, Inc.	RP90-86-000
Southern Natural Gas Company	RP90-139-000, et al.
Columbia Gulf Transmission Company	RP90-107-000
Columbia Gulf Transmission Company	RP91-160-000
Tennessee Gas Pipeline Company	RP91-203-000
Southern Natural Gas Company	RP92-134-000
Stingray Pipeline Company	RP91-212-000
Tennessee Gas Pipeline Company	RP91-203-000 and RP92-132-000
Southern Natural Gas Company	RP93-15-000, et al.
U-T Offshore System	RP93-61-000
High Island Offshore System	RP93-59-000
MIGC, Inc.	RP93-89-000
CNG Transmission Corporation	RP94-96-000
Northwest Pipeline Corporation	RP94-220-000
ANR Pipeline Company	RP94-43-000
Williams Natural Gas Company	RP95-136-000
Northern Natural Gas Company	RP95-185-000
Williston Basin Interstate Pipeline Company	RP95-364-000
Northwest Pipeline Corporation	RP95-409-000
Sea Robin Pipeline Company	RP95-167-000
Trunkline Gas Company	RP96-129-000
Columbia Gas Transmission Corporation	RP95-408-000
Mississippi River Transmission Corporation	RP96-199-000
Williams Natural Gas Company	RP96-173, et al.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Rate Case Proceedings in which Kevin J. Pewterbaugh Submitted Testimony

Company	Docket No.
Iroquois Gas Transmission System, L. P.	RP97-126-000
Columbia Gulf Transmission Company	RP97-52-000
Wyoming Interstate Company, Ltd.	RP97-375-000
Trailblazer Pipeline Company	RP97-408-000
Equitrans, L.P.	RP97-346-000
Exxon Company, U.S.A. v. Amerada Hess Pipeline Corporation, et al.	OR96-14-000
Northern Natural Gas Company	RP98-203-000
Northern Border Pipeline Company	RP99-322-000
Kansas Pipeline Company	RP99-485-000
Williston Basin Interstate Pipeline Company	RP00-107-000
Big West Oil Co. v. Frontier Pipeline Co., et al. Chevron Products Co. v. Frontier Pipeline Co., et al.	OR01-2-000, et al. OR01-4-000, et al. (Consolidated)
Big West Oil Co. v. Anschutz Ranch East Pipeline, Inc., et al. Chevron Products Co. v. Anschutz Ranch East Pipeline, Inc., et al.	OR01-2-000, et al. OR01-4-000, et al. (Consolidated)
Portland Natural Gas Transmission System	RP02-13-000

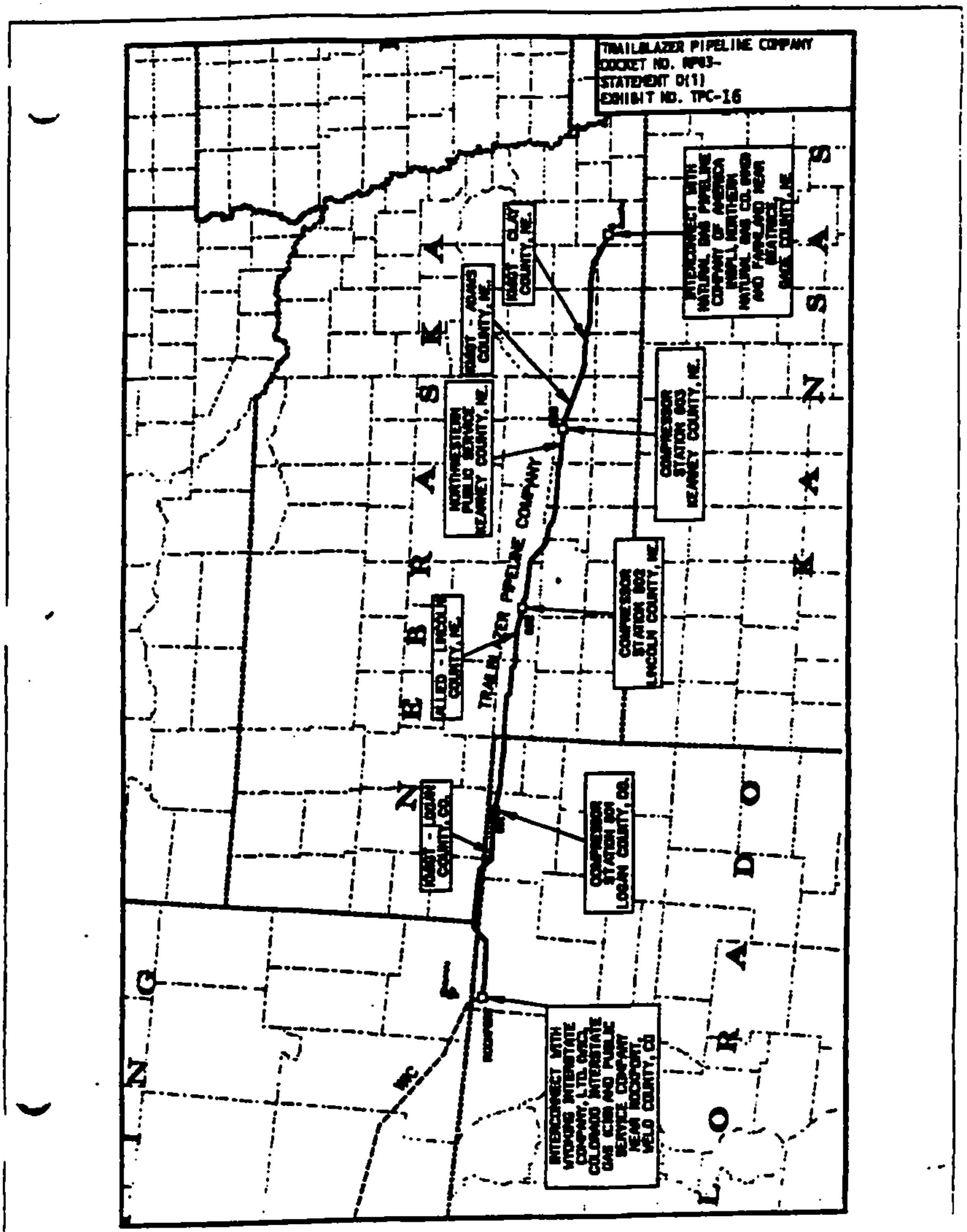
Trailblazer Pipeline Company
Docket No. RP03-162-000
Oil Company Depreciation Studies Performed by Kevin J. Pewterbaugh

Company	Study Date
Okie Pipe Line Company	May, 1982
Tomahawk Pipe Line Company	July, 1982
Enterprise Products Company of Mississippi	May, 1983
Dorchester Liquids Transportation Corp.	June, 1983
Enterprise Petrochemical Company	August, 1983
Enterprise Pipeline Company	October, 1983
Seminole Pipeline Company	January, 1984
Tomahawk Pipe Line Company	February, 1984
Cities Service NGL Pipeline Company	May, 1984
G & T Pipeline Company	July, 1984
National Transit Company	November, 1984
Sohio Pipe Line Company	April, 1985
Collins Pipeline Company	April, 1985
CKB Petroleum, Inc.	July, 1985
Allegheny Pipeline Company	July, 1985
Frontier Pipeline Company	March, 1986
The Largo Company	May, 1986
Mitco Pipeline Company	June, 1986
Atlantic Pipeline Corporation	July, 1986
Buccaneer Pipe Line Company	July, 1986
Coastal Pipeline Company	September, 1986
Owensboro-Ashland Company	January, 1987
Seminole Pipeline Company	October, 1987
Tecumseh Pipe Line Company	October, 1987
Yellowstone Pipe Line Company	October, 1987
Sonat Oil Transmission Inc.	September, 1988
Pioneer Pipe Line Company	March, 1988
Mid-Valley Pipeline Company	June, 1989
Northern Rockies Pipe Line Company	December, 1989
Olympic Pipe Line Company	August, 1990
Black Lake Pipe Line Company	August, 1991
Koch Pipelines, Inc.	August, 1991

Trailblazer Pipeline Company
Docket No. RP03-162-000
Summary of Results

Function	Gross Plant (3/31/03)	Depreciation Rates: Company Existing Rate	Company Proposed Rate	Staff Proposed Rate	Staff Percent Surviving at Truncation (12/31/02)
	($)	(%)	(%)	(%)	(%)
Existing Plant					
Intangible	90,746	33.30	0.00	0.00	--
Transmission	283,200,082	3.60	2.90	0.90	66.74
General	174,377	3.60	10.00	20.00	
Expansion Plant					
Transmission	47,109,741	5.00	7.00	3.40	31.98
Existing and Expansion					
Transmission	330,309,823	--	3.48 (calculated by Staff)	1.25	61.78

Trailblazer Pipeline Company
Docket No. RP03-162-000
Map of System



Trailblazer Pipeline Company
Docket No. RP03-162-000
The Straight-Line Depreciation Formula

The Depreciation formula is as follows:

DR = (DE ÷ GP) x 100, where

DR = Depreciation Rate

DE = Depreciation Expense, the amount to recover each year

GP = Gross Plant

The depreciation expense portion of the formula is derived as follows:

DE = NP ÷ ARL, where

NP = Net Plant, the amount left to recover

ARL = Average Remaining Life

The net plant portion of the formula is derived as follows:

NP = GP - (+/- NS) - AD

GP = Gross Plant

NS = Net Salvage (which can be either positive or negative)

AD = Accrued Depreciation

An equivalent depreciation formula is:

DR = ((NP ÷ GP) x 100) ÷ ARL, where

(NP ÷ GP) x 100 = percent of the gross plant left to be depreciated.

Trailblazer Pipiline Company
Docket No. RP03-162-000
Historical Annual Production and Remaining Reserve Data
(Dry Gas in Bcf)
(Colorado, Wyoming)

Year	Production	Remaining Reserves
1977	489	8,817
1978	496	9,976
1979	511	10,134
1980	579	12,022
1981	588	12,268
1982	587	13,072
1983	570	13,375
1984	655	13,425
1985	599	13,498
1986	590	12,783
1987	615	12,965
1988	698	13,843
1989	811	15,018
1990	812	14,499
1991	921	15,708
1992	1,034	17,024
1993	1,100	17,655
1994	1,227	17,632
1995	1,320	19,422
1996	1,322	20,030
1997	1,453	20,390
1998	1,514	21,531
1999	1,932	23,213
2000	1,829	26,586
2001	2,168	30,925

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Report (1977-2001)*, *Energy Information Administration.*

Trailblazer Pipiline Company
Docket No. RP03-162-000
Historical Ultimate Recovery Data
(Dry Gas in Bcf)
(Colorado, Wyoming)

Year	Cumulative Production	Remaining Reserves	Ultimate Recovery
1977	13,357	8,817	22,174
1978	13,853	9,976	23,829
1979	14,364	10,134	24,498
1980	14,943	12,022	26,965
1981	15,531	12,268	27,799
1982	16,118	13,072	29,190
1983	16,688	13,375	30,063
1984	17,343	13,425	30,768
1985	17,942	13,498	31,440
1986	18,532	12,783	31,315
1987	19,147	12,965	32,112
1988	19,845	13,843	33,688
1989	20,656	15,018	35,674
1990	21,468	14,499	35,967
1991	22,389	15,708	38,097
1992	23,423	17,024	40,447
1993	24,523	17,655	42,178
1994	25,750	17,632	43,382
1995	27,070	19,422	46,492
1996	28,392	20,030	48,422
1997	29,845	20,390	50,235
1998	31,359	21,531	52,890
1999	33,291	23,213	56,504
2000	35,120	26,586	61,706
2001	37,288	30,925	68,213

Sources: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Report (1977-2001)*, *Energy Information Administration.*

U.S. Oil and Gas Reserves, By Year of Field Discovery, *Energy Information Administration, 1990.*

Trailblazer Pipeline Company
Docket No. RP03-162-000
Corrected--Extrapolation of Ultimate Recovery
using an S-Curve Fit
Inflection Point equals 2001
(Colorado, Wyoming)

Est. Ultimate Recovery 115,000 R^2 = 0.95005

Change in Estimated Ult. Rec.	Estimated Ult. Rec.	Year	for graph: Ult. Rec. Actual	for graph: Ult. Rec. Estimated	Change in Actual Ult. Rec.	Year	Actual Ult. Rec. Percent	Estimated Ult. Rec. Percent	X	X^2	Ln(1/Y-1) Y	Y^2	X*Y
	708	1920		708		1920	0.00	0.006	-56	3,136.00			
45.97	754	1921		754		1921	0.00	0.007	-55	3,025.00			
48.93	803	1922		803		1922	0.00	0.007	-54	2,916.00			
52.08	855	1923		855		1923	0.00	0.007	-53	2,809.00			
55.43	910	1924		910		1924	0.00	0.008	-52	2,704.00			
59.00	969	1925		969		1925	0.00	0.008	-51	2,601.00			
62.79	1,032	1926		1,032		1926	0.00	0.009	-50	2,500.00			
66.81	1,099	1927		1,099		1927	0.00	0.010	-49	2,401.00			
71.09	1,170	1928		1,170		1928	0.00	0.010	-48	2,304.00			
75.64	1,246	1929		1,246		1929	0.00	0.011	-47	2,209.00			
80.47	1,326	1930		1,326		1930	0.00	0.012	-46	2,116.00			
85.61	1,412	1931		1,412		1931	0.00	0.012	-45	2,025.00			
91.06	1,503	1932		1,503		1932	0.00	0.013	-44	1,936.00			
96.85	1,600	1933		1,600		1933	0.00	0.014	-43	1,849.00			
103.00	1,703	1934		1,703		1934	0.00	0.015	-42	1,764.00			
109.53	1,812	1935		1,812		1935	0.00	0.016	-41	1,681.00			
116.45	1,929	1936		1,929		1936	0.00	0.017	-40	1,600.00			
123.80	2,053	1937		2,053		1937	0.00	0.018	-39	1,521.00			
131.59	2,184	1938		2,184		1938	0.00	0.019	-38	1,444.00			
139.85	2,324	1939		2,324		1939	0.00	0.020	-37	1,369.00			
148.61	2,473	1940		2,473		1940	0.00	0.022	-36	1,296.00			
157.89	2,631	1941		2,631		1941	0.00	0.023	-35	1,225.00			
167.72	2,798	1942		2,798		1942	0.00	0.024	-34	1,156.00			
178.13	2,976	1943		2,976		1943	0.00	0.026	-33	1,089.00			
189.15	3,166	1944		3,166		1944	0.00	0.028	-32	1,024.00			
200.81	3,366	1945		3,366		1945	0.00	0.029	-31	961.00			
213.14	3,579	1946		3,579		1946	0.00	0.031	-30	900.00			
226.18	3,806	1947		3,806		1947	0.00	0.033	-29	841.00			
239.95	4,046	1948		4,046		1948	0.00	0.035	-28	784.00			
254.50	4,300	1949		4,300		1949	0.00	0.037	-27	729.00			
269.85	4,570	1950		4,570		1950	0.00	0.040	-26	676.00			
286.04	4,856	1951		4,856		1951	0.00	0.042	-25	625.00			
303.11	5,159	1952		5,159		1952	0.00	0.045	-24	576.00			
321.08	5,480	1953		5,480		1953	0.00	0.048	-23	529.00			
340.01	5,820	1954		5,820		1954	0.00	0.051	-22	484.00			
359.91	6,180	1955		6,180		1955	0.00	0.054	-21	441.00			
380.83	6,561	1956		6,561		1956	0.00	0.057	-20	400.00			
402.80	6,964	1957		6,964		1957	0.00	0.061	-19	361.00			
425.84	7,390	1958		7,390		1958	0.00	0.064	-18	324.00			
449.99	7,840	1959		7,840		1959	0.00	0.068	-17	289.00			
475.28	8,315	1960		8,315		1960	0.00	0.072	-16	256.00			
501.72	8,817	1961		8,817		1961	0.00	0.077	-15	225.00			
529.34	9,346	1962		9,346		1962	0.00	0.081	-14	196.00			
558.16	9,904	1963		9,904		1963	0.00	0.086	-13	169.00			
588.18	10,492	1964		10,492		1964	0.00	0.091	-12	144.00			
619.42	11,112	1965		11,112		1965	0.00	0.097	-11	121.00			
651.87	11,764	1966		11,764		1966	0.00	0.102	-10	100.00			
685.53	12,449	1967		12,449		1967	0.00	0.108	-9	81.00			
720.39	13,169	1968		13,169		1968	0.00	0.115	-8	64.00			
756.41	13,926	1969		13,926		1969	0.00	0.121	-7	49.00			
793.58	14,719	1970		14,719		1970	0.00	0.128	-6	36.00			
831.85	15,551	1971		15,551		1971	0.00	0.135	-5	25.00			
871.16	16,422	1972		16,422		1972	0.00	0.143	-4	16.00			
911.45	17,334	1973		17,334		1973	0.00	0.151	-3	9.00			
952.65	18,287	1974		18,287		1974	0.00	0.159	-2	4.00			

Trailblazer Pipeline Company
Docket No. RP03-162-000
Corrected--Extrapolation of Ultimate Recovery
using an S-Curve Fit
Inflection Point equals 2001
(Colorado, Wyoming)

Est. Ultimate Recovery 115,000 R^2 = 0.95005

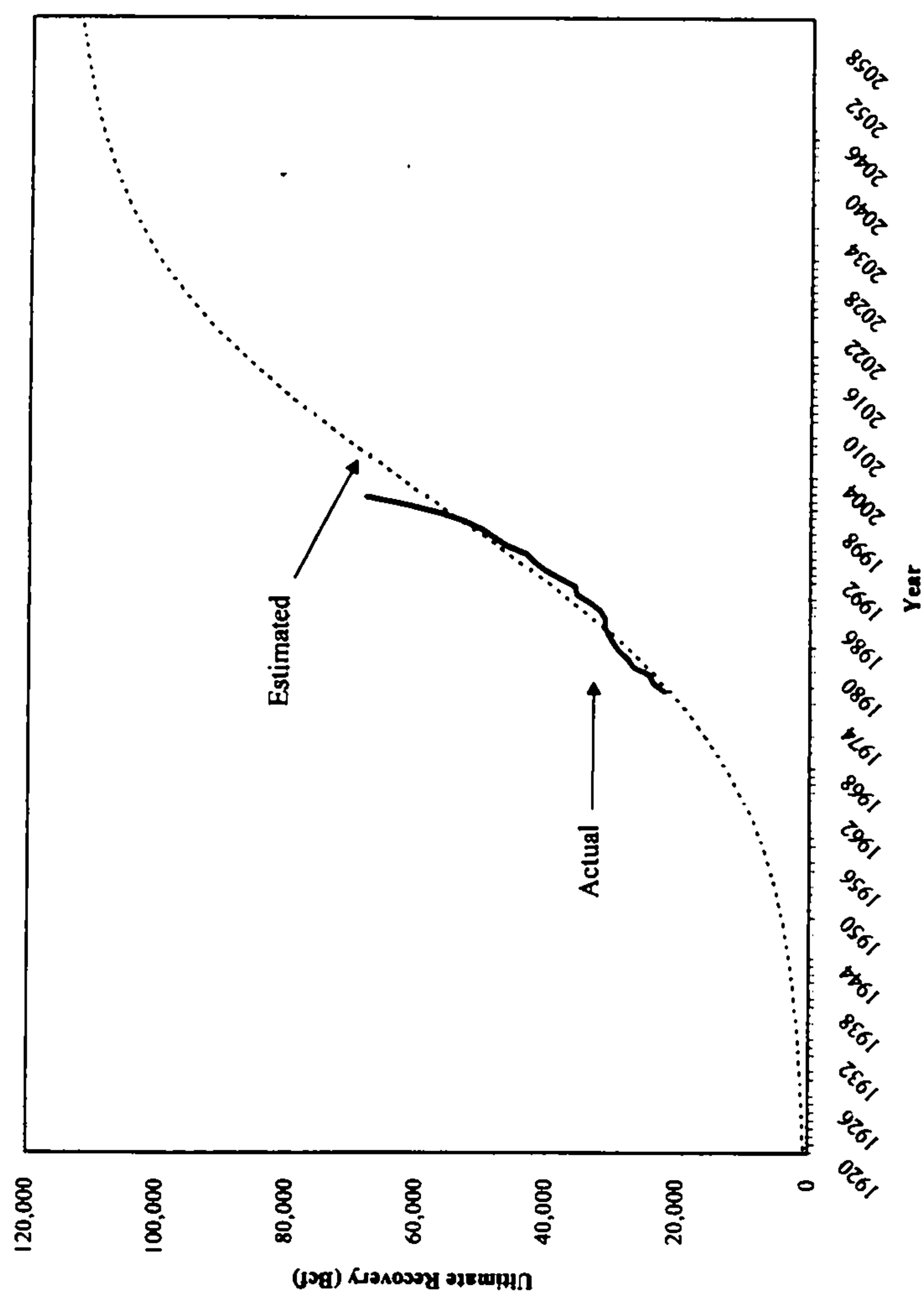
		for graph											
Change to Estimated Ult. Rec.	Estimated Ult. Rec.	Year	Ult. Rec. Actual	Ult. Rec. Estimated	Change in Actual Ult. Rec.	Year	Actual Ult. Rec. Percent	Estimated Ult. Rec. Percent	X	X^2	Ln(1/Y-1) Y	Y^2	X*Y
994.67	19,281	1975		19,281		1975	0.00	0.168	-1	1.00			
1,037.41	20,319	1976		20,319		1976	0.00	0.177	0	0.00			
1,080.75	21,399	1977	22,174	21,399		1977	0.19	0.186	1	1.00	1.432	2.050	1.432
1,124.56	22,524	1978	23,829	22,524	1,655	1978	0.21	0.196	2	4.00	1.342	1.801	2.684
1,168.70	23,693	1979	24,498	23,693	669	1979	0.21	0.206	3	9.00	1.307	1.708	3.920
1,213.01	24,906	1980	26,965	24,906	2,467	1980	0.23	0.217	4	16.00	1.183	1.400	4.733
1,257.31	26,163	1981	27,799	26,163	834	1981	0.24	0.228	5	25.00	1.143	1.307	5.716
1,301.44	27,464	1982	29,190	27,464	1,391	1982	0.25	0.239	6	36.00	1.078	1.163	6.470
1,345.18	28,810	1983	30,063	28,810	873	1983	0.26	0.251	7	49.00	1.039	1.079	7.270
1,388.34	30,198	1984	30,768	30,198	705	1984	0.27	0.263	8	64.00	1.007	1.014	8.057
1,430.69	31,629	1985	31,440	31,629	672	1985	0.27	0.275	9	81.00	0.977	0.955	8.797
1,472.01	33,101	1986	31,315	33,101	(125)	1986	0.27	0.288	10	100.00	0.983	0.966	9.830
1,512.08	34,613	1987	32,112	34,613	797	1987	0.28	0.301	11	121.00	0.948	0.899	10.431
1,550.65	36,163	1988	33,688	36,163	1,576	1988	0.29	0.314	12	144.00	0.881	0.776	10.574
1,587.50	37,751	1989	35,674	37,751	1,986	1989	0.31	0.328	13	169.00	0.799	0.639	10.389
1,622.38	39,373	1990	35,967	39,373	293	1990	0.31	0.342	14	196.00	0.787	0.620	11.022
1,655.08	41,028	1991	38,097	41,028	2,130	1991	0.33	0.357	15	225.00	0.702	0.493	10.536
1,685.35	42,714	1992	40,447	42,714	2,350	1992	0.35	0.371	16	256.00	0.612	0.374	9.784
1,713.01	44,427	1993	42,178	44,427	1,731	1993	0.37	0.386	17	289.00	0.546	0.298	9.284
1,737.83	46,165	1994	43,382	46,165	1,204	1994	0.38	0.401	18	324.00	0.501	0.251	9.024
1,759.65	47,924	1995	46,492	47,924	3,110	1995	0.40	0.417	19	361.00	0.388	0.150	7.366
1,778.29	49,702	1996	48,422	49,702	1,930	1996	0.42	0.432	20	400.00	0.318	0.101	6.369
1,793.62	51,496	1997	50,235	51,496	1,813	1997	0.44	0.448	21	441.00	0.254	0.065	5.335
1,805.51	53,302	1998	52,890	53,302	2,655	1998	0.46	0.463	22	484.00	0.161	0.026	3.535
1,813.87	55,115	1999	56,504	55,115	3,614	1999	0.49	0.479	23	529.00	0.035	0.001	0.797
1,818.64	56,934	2000	61,706	56,934	5,202	2000	0.54	0.495	24	576.00	(0.147)	0.021	(3.517)
1,819.77	58,754	2001	68,213	58,754	6,507	2001	0.59	0.511	25	625.00	(0.377)	0.142	(9.425)
1,817.26	60,571	2002		60,571		2002		0.527	325	5,525.00	17.901	18.301	150.414
1,811.13	62,382	2003		62,382		2003		0.542					
1,801.42	64,184	2004		64,184		2004		0.558	B =	(0.06)			
1,788.22	65,972	2005		65,972		2005		0.574	A =	1.53898			
1,771.62	67,744	2006		67,744		2006		0.589	R^2 =	0.95005			
1,751.76	69,495	2007		69,495		2007		0.604					
1,728.79	71,224	2008		71,224		2008		0.619					
1,702.87	72,927	2009		72,927		2009		0.634					
1,674.20	74,601	2010		74,601		2010		0.649					
1,642.99	76,244	2011		76,244		2011		0.663					
1,609.44	77,854	2012		77,854		2012		0.677					
1,573.79	79,427	2013		79,427		2013		0.691					
1,536.26	80,964	2014		80,964		2014		0.704					
1,497.09	82,461	2015		82,461		2015		0.717					
1,456.52	83,917	2016		83,917		2016		0.730					
1,414.78	85,332	2017		85,332		2017		0.742					
1,372.10	86,704	2018		86,704		2018		0.754					
1,328.70	88,033	2019		88,033		2019		0.766					
1,284.79	89,318	2020		89,318		2020		0.777					
1,240.57	90,558	2021		90,558		2021		0.787					
1,196.24	91,754	2022		91,754		2022		0.798					
1,151.98	92,906	2023		92,906		2023		0.808					
1,107.95	94,014	2024		94,014		2024		0.818					
1,064.30	95,079	2025		95,079		2025		0.827					
1,021.17	96,100	2026		96,100		2026		0.836					
978.70	97,079	2027		97,079		2027		0.844					
936.97	98,016	2028		98,016		2028		0.852					
896.10	98,912	2029		98,912		2029		0.860					

Trailblazer Pipeline Company
Docket No. RP03-162-000
Corrected--Extrapolation of Ultimate Recovery
using an S-Curve Fit
Inflection Point equals 2001
(Colorado, Wyoming)

Est. Ultimate Recovery 115,000 R^2 = 0.95005

Change in Estimated Ult. Rec.	Estimated Ult. Rec	for graph Year	Ult. Rec. Actual	Ult. Rec. Estimated	Change in Actual Ult. Rec.	Year	Actual Ult. Rec. Percent	Estimated Ult. Rec. Percent	X	X^2	Ln(1/Y-1) Y	Y^2	X*Y
856.17	99,768	2030		99,768		2030		0.868					
817.25	100,585	2031		100,585		2031		0.875					
779.40	101,364	2032		101,364		2032		0.881					
742.66	102,107	2033		102,107		2033		0.888					
707.07	102,814	2034		102,814		2034		0.894					
672.67	103,487	2035		103,487		2035		0.900					
639.46	104,126	2036		104,126		2036		0.905					
607.47	104,734	2037		104,734		2037		0.911					
576.69	105,310	2038		105,310		2038		0.916					
547.12	105,858	2039		105,858		2039		0.921					
518.76	106,376	2040		106,376		2040		0.925					
491.58	106,868	2041		106,868		2041		0.929					
465.58	107,333	2042		107,333		2042		0.933					
440.73	107,774	2043		107,774		2043		0.937					
417.00	108,191	2044		108,191		2044		0.941					
394.37	108,586	2045		108,586		2045		0.944					
372.80	108,958	2046		108,958		2046		0.947					
352.27	109,311	2047		109,311		2047		0.951					
332.74	109,643	2048		109,643		2048		0.953					
314.18	109,958	2049		109,958		2049		0.956					
296.55	110,254	2050		110,254		2050		0.959					
279.82	110,534	2051		110,534		2051		0.961					
263.95	110,798	2052		110,798		2052		0.963					
248.90	111,047	2053		111,047		2053		0.966					
234.66	111,281	2054		111,281		2054		0.968					
221.17	111,503	2055		111,503		2055		0.970					
208.40	111,711	2056		111,711		2056		0.971					
196.33	111,907	2057		111,907		2057		0.973					
184.91	112,092	2058		112,092		2058		0.975					
174.13	112,266	2059		112,266		2059		0.976					
163.94	112,430	2060		112,430		2060		0.978					
	112,585	2061		112,585		2061		0.979					
	112,730	2062		112,730		2062		0.980					
	112,867	2063		112,867		2063		0.981					
	112,995	2064		112,995		2064		0.983					
	113,116	2065		113,116		2065		0.984					

Trailblazer Pipeline Company
Docket No. RP03-162-000
Extrapolation of Ultimate Recovery
Colorado, Wyoming



Trailblazer Pipiline Company
Docket No. RP03-162-000
Extrapolation of Historical Production
(for Ultimate Recovery = 115.000 Bcf)
(Colorado, Wyoming)

R^2 = 0.88219

PEAK YEAR= 2016

Cumulative Production	Year	Actual Production	Estimated Production	$(X-PY)^2$ X	X^2	Ln(Y) Y	Y^2	X*Y
	1977	489	387	1.521	2.313.441	6.192	38.345	9.418.583
	1978	496	421	1.444	2.085.136	6.207	38.522	8.962.296
	1979	511	458	1.369	1.874.161	6.236	38.892	8.537.590
	1980	579	496	1.296	1.679.616	6.361	40.466	8.244.248
	1981	588	536	1.225	1.500.625	6.377	40.663	7.811.491
	1982	587	579	1.156	1.336.336	6.375	40.641	7.369.529
	1983	570	623	1.089	1.185.921	6.346	40.267	6.910.398
	1984	655	669	1.024	1.048.576	6.485	42.050	6.640.266
	1985	599	717	961	923.521	6.395	40.899	6.145.846
	1986	590	767	900	810.000	6.380	40.706	5.742.110
	1987	615	819	841	707.281	6.422	41.237	5.400.584
	1988	698	872	784	614.656	6.548	42.879	5.133.804
	1989	811	926	729	531.441	6.698	44.867	4.883.037
	1990	812	982	676	456.976	6.700	44.883	4.528.862
	1991	921	1.038	625	390.625	6.825	46.587	4.265.913
	1992	1.034	1.096	576	331.776	6.941	48.180	3.998.125
	1993	1.100	1.154	529	279.841	7.003	49.043	3.704.622
	1994	1.227	1.213	484	234.256	7.112	50.585	3.442.366
	1995	1.320	1.271	441	194.481	7.185	51.630	3.168.756
	1996	1.322	1.330	400	160.000	7.187	51.652	2.874.760
	1997	1.453	1.388	361	130.321	7.281	53.019	2.628.580
	1998	1.514	1.446	324	104.976	7.323	53.619	2.372.493
	1999	1.932	1.503	289	83.521	7.566	57.249	2.186.664
	2000	1.829	1.558	256	65.536	7.512	56.423	1.922.950
37.288	2001	2.168	1.613	225	50.625	7.682	59.006	1.728.351
38.953	2002		1.665	19.525	19.093.645	169	1.152	128.022
40.668	2003		1.715					
42.430	2004		1.763	B =	(0.00110)			
44.239	2005		1.808	A =	7.63321			
46.089	2006		1.850	R^2 =	0.88219			
47.978	2007		1.889					
49.904	2008		1.925					
51.861	2009		1.957					
53.846	2010		1.985					
55.856	2011		2.010					
57.885	2012		2.030					
59.931	2013		2.045					
61.987	2014		2.057					

Trailblazer Pipiline Company
Docket No. RP03-162-000
Extrapolation of Historical Production
(for Ultimate Recovery = 115.000 Bcf)
(Colorado, Wyoming)

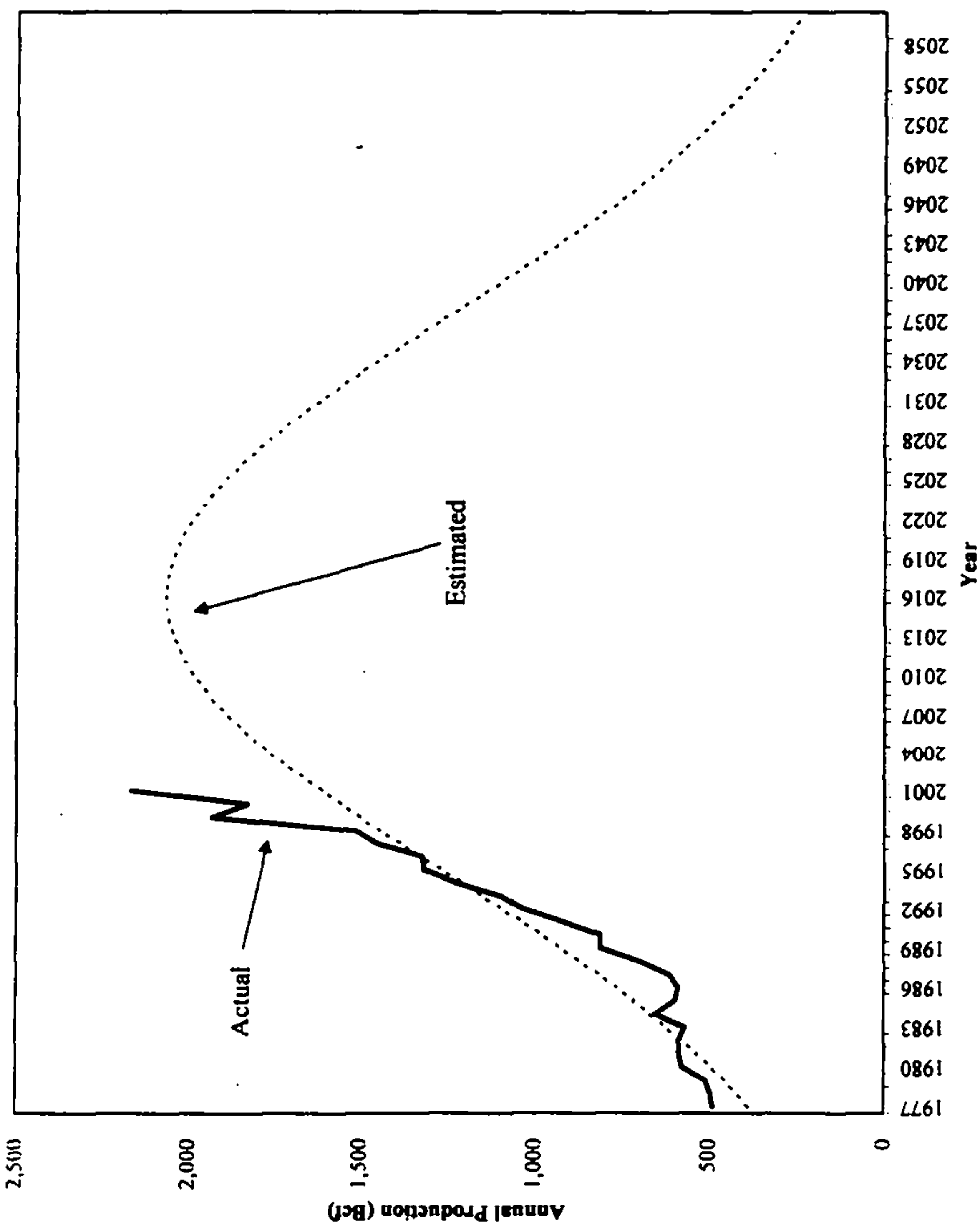
R^2 = 0.88219

PEAK YEAR= 2016

Cumulative Production	Year	Actual Production	Estimated Production	$(X-PY)^2$ X	X^2	Ln(Y) Y	Y^2	X*Y
64.051	2015		2.063					
66.116	2016		2.066					
68.180	2017		2.063					
70.236	2018		2.057					
72.282	2019		2.045					
74.311	2020		2.030					
76.321	2021		2.010					
78.306	2022		1.985					
80.263	2023		1.957					
82.189	2024		1.925					
84.078	2025		1.889					
85.928	2026		1,850					
87.737	2027		1.808					
89.499	2028		1.763					
91.214	2029		1.715					
92.879	2030		1.665					
94.492	2031		1.613					
96.050	2032		1.558					
97.553	2033		1,503					
98.999	2034		1.446					
100.387	2035		1.388					
101.717	2036		1.330					
102.989	2037		1.271					
104.201	2038		1.213					
105.355	2039		1.154					
106.451	2040		1.096					
107.489	2041		1.038					
108.471	2042		982					
109.397	2043		926					
110.268	2044		872					
111.087	2045		819					
111.854	2046		767					
112.571	2047		717					
113.240	2048		669					
113.863	2049		623					
114.442	2050		579					
114.978	2051		536					
115.475	2052		496					

Trailblazer Pipeline Company
Docket No. RP03-162-000
Extrapolation of Production

Colorado, Wyoming



Trailblazer Pipiline Company
Docket No. RP03-162-000
Determination of Peak Year
(Dry Gas in Bcf)
Colorado, Wyoming

		Cumulative Production				
Year	Estimated Ult. Rec.	Pk. Yr. 2014	Pk. Yr. 2015	Pk. Yr. 2016	Pk. Yr. 2017	Pk. Yr. 2025
1995	47.924					
1996	49.702					
1997	51.496					
1998	53.302					
1999	55.115					
2000	56.934					
2001	58.754	37.288	37.288	37.288	37.288	37.288
2002	60.571	38.931	38.942	38.953	38.962	39.022
2003	62.382	40.620	40.644	40.668	40.689	40.822
2004	64.184	42.351	42.392	42.430	42.467	42.688
2005	65.972	44.121	44.182	44.239	44.292	44.620
2006	67.744	45.927	46.011	46.089	46.162	46.615
2007	69.495	47.766	47.876	47.978	48.075	48.673
2008	71.224	49.634	49.773	49.904	50.026	50.792
2009	72.927	51.525	51.698	51.861	52.014	52.970
2010	74.601	53.437	53.648	53.846	54.033	55.206
2011	76.244	55.365	55.618	55.856	56.080	57.496
2012	77.854	57.305	57.604	57.885	58.151	59.839
2013	79.427	59.251	59.601	59.931	60.243	62.231
2014	80.964	61.200	61.604	61.987	62.350	64.669
2015	82.461	63.146	63.611	64.051	64.468	67.151
2016	83.917	65.085	65.614	66.116	66.593	69.673
2017	85.332	67.013	67.611	68.180	68.720	72.230
2018	86.704	68.925	69.597	70.236	70.845	74.820
2019	88.033	70.817	71.567	72.282	72.963	77.438
2020	89.318	72.684	73.517	74.311	75.070	80.080
2021	90.558	74.523	75.442	76.321	77.161	82.743
2022	91.754	76.329	77.339	78.306	79.233	85.421
2023	92.906	78.100	79.204	80.263	81.280	88.110
2024	94.014	79.831	81.033	82.189	83.299	90.805
2025	95.079	81.519	82.823	84.078	85.286	93.504
2026	96.100	83.163	84.571	85.928	87.238	96.199
2027	97.079	84.758	86.273	87.737	89.151	98.888
2028	98.016	86.303	87.927	89.499	91.021	101.566
2029	98.912	87.796	89.532	91.214	92.846	104.229
2030	99.768	89.235	91.084	92.879	94.623	106.871
2031	100.585	90.620	92.582	94.492	96.350	109.489
2032	101.364	91.947	94.024	96.050	98.025	112.079
2033	102.107	93.218	95.411	97.553	99.645	114.636
2034	102.814	94.432	96.740	98.999	101.210	117.158
2035	103.487	95.588	98.011	100.387	102.717	119.640
2036	104.126	96.687	99.224	101.717	104.166	122.078
2037	104.734	97.729	100.379	102.989	105.556	124.470
2038	105.310	98.714	101.476	104.201	106.887	126.813

Trailblazer Pipiline Company
Docket No. RP03-162-000
Determination of Peak Year
(Dry Gas in Bcf)
Colorado, Wyoming

Year	Estimated Ult. Rec.	Cumulative Production Pk. Yr. 2014	Pk. Yr. 2015	Pk. Yr. 2016	Pk. Yr. 2017	Pk. Yr. 2025
2039	105.858	99.644	102.516	105.355	108.158	129.103
2040	106.376	100.520	103.500	106.451	109.370	131.339
2041	106.868	101.342	104.428	107.489	110.523	133.517
2042	107.333	102.113	105.301	108.471	111.618	135.636
2043	107.774	102.833	106.121	109.397	112.654	137.694
2044	108.191	103.504	106.890	110.268	113.634	139.689
2045	108.586	104.129	107.609	111.087	114.558	141.621
2046	108.958	104.709	108.279	111.854	115.428	143.487
2047	109.311	105.246	108.903	112.571	116.245	145.287
2048	109.643	105.742	109.482	113.240	117.010	147.021
2049	109.958	106.199	110.019	113.863	117.726	148.688
2050	110.254	106.619	110.515	114.442	118.395	150.289
2051	110.534	107.005	110.972	114.978	119.017	151.822
2052	110.798	107.358	111.393	115.475	119.595	153.289
2053	111.047	107.680	111.780	115.932	120.131	154.690
2054	111.281	107.973	112.134	116.354	120.627	156.026
2055	111.503	108.239	112.457	116.741	121.085	157.298
2056	111.711	108.481	112.752	117.096	121.507	158.506
2057	111.907	108.699	113.020	117.421	121.895	159.652
2058	112.092	108.896	113.264	117.717	122.251	160.738
2059	112.266	109.074	113.484	117.987	122.577	161.765
2060	112.430	109.233	113.683	118.232	122.875	162.734
2061	112.585	109.376	113.863	118.455	123.147	163.647
2062	112.730	109.503	114.024	118.656	123.394	164.506
2063	112.867	109.617	114.169	118.837	123.618	165.313
2064	112.995	109.718	114.299	119.001	123.821	166.070
2065	113.116	109.808	114.415	119.148	124.004	166.778
2066	113.230	109.887	114.518	119.280	124.170	167.440
2067	113.337	109.957	114.610	119.398	124.319	168.058
2068	113.438	110.019	114.691	119.503	124.453	168.633
2069	113.532	110.073	114.763	119.597	124.573	169.168
2070	113.621	110.121	114.827	119.680	124.680	169.665
2071	113.705	110.162	114.883	119.754	124.776	170.125
2072	113.783	110.199	114.932	119.820	124.861	170.551
2073	113.857	110.230	114.975	119.878	124.937	170.944
2074	113.927	110.258	115.013	119.928	125.004	171.307
2075	113.992	110.282	115.046	119.973	125.064	171.640

Trailblazer Pipiline Company
Docket No. RP03-162-000
Historical Additions to Reserves
(Dry Gas in Bcf)
(Colorado, Wyoming)

Year	Reserve Additions
1996	545
1997	2,213
1998	1,219
1999	1,233
2000	2,770
2001	4,798
Average	2,130

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Report (1996-2001), Energy Information Administration.*

Trailblazer Pipeline Company
Docket No. RP03-162-000
Exploratory Drilling in Company's Supply Area
- (Colorado, Wyoming)
(Number of Wells)

Year	Estimate for Current Year	Forecast for Next Year
1998	541	441
1999	222	251
2000	405	477
2001	1,776	1,514
2002	351	284
Average	659	593

Sources: Oil & Gas Journal, January 25, 1999, page 74.
Oil & Gas Journal, January 31, 2000, page 65.
Oil & Gas Journal, January 29, 2001, page 86.
Oil & Gas Journal, January 28, 2002, page 87.
Oil & Gas Journal, January 27, 2003, page 83.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Comparison of Staff's Esitmate of Undiscovered Gas to PGC Estimate
(Volume in Bcf)

Staff Estimate (12/31/2001)	Level
Undiscovered Gas at 115,000 Bcf Ultimate Recovery Level	46,787
Undiscovered Gas as 35-year life (to 2036)	33,504

PGC Estimate (12/31/2000)		Probable	Possible	Level Total
		34,428	53,031	87,459
Components of the PGC Total				
P-510	Powder River			
	0-15,000 feet	1,435	2,153	3,588
	15,000-30,000 feet	–	–	–
	Coalbed Methane	6,010	18,031	24,041
P-515	Big Horn			
	0-15,000 feet	672	530	1,202
	15,000-30,000 feet	170	616	786
	Coalbed Methane	–	25	25
P-530	Greater Green River, etc.			
	0-15,000 feet	8,997	4,851	13,848
	15,000-30,000 feet	979	5,696	6,675
	Coalbed Methane	–	–	–
P-535	Denver, etc.			
	0-15,000 feet	1,324	1,215	2,539
	15,000-30,000 feet	–	–	–
	Coalbed Methane	–	–	–
P-540	Uinta-Piceance, etc.			
	0-15,000 feet	14,208	15,599	29,807
	15,000-30,000 feet	500	200	700
	Coalbed Methane	133	4,115	4,248

Source: Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee, December 21, 2000. Potential Gas Agency, March 2001, pages 130, 131.

Exhibit No. S-11
Page 21 of 40 pages.
Schedule No. 12, Page 2 of 2 pages.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Map of PGC Resource Areas

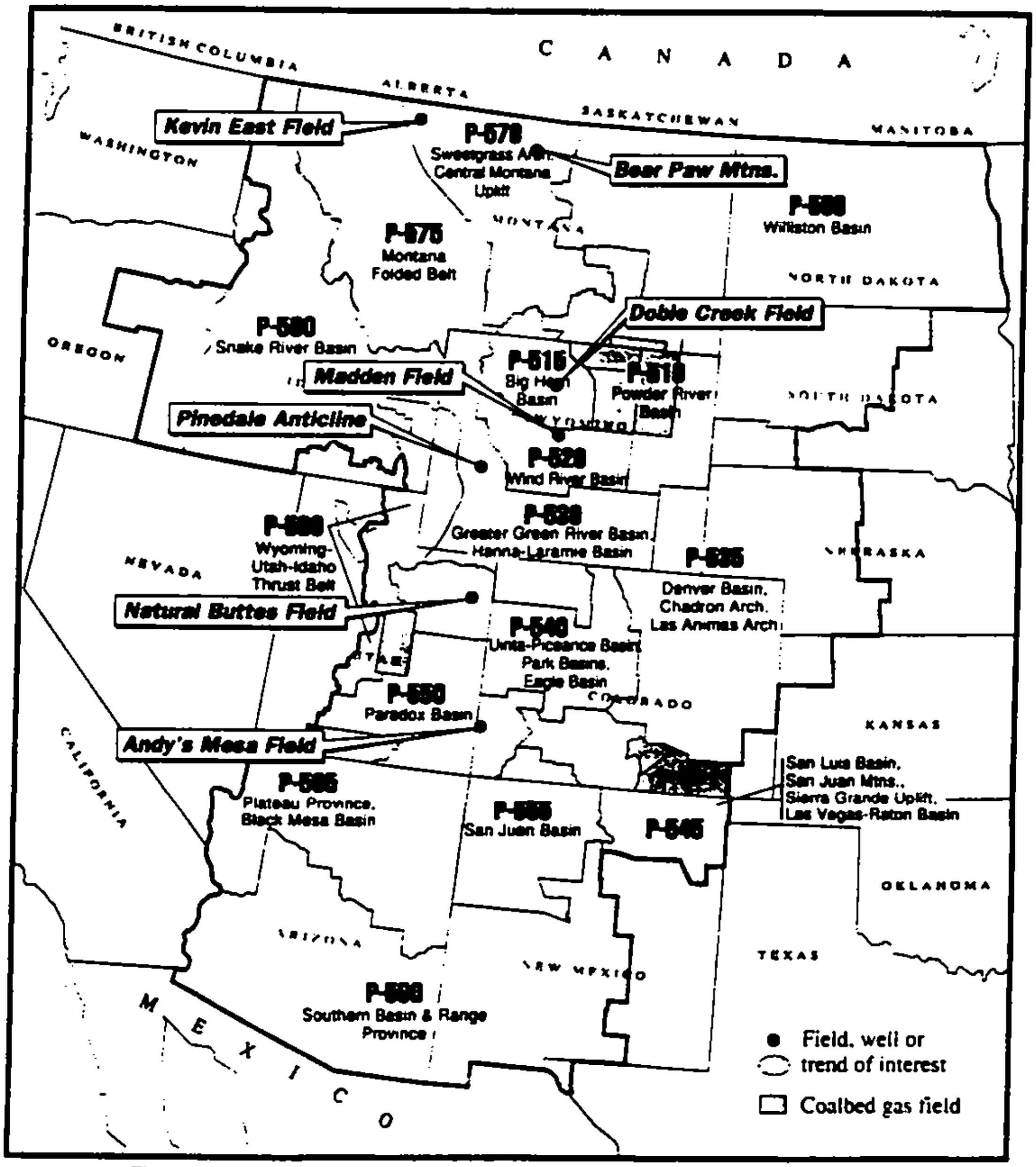


Figure 60. Geologic provinces and selected field activities in the Rocky Mountain Area.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Description of PGC Resource Categories

PROBABLE RESOURCES are connected with known fields. They are the most certain of potential supplies. Reserves in this category are expected to come from extensions and new pool discoveries in existing fields.

POSSIBLE RESOURCES are not connected with known fields, but are connected with known productive formations. They are not as certain of potential supplies as probable resources. Reserves in this category are expected to come from new field discoveries in known productive formations.

SPECULATIVE RESOURCES are connected with formations that have not yet proven to contain natural gas reserves. They are the least certain of potential supplies. Reserves in this category are expected to come from discoveries in formations or provinces that have not previously yielded any reserves.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Outlook for Natural Gas Consumption
DRI-WEFA, Inc.
(Trillion Btu)

Year	East North Central Region Consumption (1)	Total U.S. Consumption
1999	3,837	22.284
2000	3,893	23,362
2001	3,833	23.527
2002	3,965	24.135
2003	4,040	24,671
2004	4,054	25,010
2005	4,083	25,451
2010	4,437	28.099
2015	4,973	30,862
2020	5,278	32.498

(1) -- East North Central Region is comprised of Ohio. Wisconsin. Indiana. Michigan. and Illinois.

Source: *U.S. Energy Outlook, Spring-Summer 2001*, *DRI-WEFA, Inc., 2001, page 78.*

Trailblazer Pipeline Company
Docket No. RP03-162-000
Outlook for Natural Gas Consumption, U. S.
Energy Information Administration
(Quadrillion BTU/year)

Year	Natural Gas Consumption
2000	24.07
2001	23.26
2005	25.24
2010	27.75
2015	30.25
2020	32.96
2025	35.81

Source: Annual Energy Outlook 2003, with Projections to 2025, Energy Information Adminstration, January, 2003, page 119.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Company Response to Staff Data Request (KJP-1), Item No. 17

TRAILBLAZER PIPELINE COMPANY

Data Response Form for
Docket No. RP03-162-000

Requesting Party: FERC Staff

Data Request Reference: KJP-1

Data Request No: 17

Question

Exhibit No. TPC-1, page 8, lines 14 through 16, please provide a list of firm shipper agreements, including for each agreement: the name of the shipper, the date the contract expires, any rollover or evergreen provisions, if the contract has been renewed in the past, and if the shipper is affiliated with Trailblazer.

Response

See attached. None of the agreements listed have rollover or evergreen provisions. Any agreement of one year or greater in length is subject to the right of first refusal process set out in Trailblazer's tariff.

Prepared by: Joan Soland

Trailblazer Pipeline Company
Docket No. RP03-162-000
Company Response to Staff Data Request (KJP-1), Item No. 17

TRAILBLAZER PIPELINE COMPANY
CURRENT FIRM TRANSPORTATION SHIPPERS
RESPONSES TO FERC STAFF REQUEST KJP-1, #17

SHIPPER NAME	AFFILIATE	PREVIOUSLY RENEWED	CONTRACT NUMBER	CONTRACT END DATE	MDQ	
AMERICAN GYPSUM COMPANY			928679	10/31/2003	272	
AMOCO PRODUCTION COMPANY			928645	10/31/2003	271	
BADAK GAS MARKETING, INC.			912502	7/31/2007	10000	
BLACK HILLS EXPLORATION AND PRODUCTION INC.			928610	10/31/2003	272	
BP CANADA ENERGY MARKETING CORPORATION			928646	10/31/2003	271	
BP ENERGY COMPANY			928642	10/31/2003	271	
BURLINGTON RESOURCES GATHERING INC.			928663	10/31/2003	272	
BURLINGTON RESOURCES OFFSHORE INC.			928661	10/31/2003	272	
BURLINGTON RESOURCES OIL & GAS COMPANY			928662	10/31/2003	271	
BURLINGTON RESOURCES TRADING INC.			928659	10/31/2003	272	
CENTRAL ALABAMA GAS SUPPLY CORP.			928628	10/31/2003	272	
CENTRAL ALABAMA WATER SUPPLY CORP.			928626	10/31/2003	272	
CHEVRON U.S.A. PRODUCTION COMPANY, A DIVISION OF CHEVRON U.S			912541	7/31/2007	20000	
CHEVRON U.S.A. PRODUCTION COMPANY, A DIVISION OF CHEVRON U.S			928690	10/31/2003	271	
CIG RESOURCES COMPANY		X	913561	11/30/2012	72780	
CIG RESOURCES COMPANY		X	913562	11/30/2012	21200	
CIG RESOURCES COMPANY		X	914381	8/31/2009	25000	
CIG RESOURCES COMPANY		X	914555	8/31/2009	25880	
CINERGY MARKETING & TRADING, LP			928674	10/31/2003	272	
CINERGY TRANSPORTATION, LLC			928676	10/31/2003	272	
CITY OF HASTINGS, HASTINGS UTILITIES		X	907621	9/30/2005	14840	
COLORADO INTERSTATE GAS COMPANY			912500	7/31/2007	10000	
CONCORD ENERGY LLC			928489	10/31/2053	22000	1/
CONCORD ENERGY LLC			928648	10/31/2003	272	
CONOCO INC.			928615	10/31/2003	272	
DEVON ENERGY PRODUCTION COMPANY, L.P.			919366	5/6/2012	33000	
DUKE ENERGY FUELS, L.P.		X	927055	12/31/2007	75000	
DUKE ENERGY FUELS, L.P.			928689	10/31/2003	272	
DUKE ENERGY NORTH AMERICA			928688	10/31/2003	272	
DUKE ENERGY TRADING AND MARKETING, LLC		X	910642	10/31/2007	5000	
DUKE ENERGY TRADING AND MARKETING, LLC			928664	10/31/2003	272	
E PRIME, INC.			928814	10/31/2003	272	
EL PASO MERCHANT ENERGY, L.P.			919853	11/30/2008	5951	
ENERGY CAPITAL MANAGEMENT LLC			928649	10/31/2003	272	
ENGLAND RESOURCES CORPORATION			928684	10/31/2003	271	

TRAILBLAZER PIPELINE COMPANY
CURRENT FIRM TRANSPORTATION SHIPPERS
RESPONSES TO FERC STAFF REQUEST KJP-1, #17

SHIPPER NAME	AFFILIATE	PREVIOUSLY RENEWED	CONTRACT NUMBER	CONTRACT END DATE	MDQ	
ENSERCO ENERGY INC.			928609	10/31/2003	272	
FAIRFIELD MANAGEMENT INC			928650	10/31/2003	272	
FNA & ASSOCIATES, L.L.C.			928608	10/31/2003	271	
FRONTIER GAS PIPELINE CO			928633	10/31/2003	272	
GEARY ENERGY LLC			928685	10/31/2003	271	
GEARY GAS MARKETING, LLC			928686	10/31/2003	272	
HEINLE & ASSOCIATES, INC			928682	10/31/2003	272	
IGI RESOURCES, INC.			928647	10/31/2003	271	
J M HUBER CORPORATION			919361	5/6/2013	41000	
JURASSIC RESOURCES DEVELOPMENT N.A. LLC			928655	10/31/2003	272	
KANSAS ENERGY PARTNERS, LLC.			927605	12/81/2007	4540	
KENNEDY OIL			928612	10/31/2003	271	
KERR MCGEE ENERGY SERV. CORP.			914925	3/31/2005	5920	
KINDER MORGAN INTERSTATE GAS TRANSMISSION, LLC	X	X	901362	12/31/2007	5000	
LONE MOUNTAIN PRODUCTION CO.			928675	10/31/2003	271	
MARALEX RESOURCES, INC.			928677	10/31/2003	272	
MARATHON OIL COMPANY			912479	7/31/2007	21200	
MARATHON OIL COMPANY			919467	5/6/2012	22500	
MARATHON OIL COMPANY			927144	5/6/2012	100000	
MARATHON OIL COMPANY			928602	10/31/2003	272	
MESA HYDROCARBONS INC			928680	10/31/2003	271	
MISSOURI RIVER ROYALTY CORPORATION			928654	10/31/2003	271	
MONTANA HEARTLAND, LLC			928657	10/31/2003	272	
NATIONAL FUEL CORPORATION			928600	10/31/2003	271	
NATIONAL FUEL MARKETING COMPANY			928599	10/31/2003	272	
NICO RESOURCES, LLC			928683	10/31/2003	272	
OCCIDENTAL ENERGY MARKETING, INC.			928644	10/31/2003	271	
ONEOK ENERGY MARKETING AND TRADING COMPANY, L.P.		X	911109	4/30/2006	22000	2/
ONEOK ENERGY MARKETING AND TRADING COMPANY, L.P.			912114	3/31/2018	21200	
ONEOK ENERGY MARKETING AND TRADING COMPANY, L.P.		X	912252	4/30/2012	10600	
ONEOK ENERGY MARKETING AND TRADING COMPANY, L.P.			928601	10/31/2003	272	
PENNACO ENERGY, INC.			928603	10/31/2003	272	
PINE GAS GATHERING, LLC			928658	10/31/2003	272	
PRIORITY OIL & GAS CORP.			928678	10/31/2003	272	
QUESTAR ENERGY TRADING COMPANY			928619	10/31/2003	272	

Trailblazer Pipeline Company
Docket No. RP03-162-000
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Exhibit No. S-11
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Schedule No. 16, Page 3 of 5 pages.

Trailblazer Pipeline Company
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Company Response to Staff Data Request (KJP-1), Item No. 17

TRAILBLAZER PIPELINE COMPANY
CURRENT FIRM TRANSPORTATION SHIPPERS
RESPONSES TO FERC STAFF REQUEST KJP-1, #17

SHIPPER NAME	AFFILIATE	PREVIOUSLY RENEWED	CONTRACT NUMBER	CONTRACT END DATE	MDQ
QUESTAR EXPLORATION AND PRODUCTION INC.			928616	10/31/2003	272
QUESTAR GAS MANAGEMENT			928618	10/31/2003	272
RAINBOW GAS COMPANY			928652	10/31/2003	272
RELIANT ENERGY SERVICES, INC.			912499	7/31/2007	39600
SANDIA RESOURCES CORPORATION			928611	10/31/2003	272
SELECT NATURAL GAS L.L.C.			928613	10/31/2003	272
SEMPRA ENERGY TRADING CORP.			928651	10/31/2003	272
SHENANDOAH ENERGY, INC.			928617	10/31/2003	271
STERLING ENERGY COMPANY			928681	10/31/2003	271
TENASKA ALABAMA III, INC.			928668	10/31/2003	271
TENASKA ALABAMA III, L.P.			928669	10/31/2003	272
TENASKA ARKANSAS I, L.P.			928667	10/31/2003	272
TENASKA ARKANSAS, INC.			928666	10/31/2003	271
TENASKA ENERGY SERVICES, LLC			928638	10/31/2003	272
TENASKA FREDRICKSON, INC.			928635	10/31/2003	272
TENASKA GAS COMPANY			928640	10/31/2003	272
TENASKA GAS STORAGE, LLC			928641	10/31/2003	271
TENASKA GRIMES II, L.P.			928621	10/31/2003	272
TENASKA GRIMES, INC.			928629	10/31/2003	272
TENASKA II, INC.			928637	10/31/2003	272
TENASKA INDIANA I, L.P.			928685	10/31/2003	272
TENASKA INDIANA, INC.			928687	10/31/2003	272
TENASKA MARKETING VENTURES			928620	10/31/2003	272
TENASKA MARKETING, INC.			928643	10/31/2003	271
TENASKA MICHIGAN II, INC.			928670	10/31/2003	272
TENASKA MICHIGAN II, L.P.			928671	10/31/2003	272
TENASKA MICHIGAN PARTNERS, LP			928625	10/31/2003	272
TENASKA MICHIGAN, I.L.P.			928624	10/31/2003	272
TENASKA MICHIGAN, INC			928623	10/31/2003	272
TENASKA MINNESOTA I.L.P.			928627	10/31/2003	271
TENASKA MINNESOTA, INC			928622	10/31/2003	271
TENASKA OKLAHOMA II, INC.			928672	10/31/2003	272
TENASKA OKLAHOMA II, L.P.			928673	10/31/2003	272
TENASKA OPERATIONS, INC.			928632	10/31/2003	272
TENASKA RUSK, INC.			928630	10/31/2003	272

TRAILBLAZER PIPELINE COMPANY
CURRENT FIRM TRANSPORTATION SHIPPERS
RESPONSES TO FERC STAFF REQUEST KJP-1, #17

SHIPPER NAME	AFFILIATE	PREVIOUSLY RENEWED	CONTRACT NUMBER	CONTRACT END DATE	MDQ
TENASKA V, INC.			928631	10/31/2003	272
TENASKA WASHINGTON II, LP			928636	10/31/2003	272
TENASKA WATER SERVICES, LP			928634	10/31/2003	272
THE LOUISIANA LAND & EXPLORATION COMPANY			928660	10/31/2003	272
TMV CORP			928639	10/31/2003	272
UBS AG, LONDON BRANCH			928607	10/31/2003	272
UNITED ENERGY CORPORATION			928656	10/31/2003	272
UNITED ENERGY PARTNERS			928605	10/31/2003	271
UNITED ENERGY TRADING, LLC			928653	10/31/2003	272
UNITED STATES GYPSUM COMPANY		X	911097	3/31/2008	1466
VIRGINIA POWER ENERGY MARKETING			928604	10/31/2003	272
WESTERN GAS RESOURCES, INC.		X	911341	1/1/2008	30740
WESTERN GAS RESOURCES, INC.			912512	2/29/2008	10000
WESTERN GAS RESOURCES, INC.			919357	5/6/2012	57500
WESTERN GAS RESOURCES, INC.			928606	10/31/2003	272
WILLIAMS ENERGY MARKETING & TRADING COMPANY			911871	10/31/2007	5800
WILLIAMS ENERGY MARKETING & TRADING COMPANY			911925	11/30/2007	4320
WILLIAMS ENERGY MARKETING & TRADING COMPANY			915397	8/31/2005	12100
WILLIAMS ENERGY MARKETING & TRADING COMPANY			919359	5/6/2012	70000
WILLIAMS ENERGY MARKETING & TRADING COMPANY		X	927599	1/1/2008	21200

1/ WINTER ONLY AGREEMENT (EFFECTIVE NOVEMBER TO MARCH, INCLUSIVE)
2/ MDQ REDUCES TO 18,126 DTH EFFECTIVE 5/1/2003

NOTE: ALL AGREEMENTS WITH MDQ OF 271 OR 272 DTH (TOTAL OF 25,000 DTH/DAY) WILL BE REPLACED BY AGREEMENTS OF 367 OR 368 DTH EFFECTIVE (TOTAL OF 25,000 DTH/DAY) FOR THE PERIOD 11/1/2003 TO 8/31/2005

Trailblazer Pipeline Company
Docket No. RP03-162-000
Company Response to Staff Data Request (KJP-1), Item No. 17

Exhibit No. S-11
Page 29 of 40 pages.
Schedule No. 16, Page 5 of 5 pages.

Trailblazer Pipeline Company
Docket No. RP03-162-000
On the Use of Iowa Curves

Iowa curves 1/ are useful tools in establishing average service lives (ASL) and applicable retirement patterns for each account, and from them determining each account's average remaining life (ARL). Iowa curves are used to account for the normal retirements that occur over the life of an account so that the account will be fully accrued when its useful life is over. Normal retirements must be considered to insure that the account is not under-accrued when its useful life is over. This is because the depreciation rates are applied to the gross plant to arrive at the annual depreciation expense for each account. When retirements are made from the gross plant, the annual depreciation expense would decrease, with the result that the investment would not be fully recovered at the end of its life were these retirements not taken into account in calculating the depreciation rate.

An Iowa curve, fitted to a particular account, predicts the ASL and retirement pattern of that account. The ASL is the average length of time that all units of a group are expected to last when they are new. The retirement pattern shows how much of the group will be retired each year as the group ages. The ARL, which is of particular importance

1/ The Iowa curves were developed at the Iowa State College Engineering Experiment Station by extensive observation and classification of ages at which industrial property has been retired.

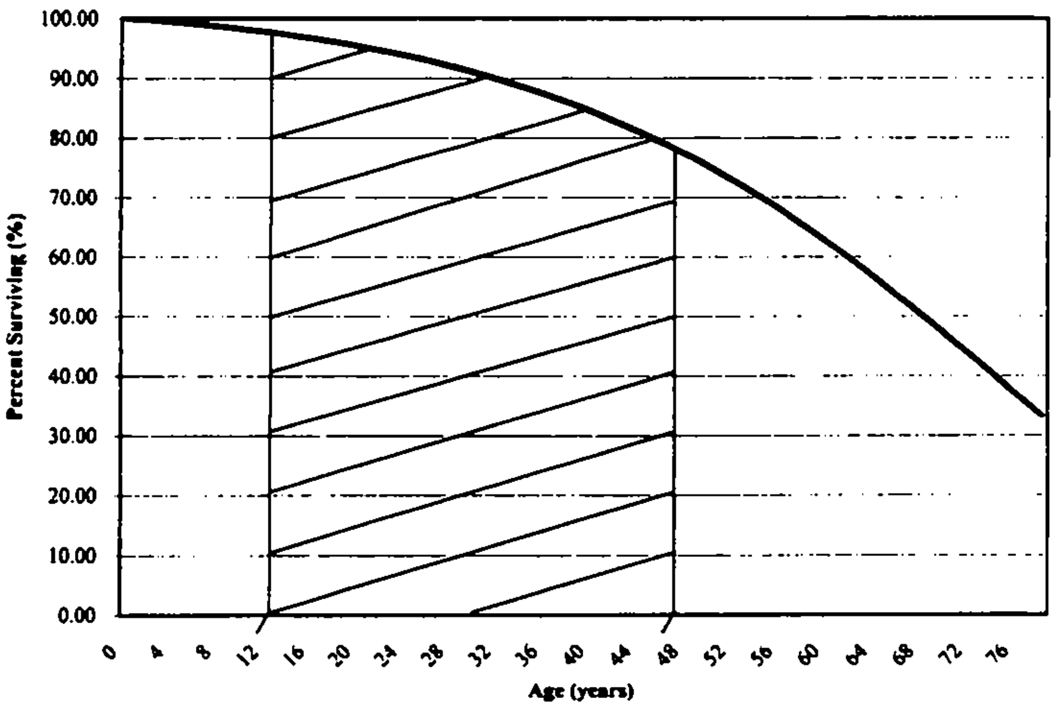
Trailblazer Pipeline Company
Docket No. RP03-162-000
On the Use of Iowa Curves

in the calculation of the depreciation rate, is determined from the useful life of the facility and from each account's Iowa curve.

Ideally, Iowa curves are chosen for each account by fitting them to vintaged installation and retirement data. In the absence of sufficient retirement data, typical Iowa curves found to be applicable in the staff's analyses of other pipeline companies can be used. A sample Iowa curve including a more detailed definition of terms follows on the next page.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Example of an Iowa Curve

Iowa-Type Survivor Curve
65-year Average Service Life, R2 Curve, 35-year Truncation



Example: Remaining Economic Life = 35 years; Age = 12 years; Average Remaining Life = 32 years

AVERAGE SERVICE LIFE (ASL) is the average expected life of all units of a group when new. The ASL equals the area under the survivor curve, from age zero to the maximum age, divided by the original group.

AVERAGE AGE is the average length of time that the units of a group have been in service. The older the units are, the shorter their remaining life is expected to be.

AVERAGE REMAINING LIFE (ARL) is the average life that remains to the surviving units of a group, at a given age for the group. The ARL is reported in years. It is calculated by obtaining the area under the survivor curve from an observation age to a maximum age and dividing this area by the ordinate at the observation age.

Trailblazer Pipeline Company
RP03-162-000
Determination of Average Remaining Life and Percent Surviving at Truncation

Function/Account	Survivor Curve	12/31/02 Gross Plant	12/31/02 Average Age	12/31/02 Average Remaining Life	12/31/02 Percent Surviving at Trunc.
Existing Plant					
Intangible					
Transmission					
all plant less comp.	65 R2	271,957,706	20.06	30.3	69.01
compressor sta. equip.	30 R3	11,146,322	5.94	24.3	11.37
Total		283,104,028		30.1	66.74
Expansion Plant (see kjp-1, 3)					
Transmission					
compressor sta. equip.	30 R3	47,109,741	0.59	28.1	31.98
Existing and Expansion					
Transmission			16.77	29.8	61.78

Trailblazer Pipeline Company
Docket No. RP03-162-000
Factors in Depreciation Calculation for Transmission Facilities

Trailblazer Pipeline Company
RP03-162-000
Factors in the Depreciation Calculation for Transmission Facilities
remaining economic life = 35 years from 12/31/2001 or
34 years from 12/31/02

Function/Account	(1) 3/31/03 Gross Plant ($)	(2) 3/31/03 Accrued Depreciation ($)	(3) Percent Net Plant (%)	(4) Company Existing Rate (%)	(5) Company Proposed Rate (%)	(6) Staff Recommended Rate (%)	(7) Survivor Curve	(8) at 3/31/03 Average Remaining Life (yr)	(9) Staff Calculated Depreciation Rate (%)	(10) at 12/31/02 Percent Surviving at Trunc. (%)	(11) Difference in Annual Expense ($)
Existing Plant											
Intangible	90,746	23,384	74.23	33.30	0.00	0.00	--	33.75	2.20	--	0
Transmission	283,200,082	205,629,876	27.39	3.60	2.90	0.90	65 R2, 30 R3	29.85	0.92	66.74	(5,664,002)
General	174,377	7,039	95.96	3.60	10.00	20.00			19.92		17,438
Expansion Plant											
Transmission compressor sta. equip	47,109,741	2,197,990	95.33	5.00	7.00	3.40	30 R3	27.85	3.42	31.98	(1,695,951)
Existing and Expansion											
Transmission	330,309,823	207,827,866	37.08	--	3.48 (calculated)	1.25	--	29.55	1.25	61.78	(7,381,611)

Notes: rates in column (6) rounded to nearest 0.05 percent

average remaining lives in column (8) adjusted by 0.25 year to bring date from 12/31/02 to 3/31/03

Exhibit No. S-11
Page 34 of 40 pages.
Schedule No. 19, Page 1 of 1 pages.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Company Response to Staff Data Request (KJP-1), Item No. 4

TRAILBLAZER PIPELINE COMPANY

Data Response Form for
Docket No. RP03-162-000

Requesting Party: FERC Staff

Data Request Reference: KJP-1

Data Request No.: 4

Question:

With respect to General Plant, please provide the major items in each account and the approximate dollar amount of each major item.

Response:

Account 391.01, Office Furniture and Equipment, $3,551, Fax Machines;

Account 391.03, Computers, $55,556, to include Mapping and Records, $42,514, Digitization of location structures, $10,653;

Account 392, Vehicles-Light Trucks, $103,487, includes 3 Pick-up trucks, $96,678, ATV and Trailer $6,829;

Account 394,397,398. Tools and Work Equipment, $11,783, includes Safety Climbing Devices, $5,121, Phone System, $4087.

Prepared by: Geoffrey E. Simmons

Trailblazer Pipeline Company
Docket No. RP03-162-000
Calculation of Depreciation Rate for General Plant

Account No.	Name	Gross Plant (12/31/02)	Estimate of ASL		Weighting Calculation	Contents of Account
391.1	office furn. & equip.	3,551	5		17,755	fax machines
391.3	computers	55,556	4		222,224	mapping and records, digitization of location structures
392.2, 392.5	vehicles-light trucks	103,487	5		517,435	3 pick-up trucks, ATV and trailer
394, 395, 398	tools and work equip.	11,783	10		117,830	safety climbing devices, phone system
	total	174,377			875,244	
	weighted-average ASL		5.02	yr.		
	ASL rate (100 / 5.02)		19.92	%		
	Recommended Rate		20.00	%		

Trailblazer Pipeline Company
Docket No. RP03-162-000
Calculation of Depreciation Rate for General Plant

Exhibit No. S-11
Page 36 of 40 pages.
Schedule No. 21, Page 1 of 1 pages.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Correction of Mr. Simmons' UOP Calculation With Respect to His Treatment of Reserves
Exhibit TPC-56, Schedule B, Uncorrected

	(1)	(2)	(3)	(4)	(5)	(6)
Row	Year	Beginning Supply Base	Future Reserve Additions	Annual Supply Base	Future Annual Deliverability	Production Reserve Ratio
				(2) + (3)		(5) / (4)
1	2003	4,412	474	4,886	600	0.1228
2	2004	4,286	459	4,745	604	0.1273
3	2005	4,141	445	4,586	600	0.1308
4	2006	3,986	431	4,417	586	0.1327
5	2007	3,831	418	4,249	563	0.1325
6	2008	3,686	397	4,083	537	0.1315
7	2009	3,546	384	3,930	518	0.1318
8	2010	3,412	373	3,785	498	0.1316
9	2011	3,287	347	3,634	480	0.1321
10	2012	3,154	336	3,490	464	0.1330
11	2013	3,026	319	3,345	446	0.1333
12	2014	2,899	308	3,207	431	0.1344
13	2015	2,776	299	3,075	415	0.1350
14	2016	2,660	289	2,949	399	0.1353
15	2017	2,550	280	2,830	385	0.1360
16	2018	2,445	271	2,716	372	0.1370
17	2019	2,344	253	2,597	358	0.1379
18	2020	2,239	245	2,484	346	0.1393
19	2021	2,138	237	2,375	335	0.1411
20	2022	2,040	229	2,269	322	0.1419
Total			6,794			

Trailblazer Pipeline Company
Docket No. RP03-162-000
Correction of Mr. Simmons' UOP Calculation with Respect to His Treatment of Reserves

Trailblazer Pipeline Company
Docket No. RP03-162-000
Correction of Mr. Simmons' UOP Calculation
Exhibit TPC-56, Schedule C, Uncorrected

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Row	Year	Depreciable Plant	Plant Additions	Accumulated Depreciation Reserve	Net Plant Balance	Production Reserve Ratio	Calculated Depreciation Expense	Avg. Annual Depreciation Expense	Average Plant Balance	Indicated Avg. Depreciation Rate	Interim Retirement Rate	Average Depreciation Rate
					(2) + (3) - (4)		(5) x (6)			(8) / (9)		(10 + (11)
1	2003	283,169.7	--	203,434.8	79,734.9	0.1228	9,791.4	9,791.4	283,169.7	3.46	0.37	3.83
2	2004	283,169.7	--	213,226.2	69,943.5	0.1273	8,903.8	9,347.6	283,169.7	3.30	0.38	3.68
3	2005	283,169.7	--	222,130.8	61,039.7	0.1308	7,984.0	8,893.1	283,169.7	3.14	0.39	3.53
4	2006	283,169.7	--	230,114.0	53,055.7	0.1327	7,040.5	8,429.9	283,169.7	2.98	0.40	3.38
5	2007	283,169.7	--	237,154.5	46,015.2	0.1325	6,097.0	7,963.3	283,169.7	2.81	0.40	3.21
6	2008	283,169.7	--	243,251.5	39,918.2	0.1315	5,249.2	7,511.0	283,169.7	2.65	0.41	3.06
7	2009	283,169.7	--	248,500.8	34,668.9	0 1318	4,569.4	7,090.8	283,169.7	2.50	0.42	2.92
8	2010	283,169.7	--	253,070.1	30,099.6	0.1316	3,961.1	6,699.6	283,169.7	2.37	0.43	2.80
9	2011	283,169.7	--	257,031.2	26,138.5	0.1321	3,452.9	6,338.8	283,169.7	2.24	0.44	2.68
10	2012	283,169.7	--	260,484.1	22,685.6	0.1330	3,017.2	6,006.7	283,169.7	2.12	0.45	2.57
11	2013	283,169.7	--	263,501.3	19,668.4	0.1333	2,621.8	5,698.9	283,169.7	2.01	0.46	2.47
12	2014	283,169 7	--	266,123.1	17,046.6	0.1344	2,291.1	5,414.9	283,169.7	1.91	0.47	2.38
13	2015	283,169.7	--	268,414.2	14,755.5	0.1350	1,992.0	5,151.6	283,169.7	1.82	0.48	2.30
14	2016	283,169.7	--	270,406.2	12,763.5	0.1353	1,726.9	4,907.0	283,169.7	1.73	0.49	2.22
15	2017	283,169 7	--	272,133.1	11,036.6	0.1360	1,501.0	4,680.0	283,169.7	1.65	0.50	2.15
16	2018	283,169 7	--	273,634.1	9,535.6	0.1370	1,306.4	4,469.1	283,169.7	1.58	0.51	2.09
17	2019	283,169 7	--	274,940.4	8,229.3	0.1379	1,134.8	4,273.0	283,169.7	1.51	0.52	2.03
18	2020	283,169 7	--	276,075.3	7,094.4	0.1393	988.3	4,090.5	283,169.7	1.44	0.53	1.97
19	2021	283,169.7	--	277,063.5	6,106.2	0.1411	861.6	3,920.5	283,169.7	1.38	0.54	1.92
20	2022	283,169 7	--	277,925.1	5,244.6	0.1419	744.2	3,761.7	283,169.7	1.33	0.55	1.88

Exhibit No. S-11
Page 38 of 40 pages.
Schedule No. 22, Page 2 of 4 pages.

Trailblazer Pipeline Company
Docket No. RP03-162-000
Correction of Mr. Simmons' UOP Calculation With Respect to His Treatment of Reserves
Exhibit TPC-56, Schedule B. Corrected

	(1)	(2)	(3)	(4)	(5)	(6)
Row	Year	Beginning Supply Base	Future Reserve Additions	Annual Supply Base	Future Annual Deliverability	Production Reserve Ratio
				$(2)_{2003} + \Sigma(3)$ $(4)_{n-1} - (5)_{n-1}$		(5) / (4)
1	2003	4,412	474	11,206	600	0.0535
2	2004	4,286	459	10,606	604	0.0569
3	2005	4,141	445	10,002	600	0.0600
4	2006	3,986	431	9,402	586	0.0623
5	2007	3,831	418	8,816	563	0.0639
6	2008	3,686	397	8,253	537	0.0651
7	2009	3,546	384	7,716	518	0.0671
8	2010	3,412	373	7,198	498	0.0692
9	2011	3,287	347	6,700	480	0.0716
10	2012	3,154	336	6,220	464	0.0746
11	2013	3,026	319	5,756	446	0.0775
12	2014	2,899	308	5,310	431	0.0812
13	2015	2,776	299	4,879	415	0.0851
14	2016	2,660	289	4,464	399	0.0894
15	2017	2,550	280	4,065	385	0.0947
16	2018	2,445	271	3,680	372	0.1011
17	2019	2,344	253	3,308	358	0.1082
18	2020	2,239	245	2,950	346	0.1173
19	2021	2,138	237	2,604	335	0.1286
20	2022	2,040	229	2,269	322	0.1419
Total			6,794			

Trailblazer Pipeline Company
Docket No. RP03-162-000
Correction of Mr. Simmons' UOP Calculation
Exhibit TPC-56, Schedule C, Corrected

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Row	Year	Depreciable Plant	Plant Additions	Accumulated Depreciation Reserve	Net Plant Balance	Production Reserve Ratio	Calculated Depreciation Expense	Avg. Annual Depreciation Expense	Average Plant Balance	Indicated Avg. Depreciation Rate	Interim Retirement Rate	Average Depreciation Rate
					(2) + (3) - (4)		(5) x (6)			(8) / (9)		(10 + (11)
1	2003	283,169.7	--	203,434.8	79,734.9	0.0535	4,269.2	4,269.2	283,169.7	1.51	0.37	1.88
2	2004	283,169.7	--	207,704.0	75,465.7	0.0569	4,297.7	4,283.5	283,169.7	1.51	0.38	1.89
3	2005	283,169.7	--	212,001.7	71,168.0	0.0600	4,269.2	4,278.7	283,169.7	1.51	0.39	1.90
4	2006	283,169.7	--	216,270.9	66,898.8	0.0623	4,169.6	4,251.4	283,169.7	1.50	0.40	1.90
5	2007	283,169.7	--	220,440.5	62,729.2	0.0639	4,006.0	4,202.3	283,169.7	1.48	0.40	1.88
6	2008	283,169.7	--	224,446.5	58,723.2	0.0651	3,821.0	4,138.8	283,169.7	1.46	0.41	1.87
7	2009	283,169.7	--	228,267.5	54,902.2	0.0671	3,685.8	4,074.1	283,169.7	1.44	0.42	1.86
8	2010	283,169.7	--	231,953.2	51,216.5	0.0692	3,543.5	4,007.7	283,169.7	1.42	0.43	1.85
9	2011	283,169.7	--	235,496.7	47,673.0	0.0716	3,415.4	3,941.9	283,169.7	1.39	0.44	1.83
10	2012	283,169.7	--	238,912.1	44,257.6	0.0746	3,301.5	3,877.9	283,169.7	1.37	0.45	1.82
11	2013	283,169.7	--	242,213.6	40,956.1	0.0775	3,173.5	3,813.8	283,169.7	1.35	0.46	1.81
12	2014	283,169.7	--	245,387.1	37,782.6	0.0812	3,066.7	3,751.6	283,169.7	1.32	0.47	1.79
13	2015	283,169.7	--	248,453.8	34,715.9	0.0851	2,952.9	3,690.1	283,169.7	1.30	0.48	1.78
14	2016	283,169.7	--	251,406.7	31,763.0	0.0894	2,839.0	3,629.3	283,169.7	1.28	0.49	1.77
15	2017	283,169.7	--	254,245.7	28,924.0	0.0947	2,739.4	3,570.0	283,169.7	1.26	0.50	1.76
16	2018	283,169.7	--	256,985.1	26,184.6	0.1011	2,646.9	3,512.3	283,169.7	1.24	0.51	1.75
17	2019	283,169.7	--	259,632.0	23,537.7	0.1082	2,547.3	3,455.6	283,169.7	1.22	0.52	1.74
18	2020	283,169.7	--	262,179.3	20,990.4	0.1173	2,461.9	3,400.4	283,169.7	1.20	0.53	1.73
19	2021	283,169.7	--	264,641.3	18,528.4	0.1286	2,383.7	3,346.8	283,169.7	1.18	0.54	1.72
20	2022	283,169.7	--	267,024.9	16,144.8	0.1419	2,291.2	3,294.1	283,169.7	1.16	0.55	1.71

Trailblazer Pipeline Company
Docket No. RP03-162-000
Correction of Mr. Simmons' UOP Calculation with Respect to His Treatment of Reserves

Exhibit No. S-11
Page 40 of 40 pages.
Schedule No. 22, Page 4 of 4 pages.

EXHIBIT NO. S-12

FEDERAL ENERGY REGULATORY COMMISSION
OFFICE OF ADMINISTRATIVE LITIGATION

TRAILBLAZER PIPELINE COMPANY
DOCKET NO. RP03-162-000

WORKPAPERS OF

COMMISSION STAFF WITNESS

KEVIN J. PEWTERBAUGH

ON

DEPRECIATION

MAY 22, 2003

WASHINGTON, D.C. 20426

Trailblazer Pipiline Company
Docket No. RP03-162-000
Historical Annual Production and Remaining Reserve Data
(Dry Gas in Bcf)

Domestic Supply Area
(Colorado, Wyoming)

	Dry Production			
Year	Colorado	Wyoming	Total	Cum.
1977	174	315	489	13,357
1978	167	329	496	13,853
1979	156	355	511	14,364
1980	163	416	579	14,943
1981	165	423	588	15,531
1982	196	391	587	16,118
1983	156	414	570	16,688
1984	171	484	655	17,343
1985	166	433	599	17,942
1986	188	402	590	18,532
1987	159	456	615	19,147
1988	188	510	698	19,845
1989	220	591	811	20,656
1990	229	583	812	21,468
1991	282	639	921	22,389
1992	320	714	1,034	23,423
1993	387	713	1,100	24,523
1994	447	780	1,227	25,750
1995	514	806	1,320	27,070
1996	540	782	1,322	28,392
1997	562	891	1,453	29,845
1998	676	838	1,514	31,359
1999	719	1,213	1,932	33,291
2000	759	1,070	1,829	35,120
2001	882	1,286	2,168	37,288

	Dry Remaining Reserves		
Year	Colorado	Wyoming	Total
1977	2,512	6,305	8,817
1978	2,765	7,211	9,976
1979	2,608	7,526	10,134
1980	2,922	9,100	12,022
1981	2,961	9,307	12,268
1982	3,314	9,758	13,072
1983	3,148	10,227	13,375
1984	2,943	10,482	13,425
1985	2,881	10,617	13,498
1986	3,027	9,756	12,783
1987	2,942	10,023	12,965
1988	3,535	10,308	13,843
1989	4,274	10,744	15,018
1990	4,555	9,944	14,499
1991	5,767	9,941	15,708
1992	6,198	10,826	17,024
1993	6,722	10,933	17,655
1994	6,753	10,879	17,632
1995	7,256	12,166	19,422
1996	7,710	12,320	20,030
1997	6,828	13,562	20,390
1998	7,881	13,650	21,531
1999	8,987	14,226	23,213
2000	10,428	16,158	26,586
2001	12,527	18,398	30,925

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Report (1977-1998)*, *Energy Information Administration.*

Wet Production										
	d/w		d/w		d/w	cum prod. wet		cum. prod. dry		
Colorado		Wyoming		Total		Colorado	Wyoming	Colorado	Wyoming	Total
not reported										
not reported										
171	0.9123	370	0.9595	542	0.9430					
178	0.9157	430	0.9674	609	0.9509					
180	0.9167	439	0.9636	620	0.9485					
211	0.9289	407	0.9607	619	0.9484					
167	0.9341	434	0.9539	602	0.9469					
183	0.9344	508	0.9528	692	0.9466					
178	0.9326	458	0.9454	637	0.9404					
199	0.9447	428	0.9393	628	0.9396					
169	0.9408	481	0.9480	651	0.9448					
200	0.9400	539	0.9462	740	0.9433	6,404	14,620	5,956	13,889	19,845
avg. =	0.9300		0.9537							
use =	0.93		0.95							

T6

T6 supply areas (Harrell)

Wyoming

E Powder River < ≤2000 / >2000

Bighorn

Green River

Wind River

Washakie

Red Desert

Hanna

W rest of Wyoming

Colorado

E Denver

Piceance

W rest of Colorado

Colorado excluded (southern CO)

Raton

San Juan

Paradox

Utah

W Uinta Basin

use WY, CO

* E-Rockies (E)

W-Rockies (W)

Other WY = all but Powder R. Basin

Other CO = northern 2/3 of CO, excl. Denver

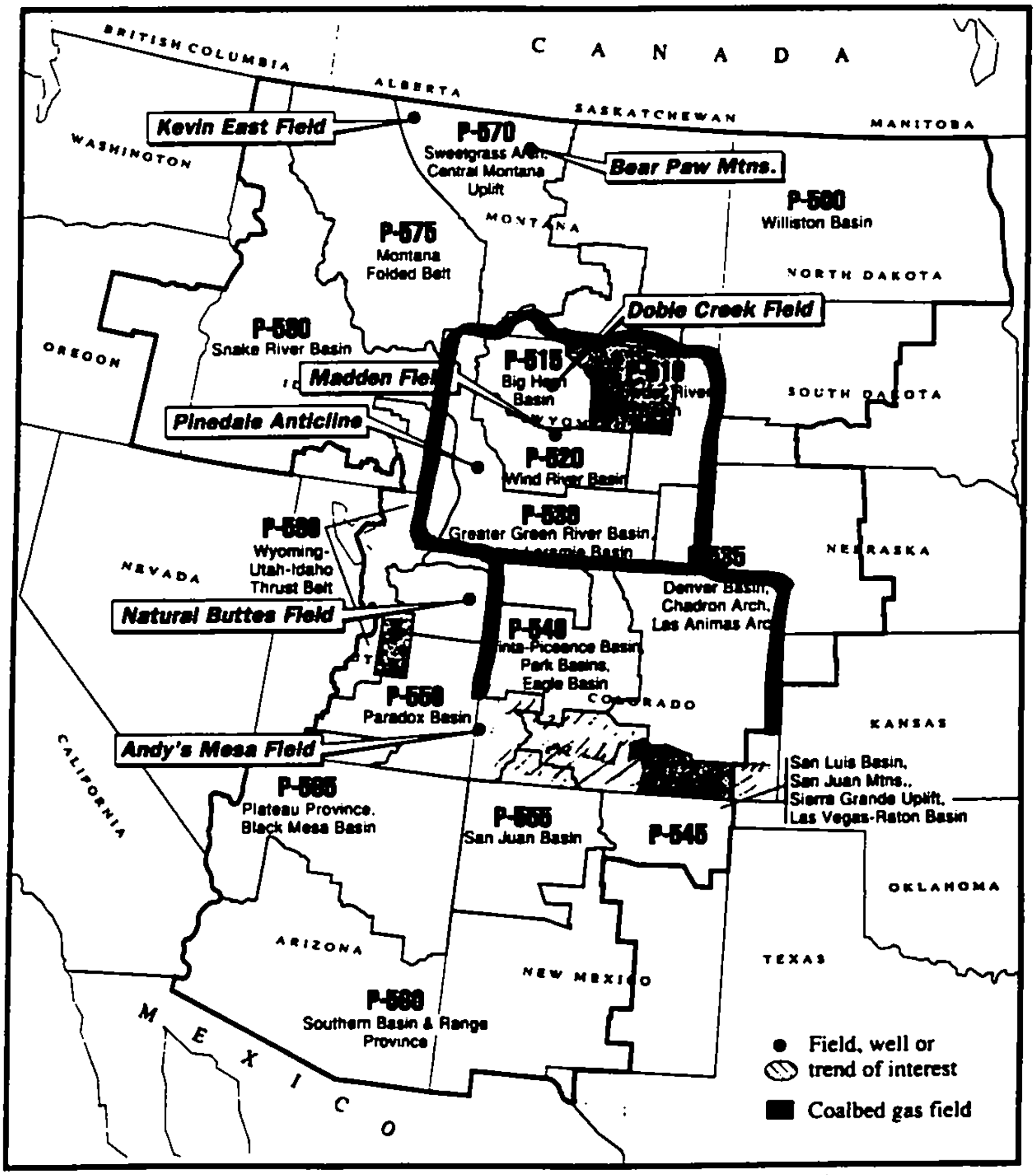


Figure 60. Geologic provinces and selected field activities in the Rocky Mountain Area.

TRAILBLAZER PIPELINE COMPANY

**Data Response Form for
Docket No. RP03-162-000**

Requesting Party: FERC Staff

Data Request Reference: KJP-1

Data Request No.: 3

Question:

For depreciable, jurisdictional plant, and amortizable plant as of December 31, 2001, and as of December 31, 2002, provide, broken out consistent with the FERC Form No. 2: the plant in service, the accumulated reserve for depreciation or amortization, and the average age of the plant. Update this information through April 30, 2003, the end of the test period, as information becomes available.

Response:

See the attached schedules for the plant and accumulated reserve balances requested.

The average age of the Existing System Facilities transmission plant is approximately 19.5 years as of December 31, 2002. The average age of the Expansion 2002 System Facilities transmission plant is approximately .59 years at December 31, 2002. The average age of the Existing System Facilities transmission plant is approximately 18.5 years at December 31, 2001. The Expansion 2002 System was not in service at December 31, 2001. See the attached schedules for average age calculations.

Prepared by: Geoffrey E. Simmons

Data Request Reference: KJP-1, #3

TRAILBLAZER PIPELINE COMPANY
Account 101 - Gas Plant in Service

	Existing System	Account Number	Dec-01 $	Aug-02 $	Sep-02 $	Oct-02 $	Nov-02 $	Dec-02 $
	Intangible Plant							
1	Miscellaneous Intangible Plant	303	90,746	90,746	90,746	90,746	90,746	90,746
	Transmission Plant							
2	Land and Land Rights	365.1	724,062	724,062	724,062	724,062	724,062	724,062
3	Rights of Way	365.2	3,672,077	3,672,077	3,672,077	3,672,077	3,672,313	3,672,313
4	Structures and Improvements	366	1,801,395	1,801,395	1,801,395	1,801,395	1,801,395	1,831,502
5	Mains	367	261,725,687	261,725,687	261,725,687	261,725,687	261,903,037	261,903,037
6	Compressor Station Equipment	368	11,146,322	11,146,322	11,146,322	11,146,322	11,146,322	11,146,322
7	Measuring and Regulating Station Equipment	369	3,596,587	3,596,587	3,596,587	3,596,587	3,602,438	3,602,438
8	Communication Equipment	370	948,417	948,417	948,417	948,417	948,417	948,417
9	Total Transmission Plant		283,614,547	283,614,547	283,614,547	283,614,547	283,797,983	283,828,090
	General Plant							
10	Office Furniture and Equipment	391.1	9,971	7,581	7,581	7,581	3,551	3,551
11	Computers	391.3	-	2,389	2,389	2,389	55,556	55,556
12	Vehicles-Light Trucks	392.2, 392.5	-	96,658	96,658	96,658	103,487	103,487
13	Tools and Work Equipment	394, 397,398	2,067	2,067	2,067	2,067	6,662	11,783
14	Total General Plant		12,038	108,695	108,695	108,695	169,256	174,377
15	Total Gas Plant in Service - Existing System		283,717,331	283,813,988	283,813,988	283,813,988	284,057,985	284,093,213
	Expansion 2002 System							
16	Compressor Station Equipment	368	-	45,299,764	45,299,764	46,992,013	47,109,741	47,109,741
17	Total Gas Plant in Service - Expansion 2002 System		-	45,299,764	45,299,764	46,992,013	47,109,741	47,109,741
18	Total Gas Plant in Service		283,717,331	329,113,752	329,113,752	330,806,001	331,167,727	331,202,955

Data Request Reference: KJP-1, #3

TRAILBLAZER PIPELINE COMPANY
Accumulated Reserve for Depreciation, Depletion and Amortization

		Dec-01 $	Aug-02 $	Sep-02 $	Oct-02 $	Nov-02	Dec-02
	Existing System						
1	Account 108 - Accumulated Provisions for Depreciation of Gas Plant in Service						
2	Transmission:						
3	Onshore	(193,254,048)	(200,029,869)	(200,868,011)	(201,684,889)	(202,553,924)	(203,094,870)
4	General Plant	(849)	(4,222)	(4,756)	(5,291)	(1,903)	(2,626)
5	Total Account 108	(193,254,897)	(200,034,091)	(200,872,767)	(201,690,180)	(202,555,826)	(203,097,496)
6	Account 111 - Accumulated Provisions for Amortization						
7	Intangible	(19,423)	(21,601)	(21,873)	(22,145)	(22,418)	(22,690)
8	Total Accumulated Reserve for Depreciation, Depletion and Amortization - Existing System	(193,274,320)	(200,055,692)	(200,894,640)	(201,712,325)	(202,578,244)	(203,120,186)
	Expansion 2002 System						
9	Account 108 - Accumulated Provisions for Depreciation of Gas Plant in Service Expansion 2002 System	0	(573,789)	(770,079)	(966,370)	(1,162,660)	(1,665,470)
10	Total Accumulated Reserve for Depreciation, Depletion and Amortization	(193,274,320)	(200,629,481)	(201,664,719)	(202,678,695)	(203,740,904)	(204,785,656)

Exhibit No. S-12
Page 8 of 24 pages.
RP03-162-000, Workpapers

Data Request Reference: KJP-1, #3

Trailblazer Pipeline Company
Plant in Service-By Account
Vintage Basis as of December 31, 2002

Account	Cost	In Service	Current Date	Age in Days	Weighted Cost
Existing System Facilities—Transmission Plant					
36610	30,107.46	31-Dec-02	01-Jan-03	1	30,107
36610	21,305.41	01-Jul-84	01-Jan-03	6,758	143,981,961
36610	33,133.34	01-Jun-84	01-Jan-03	6,788	224,909,112
36610	1,338,657.81	01-Oct-82	01-Jan-03	7,397	9,902,051,821
36620	76,225.75	31-May-00	01-Jan-03	945	72,033,334
36620	7,338.57	01-Nov-93	01-Jan-03	3,348	24,569,532
36620	4,735.23	01-Sep-91	01-Jan-03	4,140	19,603,852
36620	295,277.17	01-Oct-82	01-Jan-03	7,397	2,184,165,226
36630	24,721.44	01-Jun-84	01-Jan-03	6,788	167,809,135
36700	9,415.05	30-Nov-02	01-Jan-03	32	301,282
36700	167,935.13	31-Oct-02	01-Jan-03	62	10,411,978
36700	38.39	30-Jun-00	01-Jan-03	915	35,127
36700	6,900.62	31-May-00	01-Jan-03	945	6,521,086
36700	2,522.09	31-Mar-00	01-Jan-03	1,006	2,537,223
36700	2,535,000.00	01-Feb-97	01-Jan-03	2,160	5,475,600,000
36700	512,540.23	01-Sep-96	01-Jan-03	2,313	1,185,505,552
36700	227,443.21	01-Nov-95	01-Jan-03	2,618	595,446,324
36700	62,298.00	01-May-95	01-Jan-03	2,802	174,558,996
36700	36,274.02	01-Feb-90	01-Jan-03	4,717	171,104,552
36700	216.76	01-Feb-85	01-Jan-03	6,543	1,418,261
36700	7,183.13	01-Dec-83	01-Jan-03	6,971	50,073,599
36700	(3,489.56)	01-Dec-82	01-Jan-03	7,336	(25,599,412)
36700	258,336,948.57	01-Oct-82	01-Jan-03	7,397	1,910,918,408,572
36711	1,811.51	01-Nov-93	01-Jan-03	3,348	6,064,935
36800	0.48	30-Sep-02	01-Jan-03	93	45
36800	10,680,915.74	01-Jul-97	01-Jan-03	2,010	21,468,640,637
36800	259,729.57	01-Jun-97	01-Jan-03	2,040	529,848,323
36800	8,365.39	01-Aug-96	01-Jan-03	2,344	19,608,474
36800	(195,038.67)	01-Nov-95	01-Jan-03	2,618	(510,611,238)
36800	50,604.17	01-Sep-94	01-Jan-03	3,044	154,039,093
36800	12,775.50	01-Apr-87	01-Jan-03	5,754	73,510,227
36800	30,552.53	01-Dec-83	01-Jan-03	6,971	212,981,687
36800	3,677.19	01-Oct-83	01-Jan-03	7,032	25,858,000
36800	294,740.56	01-Oct-82	01-Jan-03	7,397	2,180,195,922
36901	9,654.47	30-Nov-02	01-Jan-03	32	308,943
36901	39,237.20	31-Oct-02	01-Jan-03	62	2,432,706
36901	14,505.51	01-Feb-95	01-Jan-03	2,891	41,935,429
36901	15,116.97	01-Nov-93	01-Jan-03	3,348	50,611,618
36901	12,374.53	01-Sep-91	01-Jan-03	4,140	51,230,554
36901	5,575.27	01-Aug-85	01-Jan-03	6,362	35,469,868
36901	3,505,973.57	01-Oct-82	01-Jan-03	7,397	25,933,686,497
37001	20,382.98	01-Feb-85	01-Jan-03	6,543	133,365,838
37001	30,041.13	01-Dec-84	01-Jan-03	6,605	198,421,664
37001	262,002.01	01-Oct-82	01-Jan-03	7,397	1,938,028,868
37002	7,473.76	01-Aug-93	01-Jan-03	3,440	25,709,734
37002	2,178.16	01-Jun-91	01-Jan-03	4,232	9,217,973
37002	4,991.62	01-Jun-90	01-Jan-03	4,597	22,946,477
37002	36,197.32	01-Dec-89	01-Jan-03	4,779	172,986,992
37002	11,888.07	01-Apr-89	01-Jan-03	5,023	59,713,776
37002	7,552.00	01-Mar-85	01-Jan-03	6,515	49,201,280
37002	561,549.69	01-Oct-82	01-Jan-03	7,397	4,153,783,057
37002	2,149.77	01-Jul-82	01-Jan-03	7,489	16,099,628
37002	2,010.81	01-Jun-82	01-Jan-03	7,519	15,119,280
	$ 279,431,717				$ 1,988,375,883,505
					19.50
Expansion 2002 System Facilities—Transmission Plant					
36800	47,109,740.93	31-May-02	01-Jan-03	215	10,128,594,300
					0.59

Data Request Reference: KJP-1, #3

Trailblazer Pipeline Company
Plant in Service-By Account
Vintage Basis as of December 31, 2002

Account	Cost	In Service	Current Date	Age in Days	Weighted Cost
Existing System Facilities					
36610	21,305.41	01-Jul-84	01-Jan-02	6,393	136,205,486
36610	33,133.34	01-Jun-84	01-Jan-02	6,423	212,815,443
36610	1,338,657.81	01-Oct-82	01-Jan-02	7,032	9,413,441,720
36620	76,225.75	31-May-00	01-Jan-02	580	44,210,935
36620	7,338.57	01-Nov-93	01-Jan-02	2,983	21,890,954
36620	4,735.23	01-Sep-91	01-Jan-02	3,775	17,875,493
36620	295,277.17	01-Oct-82	01-Jan-02	7,032	2,076,389,059
36630	24,721.44	01-Jun-84	01-Jan-02	6,423	158,785,809
36700	38.39	30-Jun-00	01-Jan-02	550	21,115
36700	6,900.62	31-May-00	01-Jan-02	580	4,002,360
36700	2,522.09	31-Mar-00	01-Jan-02	641	1,616,660
36700	2,535,000.00	01-Feb-97	01-Jan-02	1,795	4,550,325,000
36700	512,540.23	01-Sep-96	01-Jan-02	1,948	998,428,368
36700	227,443.21	01-Nov-95	01-Jan-02	2,253	512,429,552
36700	62,298.00	01-May-95	01-Jan-02	2,437	151,820,226
36700	36,274.02	01-Feb-90	01-Jan-02	4,352	157,864,535
36700	216.76	01-Feb-85	01-Jan-02	6,178	1,339,143
36700	7,183.13	01-Dec-83	01-Jan-02	6,606	47,451,757
36700	(3,489.56)	01-Dec-82	01-Jan-02	6,971	(24,325,723)
36700	258,336,948.57	01-Oct-82	01-Jan-02	7,032	1,816,625,422,344
36711	1,811.51	01-Nov-93	01-Jan-02	2,983	5,403,734
36800	10,680,915.74	01-Jul-97	01-Jan-02	1,645	17,570,106,392
36800	259,729.57	01-Jun-97	01-Jan-02	1,675	435,047,030
36800	8,365.39	01-Aug-96	01-Jan-02	1,979	16,555,107
36800	(195,038.67)	01-Nov-95	01-Jan-02	2,253	(439,422,124)
36800	50,604.17	01-Sep-94	01-Jan-02	2,679	135,568,571
36800	12,775.50	01-Apr-87	01-Jan-02	5,389	68,847,170
36800	30,552.53	01-Dec-83	01-Jan-02	6,606	201,830,013
36800	3,677.19	01-Oct-83	01-Jan-02	6,667	24,515,826
36800	294,740.56	01-Oct-82	01-Jan-02	7,032	2,072,615,618
36901	14,505.51	01-Feb-95	01-Jan-02	2,526	36,640,918
36901	15,116.97	01-Nov-93	01-Jan-02	2,983	45,093,922
36901	12,374.53	01-Sep-91	01-Jan-02	3,775	46,713,851
36901	5,575.27	01-Aug-85	01-Jan-02	5,997	33,434,894
36901	3,505,973.57	01-Oct-82	01-Jan-02	7,032	24,654,006,144
37001	20,382.98	01-Feb-85	01-Jan-02	6,178	125,926,050
37001	30,041.13	01-Dec-84	01-Jan-02	6,240	187,456,651
37001	262,002.01	01-Oct-82	01-Jan-02	7,032	1,842,398,134
37002	7,473.76	01-Aug-93	01-Jan-02	3,075	22,981,812
37002	2,178.16	01-Jun-91	01-Jan-02	3,867	8,422,945
37002	4,991.62	01-Jun-90	01-Jan-02	4,232	21,124,536
37002	36,197.32	01-Dec-89	01-Jan-02	4,414	159,774,970
37002	11,888.07	01-Apr-89	01-Jan-02	4,658	55,374,630
37002	7,552.00	01-Mar-85	01-Jan-02	6,150	46,444,800
37002	561,549.69	01-Oct-82	01-Jan-02	7,032	3,948,817,420
37002	2,149.77	01-Jul-82	01-Jan-02	7,124	15,314,961
37002	2,010.81	01-Jun-82	01-Jan-02	7,154	14,385,335
	$ 279,175,367				$ 1,886,463,389,546
					18.51

Account	Cost	In Service	Current Date	Age in Days	Weighted Cost
Expansion 2002 System Facilities					
36800	-	01-Jan-02	01-Jan-02	-	-

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existing plant, all

Account	plant	in service date	current date	age in days	weighted cost
36610	30,107.46	12/31/2002	1/1/2003	1	30,107
36610	21,305.41	7/1/1984	1/1/2003	6758	143,981,961
36610	33,133.34	6/1/1984	1/1/2003	6788	224,909,112
36610	1,338,657.81	10/1/1982	1/1/2003	7397	9,902,051,821
36620	76,225.75	5/31/2000	1/1/2003	945	72,033,334
36620	7,338.57	11/1/1993	1/1/2003	3348	24,569,532
36620	4,735.23	9/1/1991	1/1/2003	4140	19,603,852
36620	295,277.17	10/1/1982	1/1/2003	7397	2,184,165,226
36630	24,721.44	6/1/1984	1/1/2003	6788	167,809,135
36700	9,415.05	11/30/2002	1/1/2003	32	301,282
36700	167,935.13	10/31/2002	1/1/2003	62	10,411,978
36700	38.39	6/30/2000	1/1/2003	915	35,127
36700	6,900.62	5/31/2000	1/1/2003	945	6,521,086
36700	2,522.09	3/31/2000	1/1/2003	1006	2,537,223
36700	2,535,000.00	2/1/1997	1/1/2003	2160	5,475,600,000
36700	512,540.23	9/1/1996	1/1/2003	2313	1,185,505,552
36700	227,443.21	11/1/1995	1/1/2003	2618	595,446,324
36700	62,298.00	5/1/1995	1/1/2003	2802	174,558,996
36700	36,274.02	2/1/1990	1/1/2003	4717	171,104,552
36700	216.76	2/1/1985	1/1/2003	6543	1,418,261
36700	7,183.13	12/1/1983	1/1/2003	6971	50,073,599
36700	(3,489.56)	12/1/1982	1/1/2003	7336	(25,599,412)
36700	258,336,948.57	10/1/1982	1/1/2003	7397	1,910,918,408,572
36711	1,811.51	11/1/1993	1/1/2003	3348	6,064,935
36800	0.48	9/30/2002	1/1/2003	93	45
36800	10,680,915.74	7/1/1997	1/1/2003	2010	21,468,640,637
36800	259,729.57	6/1/1997	1/1/2003	2040	529,848,323
36800	8,365.39	8/1/1996	1/1/2003	2344	19,608,474
36800	(195,038.67)	11/1/1995	1/1/2003	2618	(510,611,238)
36800	50,604.17	9/1/1994	1/1/2003	3044	154,039,093
36800	12,775.50	4/1/1987	1/1/2003	5754	73,510,227
36800	30,552.53	12/1/1983	1/1/2003	6971	212,981,687
36800	3,677.19	10/1/1983	1/1/2003	7032	25,858,000
36800	294,740.56	10/1/1982	1/1/2003	7397	2,180,195,922
36901	9,654.47	11/30/2002	1/1/2003	32	308,943
36901	39,237.20	10/31/2002	1/1/2003	62	2,432,706
36901	14,505.51	2/1/1995	1/1/2003	2891	41,935,429
36901	15,116.97	11/1/1993	1/1/2003	3348	50,611,616
36901	12,374.53	9/1/1991	1/1/2003	4140	51,230,554
36901	5,575.27	8/1/1985	1/1/2003	6362	35,469,868
36901	3,505,973.57	10/1/1982	1/1/2003	7397	25,933,686,497
37001	20,382.98	2/1/1985	1/1/2003	6543	133,365,838
37001	30,041.13	12/1/1984	1/1/2003	6605	198,421,664
37001	262,002.01	10/1/1982	1/1/2003	7397	1,938,028,868
37002	7,473.76	8/1/1993	1/1/2003	3440	25,709,734
37002	2,178.16	6/1/1991	1/1/2003	4232	9,217,973
37002	4,991.62	6/1/1990	1/1/2003	4597	22,946,477
37002	36,197.32	12/1/1989	1/1/2003	4779	172,986,992
37002	11,888.07	4/1/1989	1/1/2003	5023	59,713,776
37002	7,552.00	3/1/1985	1/1/2003	6515	49,201,280
37002	561,549.69	10/1/1982	1/1/2003	7397	4,153,783,057
37002	2,149.77	7/1/1982	1/1/2003	7489	16,099,628
37002	2,010.81	6/1/1982	1/1/2003	7519	15,119,280
Total	279,431,716.63				1,988,375,883,506
					7115.78452
					19.50

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existing plant, all

Account	plant	in service date	current date	age in days	weighted cost
36610	30,107.46	12/31/2002	1/1/2003	1	30,107
36610	21,305.41	7/1/1984	1/1/2003	6758	143,981,961
36610	33,133.34	6/1/1984	1/1/2003	6788	224,909,112
36610	1,338,657.81	10/1/1982	1/1/2003	7397	9,902,051,821
36620	76,225.75	5/31/2000	1/1/2003	945	72,033,334
36620	7,338.57	11/1/1993	1/1/2003	3348	24,569,532
36620	4,735.23	9/1/1991	1/1/2003	4140	19,603,852
36620	295,277.17	10/1/1982	1/1/2003	7397	2,184,165,226
36630	24,721.44	6/1/1984	1/1/2003	6788	167,809,135
36700	9,415.05	11/30/2002	1/1/2003	32	301,282
36700	167,935.13	10/31/2002	1/1/2003	62	10,411,978
36700	38.39	6/30/2000	1/1/2003	915	35,127
36700	6,900.62	5/31/2000	1/1/2003	945	6,521,086
36700	2,522.09	3/31/2000	1/1/2003	1006	2,537,223
36700	2,535,000.00	2/1/1997	1/1/2003	2160	5,475,600,000
36700	512,540.23	9/1/1996	1/1/2003	2313	1,185,505,552
36700	227,443.21	11/1/1995	1/1/2003	2618	595,446,324
36700	62,298.00	5/1/1995	1/1/2003	2802	174,558,996
36700	36,274.02	2/1/1990	1/1/2003	4717	171,104,552
36700	216.76	2/1/1985	1/1/2003	6543	1,418,261
36700	7,183.13	12/1/1983	1/1/2003	6971	50,073,599
36700	(3,489.56)	12/1/1982	1/1/2003	7336	(25,599,412)
36700	258,336,948.57	10/1/1982	1/1/2003	7397	1,910,918,408,572
36711	1,811.51	11/1/1993	1/1/2003	3348	6,064,935
36800	0.48	9/30/2002	1/1/2003	93	45
36800	10,680,915.74	7/1/1997	1/1/2003	2010	21,468,640,637
36800	259,729.57	6/1/1997	1/1/2003	2040	529,848,323
36800	8,365.39	8/1/1996	1/1/2003	2344	19,608,474
36800	(195,038.67)	11/1/1995	1/1/2003	2618	(510,611,238)
36800	50,604.17	9/1/1994	1/1/2003	3044	154,039,093
36800	12,775.50	4/1/1987	1/1/2003	5754	73,510,227
36800	30,552.53	12/1/1983	1/1/2003	6971	212,981,687
36800	3,677.19	10/1/1983	1/1/2003	7032	25,858,000
36800	294,740.56	10/1/1982	1/1/2003	7397	2,180,195,922
36901	9,654.47	11/30/2002	1/1/2003	32	308,943
36901	39,237.20	10/31/2002	1/1/2003	62	2,432,706
36901	14,505.51	2/1/1995	1/1/2003	2891	41,935,429
36901	15,116.97	11/1/1993	1/1/2003	3348	50,611,616
36901	12,374.53	9/1/1991	1/1/2003	4140	51,230,554
36901	5,575.27	8/1/1985	1/1/2003	6362	35,469,868
36901	3,505,973.57	10/1/1982	1/1/2003	7397	25,933,686,497
37001	20,382.98	2/1/1985	1/1/2003	6543	133,365,838
37001	30,041.13	12/1/1984	1/1/2003	6605	198,421,664
37001	262,002.01	10/1/1982	1/1/2003	7397	1,938,028,868
37002	7,473.76	8/1/1993	1/1/2003	3440	25,709,734
37002	2,178.16	6/1/1991	1/1/2003	4232	9,217,973
37002	4,991.62	6/1/1990	1/1/2003	4597	22,946,477
37002	36,197.32	12/1/1989	1/1/2003	4779	172,986,992
37002	11,888.07	4/1/1989	1/1/2003	5023	59,713,776
37002	7,552.00	3/1/1985	1/1/2003	6515	49,201,280
37002	561,549.69	10/1/1982	1/1/2003	7397	4,153,783,057
37002	2,149.77	7/1/1982	1/1/2003	7489	16,099,628
37002	2,010.81	6/1/1982	1/1/2003	7519	15,119,280
expansion	47,109,740.93	5/31/2002	1/1/2003	215	10,128,594,300
Total	326,541,457.56				1,998,504,477,806
					6120.216688
					16.77

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existing plant, only account 368--compressor station equipment

Account	plant	in service date	current date	age in days	weighted cost
36610	0.00	12/31/2002	1/1/2003	1	0
36610	0.00	7/1/1984	1/1/2003	6758	0
36610	0.00	6/1/1984	1/1/2003	6788	0
36610	0.00	10/1/1982	1/1/2003	7397	0
36620	0.00	5/31/2000	1/1/2003	945	0
36620	0.00	11/1/1993	1/1/2003	3348	0
36620	0.00	9/1/1991	1/1/2003	4140	0
36620	0.00	10/1/1982	1/1/2003	7397	0
36630	0.00	6/1/1984	1/1/2003	6788	0
36700	0.00	11/30/2002	1/1/2003	32	0
36700	0.00	10/31/2002	1/1/2003	62	0
36700	0.00	6/30/2000	1/1/2003	915	0
36700	0.00	5/31/2000	1/1/2003	945	0
36700	0.00	3/31/2000	1/1/2003	1006	0
36700	0.00	2/1/1997	1/1/2003	2160	0
36700	0.00	9/1/1996	1/1/2003	2313	0
36700	0.00	11/1/1995	1/1/2003	2618	0
36700	0.00	5/1/1995	1/1/2003	2802	0
36700	0.00	2/1/1990	1/1/2003	4717	0
36700	0.00	2/1/1985	1/1/2003	6543	0
36700	0.00	12/1/1983	1/1/2003	6971	0
36700	0.00	12/1/1982	1/1/2003	7336	0
36700	0.00	10/1/1982	1/1/2003	7397	0
36711	0.00	11/1/1993	1/1/2003	3348	0
36800	0.48	9/30/2002	1/1/2003	93	45
36800	10,680,915.74	7/1/1997	1/1/2003	2010	21,468,640,637
36800	259,729.57	6/1/1997	1/1/2003	2040	529,848,323
36800	8,365.39	8/1/1996	1/1/2003	2344	19,608,474
36800	(195,038.67)	11/1/1995	1/1/2003	2618	(510,611,238)
36800	50,604.17	9/1/1994	1/1/2003	3044	154,039,093
36800	12,775.50	4/1/1987	1/1/2003	5754	73,510,227
36800	30,552.53	12/1/1983	1/1/2003	6971	212,981,687
36800	3,677.19	10/1/1983	1/1/2003	7032	25,858,000
36800	294,740.56	10/1/1982	1/1/2003	7397	2,180,195,922
36901	0.00	11/30/2002	1/1/2003	32	0
36901	0.00	10/31/2002	1/1/2003	62	0
36901	0.00	2/1/1995	1/1/2003	2891	0
36901	0.00	11/1/1993	1/1/2003	3348	0
36901	0.00	9/1/1991	1/1/2003	4140	0
36901	0.00	8/1/1985	1/1/2003	6362	0
36901	0.00	10/1/1982	1/1/2003	7397	0
37001	0.00	2/1/1985	1/1/2003	6543	0
37001	0.00	12/1/1984	1/1/2003	6605	0
37001	0.00	10/1/1982	1/1/2003	7397	0
37002	0.00	8/1/1993	1/1/2003	3440	0
37002	0.00	6/1/1991	1/1/2003	4232	0
37002	0.00	6/1/1990	1/1/2003	4597	0
37002	0.00	12/1/1989	1/1/2003	4779	0
37002	0.00	4/1/1989	1/1/2003	5023	0
37002	0.00	3/1/1985	1/1/2003	6515	0
37002	0.00	10/1/1982	1/1/2003	7397	0
37002	0.00	7/1/1982	1/1/2003	7489	0
37002	0.00	6/1/1982	1/1/2003	7519	0
Total	11,146,322.46				24,154,071,170
					2166.999139
					5.94

Trailblazer
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existing plant, without acct 368--compressor station equipment

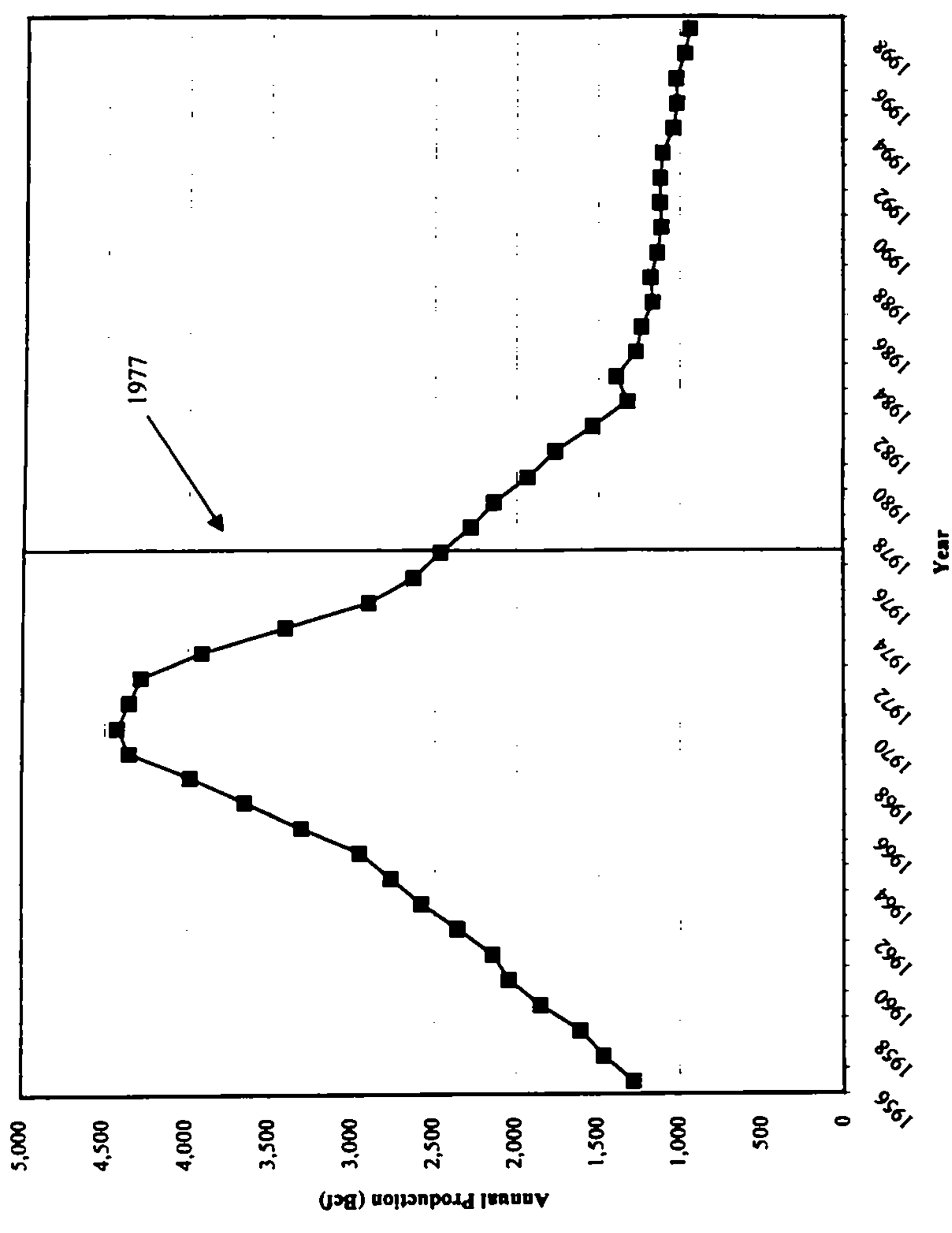
Account	plant	in service date	current date	age in days	weighted cost
36610	30,107.46	12/31/2002	1/1/2003	1	30,107
36610	21,305.41	7/1/1984	1/1/2003	6758	143,981,961
36610	33,133.34	6/1/1984	1/1/2003	6788	224,909,112
36610	1,338,657.81	10/1/1982	1/1/2003	7397	9,902,051,821
36620	76,225.75	5/31/2000	1/1/2003	945	72,033,334
36620	7,338.57	11/1/1993	1/1/2003	3348	24,569,532
36620	4,735.23	9/1/1991	1/1/2003	4140	19,603,852
36620	295,277.17	10/1/1982	1/1/2003	7397	2,184,165,226
36630	24,721.44	6/1/1984	1/1/2003	6788	167,809,135
36700	9,415.05	11/30/2002	1/1/2003	32	301,282
36700	167,935.13	10/31/2002	1/1/2003	62	10,411,978
36700	38.39	6/30/2000	1/1/2003	915	35,127
36700	6,900.62	5/31/2000	1/1/2003	945	6,521,086
36700	2,522.09	3/31/2000	1/1/2003	1006	2,537,223
36700	2,535,000.00	2/1/1997	1/1/2003	2160	5,475,600,000
36700	512,540.23	9/1/1996	1/1/2003	2313	1,185,505,552
36700	227,443.21	11/1/1995	1/1/2003	2618	595,446,324
36700	62,298.00	5/1/1995	1/1/2003	2802	174,558,996
36700	36,274.02	2/1/1990	1/1/2003	4717	171,104,552
36700	216.76	2/1/1985	1/1/2003	6543	1,418,261
36700	7,183.13	12/1/1983	1/1/2003	6971	50,073,599
36700	(3,489.56)	12/1/1982	1/1/2003	7336	(25,599,412)
36700	258,336,948.57	10/1/1982	1/1/2003	7397	1,910,918,408,572
36711	1,811.51	11/1/1993	1/1/2003	3348	6,064,935
36800	0.00	9/30/2002	1/1/2003	93	0
36800	0.00	7/1/1997	1/1/2003	2010	0
36800	0.00	6/1/1997	1/1/2003	2040	0
36800	0.00	8/1/1996	1/1/2003	2344	0
36800	0.00	11/1/1995	1/1/2003	2618	0
36800	0.00	9/1/1994	1/1/2003	3044	0
36800	0.00	4/1/1987	1/1/2003	5754	0
36800	0.00	12/1/1983	1/1/2003	6971	0
36800	0.00	10/1/1983	1/1/2003	7032	0
36800	0.00	10/1/1982	1/1/2003	7397	0
36901	9,654.47	11/30/2002	1/1/2003	32	308,943
36901	39,237.20	10/31/2002	1/1/2003	62	2,432,706
36901	14,505.51	2/1/1995	1/1/2003	2891	41,935,429
36901	15,116.97	11/1/1993	1/1/2003	3348	50,611,616
36901	12,374.53	9/1/1991	1/1/2003	4140	51,230,554
36901	5,575.27	8/1/1985	1/1/2003	6362	35,469,868
36901	3,505,973.57	10/1/1982	1/1/2003	7397	25,933,686,497
37001	20,382.98	2/1/1985	1/1/2003	6543	133,365,838
37001	30,041.13	12/1/1984	1/1/2003	6605	198,421,664
37001	262,002.01	10/1/1982	1/1/2003	7397	1,938,028,868
37002	7,473.76	8/1/1993	1/1/2003	3440	25,709,734
37002	2,178.16	6/1/1991	1/1/2003	4232	9,217,973
37002	4,991.62	6/1/1990	1/1/2003	4597	22,946,477
37002	36,197.32	12/1/1989	1/1/2003	4779	172,986,992
37002	11,888.07	4/1/1989	1/1/2003	5023	59,713,776
37002	7,552.00	3/1/1985	1/1/2003	6515	49,201,280
37002	561,549.69	10/1/1982	1/1/2003	7397	4,153,783,057
37002	2,149.77	7/1/1982	1/1/2003	7489	16,099,628
37002	2,010.81	6/1/1982	1/1/2003	7519	15,119,280
Total	268,285,394.17				1,964,221,812,336
					7321.389293
					20.06

Historical Gas Production for South Louisiana Onshore
(Volume in Bcf)

Year	Annual Production
1956	1,282
1957	1,466
1958	1,606
1959	1,852
1960	2,046
1961	2,146
1962	2,359
1963	2,579
1964	2,765
1965	2,956
1966	3,308
1967	3,654
1968	3,983
1969	4,352
1970	4,426
1971	4,354
1972	4,284
1973	3,914
1974	3,411
1975	2,905
1976	2,632
1977	2,468
1978	2,279
1979	2,139
1980	1,932
1981	1,764
1982	1,536
1983	1,322
1984	1,391
1985	1,270
1986	1,236
1987	1,167
1988	1,179
1989	1,140
1990	1,113
1991	1,122
1992	1,120
1993	1,105
1994	1,038
1995	1,017
1996	1,022
1997	968
1998	938

Source: Technology Assessment Division of the Louisiana Department of Natural Resources.

Extrapolation of South Louisiana Gas Production



AVERAGE SERVICE LIFE IS 65.00SURVIVOR CURVE IS [illegible] TRUNCATION TO 34.00YEARS
AFTER OBSERVATION YEAR.

OS.YEAR	AVE.SL	R.LIFE	R.L./ASL	CUR % SURV		% SURV TRUNC
1.00	32.9	32.4	.9855	99.93		87.86
2.00	33.8	32.4	.9578	99.78		87.19
3.00	34.7	32.3	.9316	99.62		86.50
4.00	35.5	32.2	.9067	99.45		85.78
5.00	36.4	32.1	.8831	99.27		85.03
6.00	37.2	32.0	.8607	99.09		84.26
7.00	38.1	31.9	.8394	98.89		83.45
8.00	38.9	31.8	.8190	98.69		82.62
9.00	39.7	31.7	.7996	98.47		81.77
10.00	40.5	31.6	.7811	98.25		80.88
11.00	41.3	31.5	.7634	98.01		79.96
12.00	42.1	31.4	.7464	97.77		79.01
13.00	42.9	31.3	.7301	97.51		78.03
14.00	43.7	31.2	.7145	97.24		77.02
15.00	44.4	31.1	.6994	96.95		75.97
16.00	45.2	31.0	.6850	96.66		74.89
17.00	45.9	30.8	.6711	96.35		73.78
18.00	46.7	30.7	.6576	96.02		72.64
19.00	47.4	30.6	.6447	95.68		71.46
20.00	48.1	30.4	.6322	95.33	.37	70.25
21.00	48.8	30.3	.6201	94.96	.39	69.01
22.00	49.5	30.1	.6084	94.57	.40	67.73
23.00	50.2	29.9	.5970	94.17		66.42
24.00	50.8	29.8	.5860	93.75		65.07
25.00	51.5	29.6	.5753	93.32		63.70
26.00	52.1	29.4	.5649	92.86		62.29
27.00	52.7	29.2	.5548	92.39		60.85
28.00	53.3	29.0	.5449	91.90		59.38
29.00	53.9	28.8	.5353	91.39		57.89
30.00	54.5	28.6	.5259	90.85		56.36
31.00	55.0	28.4	.5167	90.30		54.81
32.00	55.6	28.2	.5078	89.72		53.23
33.00	56.1	28.0	.4990	89.13		51.64
34.00	56.6	27.8	.4904	88.50		50.02
35.00	57.1	27.5	.4820	87.86		48.38
36.00	57.6	27.3	.4737	87.19		46.73
37.00	58.0	27.0	.4656	86.50		45.07
38.00	58.5	26.7	.4576	85.78		43.40
39.00	58.9	26.5	.4497	85.03		41.72
40.00	59.3	26.2	.4419	84.26		40.03
41.00	59.7	25.9	.4343	83.45		38.35
42.00	60.1	25.6	.4267	82.62		36.67
43.00	60.4	25.3	.4193	81.77		35.00
44.00	60.8	25.0	.4119	80.88		33.34
45.00	61.1	24.7	.4046	79.96		31.69
46.00	61.4	24.4	.3974	79.01		30.06
47.00	61.7	24.1	.3902	78.03		28.46
48.00	62.0	23.7	.3831	77.02		26.88
49.00	62.2	23.4	.3761	75.97		25.32

AVERAGE SERVICE LIFE IS 30.00SURVIVOR CURVE IS R3 TRUNCATION IS 34.00YEARS AFTER OBSERVATION YEAR.

OS.YEAR	AVE.SL	R.LIFE	R.L./ASL	CUR % SURV	% SURV TRUNC
1.00	28.6	28.1	.9828	99.97	31.98
2.00	28.9	27.5	.9491	99.91	27.11
3.00	29.2	26.7	.9160	99.82	22.54
4.00	29.4	26.0	.8836	99.71	18.35
5.00	29.6	25.2	.8516	99.57	14.62
6.00	29.7	24.3	.8201	99.40	11.37
7.00	29.8	23.5	.7888	99.18	8.60
8.00	29.9	22.6	.7580	98.92	6.32
9.00	29.9	21.8	.7274	98.60	4.47
10.00	29.9	20.9	.6972	98.21	3.01
11.00	30.0	20.0	.6673	97.75	1.91
12.00	30.0	19.1	.6378	97.20	1.11
13.00	30.0	18.3	.6087	96.56	.56
14.00	30.0	17.4	.5800	95.81	.24

1

Iowa Curves Used

Account	Frontier	Collins	Allegheny	Atlantic Seaboard	Tomahawk (1982)	National Transit (Gathering) (Storage)	Ohio (Gathering) (Transm.)	Ohio (Product)	[illegible]	Solio (Gathering) (Gas Supply)	Solio Trunk (C+P)	Tomahawk 1988
152	60 S1	60 S1	65 R2	65 R2	60 S1	32 R2	12 R4	60 S1	60 S1	30 R2	40 S1	60 S1
153	65 R2	65 R2	65 R2	65 R2	65 R2	29 R1	32 R4	65 R2	65 R2	30 R2	65 R2	65 R2
154	35 R2	35 R2	25 R1	50 R2	50 R2	26 R1	25 R1	35 R2	35 R2	22 R2	35 R2	50 R2
155	65 R2	65 R2	65 R2	65 R2	65 R2	29 R1	29 R2	65 R2	65 R2	29 R3	65 R2	65 R2
156	50 S2	50 S2	50 S2	50 S2	50 S2	19 R1		50 S2	50 S2	23 S2	40 S2	50 S2
157				25 S2								
158	30 S1	30 S1	20 S1	25 S2	10 S1	20 S1	20 SC	30 S1	30 S1	20 S1	40 S1	30 S1
159				25 S2	20 S2	20 S2				20 S1	25 S1	20 S2
160	35 R1	35 R1	25 R1	25 S2	35 R1	14 R1	22 R1	35 R1	35 R1	30 R2	30 R1	
161	40 S2		40 S2	40 S2		35 S1	30 S1	40 S2	40 S2	30 S1	40 S2	40 S2
162			23 S1	30 S1			18 SC	23 S1		20 S1	23 S1	
163	10 S1		20 S1	20 S1		26 S1		20 S1	20 S1	10 S1	10 S1	
164		20 S1	20 S1	20 S1		15 S1		20 S1	20 S1	26 S1	28 S1	
165	10 S1	15 S1	20 S1	15 S1		9 S1	15 S1		15 S1	[illegible]	[illegible]	
166			15 S1			15 S1	15 S1	15 S1	15 S1			

2

Some Curves Used

Account	El Paso Ala.		El Paso N/C		El Paso Rebuilt		Dorchester		Cities Service		Choice					Picked Gathering		Picked Trunk	
152 ROW	60	S1	60	S1	60	S1	60	S1	60	S1						30	R2	60	S1
153 Line Pipe	65	R2	65	R2	65	R2	65	R2	65	R2						30	R2	55	R2
154 Line pipe fittings	35	R2	35	R2	50	R2	50	R2	35	R2	35	R2(8)	50	R2(5)	[illegible]	25	R1	50	R2
155 M/S Equip	65	R2	65	R2	65	R2	65	R2	65	R2						30	R2	60	R2
156 Bldgs	50	S2	50	S2	50	S2			50	S2						25	S2	50	S2
157 Trucks																		25	S2
158 Comp Equip	30	S1	30	S1	30	S1			30	S1						20	S1	30	S1
159 Mobile Tools and machinery	20	S2									20	S2(4)	25	S2(2)	[illegible]	20	S1	20	S2
160 D.T. Equip	35	R1	35	R1	35	R1			35	R1						35	R1	35	R1
161 Oil Tanks																20	S1	20	S2
162 Delivery facilities									25	S1	25	S1(4)	30	S1(2)	[illegible]	20	S1	30	S1
163 Communication Systems			20	S1							20	S1(5)	10	S1(3)	[illegible]	20	S1	20	S0
164 Off. Furn			20	S1					20	S1						20	S1	20	S1
165 Vehicles									15	S1						[illegible]	[illegible]	[illegible]	[illegible]
166 Other equip																15	S1	15	S1

[illegible] 1-4-89

Account	11 Picked Gathering		12 Picked Trans		
152 Row	30	R2	60	S1	65R2
153 Line Pipe	30	R2	65	R2	
154 Line pipe	25	R1	50	R2	
155 O/L Constr	30	R2	65	R2	
156 Bldgs	25	S2	50	S2	
157 Boilers	-		25	S2	
158 Pump Equip	20	S1	30	S1	
159 Machine Tool	20	S1	20	S2	
160 O.S. Equip	25	R1	35	R1	
161 oil Tanks	30	S1	40	S2	
162 Delivery E.	20	S1	30	S1	
163 Communicat	20	S1 ?	20	S1	10
164 off Furn	20	S1	20	S1	4
165 Vehicles	7 15	S1 S1	7 15	S1 S1	
166 Other prop	15	S1	15	S1	

need to revise
3-31-89

prior 1/89
R.O.W.
Used 60 S1 for acct 152 and 65 R2 for acct 153 (L.P) to illustrate that line pipe will often physically last longer than most fields or reservoirs and hence the R.O.W. also

use 65 R2
10/89

← use $\frac{1}{ASL}$? (i.e. $\frac{1}{10}$)

← use $\frac{1}{ASL}$ (i.e. $\frac{1}{4}$, 25% each) for example (see next pages)

Northwest Pipeline Corporation
Docket No. RP95-409-000
FERC Staff Data Request - KJP
October 20, 1995

Request KJP-14

Provide support and all workpapers for the proposed lives of each General Plant account.

Response:

Refer to the workpapers below for General Plant depreciation lives.

The workpapers have been subdivided into four parts as follows:

Part 1 - Includes memos and attachments relating to computers, communication equipment, communication structures and SCADA. Among other things, the documentation shows that Northwest's 386 and 486 computer equipment was held (on a weighted average basis) a total of 3.1 years.

Part 2A - Reflects the average length of service for retirements (on a weighted average basis) for assets proposed to be reclassified from transmission to general plant. In summary, the average length of service for these assets is as follows:

Communication Equipment -	6.97 years
Communication Structures -	17.68 years
Land Rights -	11.02 years
Computers -	5.74 years
Office Furniture and Equipment -	12.30 years
Tools and Equipment -	9.44 years
SCADA -	4.83 years

Part 2B - Reflects the average length of service for retirements (on a weighted average basis) for all other general plant not reflected in Part 2A. In summary, the average length of service for these assets is as follows:

Computers	3.72 years
Transportation Equipment - Vehicles -	3.12 years
Communication Equipment -	10.28 years
SCADA -	7.90 years
Tools and Equipment -	10.99 years

Part 3 - Reflects average age calculations for general plant at 12/31/94. The following summarizes the results.

4

2

Portland, RP02-13

		v	√	my rst	NW RP95	cams
391	office	10	15	10 √ 15	12.3	
392	transpr	5	5	5 √	3.12	7.4
393	stores	5	5	5 √		15
394	tools	10	10	10 √	9.44	
397	comm.	10	10	10 √	6.97	
398	misc	15	20	20 15 √		
399	other tangible	3	5	3		

Trailblazer Pipeline Company
Docket No. RP03-162-000
from Exhibit No. TPC-56, Schedule No. F, page 1 of 2 pages

	(1)	(2)	(3)	(4)
Row	Year	Rem. Life	Future Delivery	Weighted Delivery
(1)	2003	0.5	600	300
(2)	2004	1.5	604	906
(3)	2005	2.5	600	1,500
(4)	2006	3.5	586	2,051
(5)	2007	4.5	563	2,534
Total			2,953	7,291
Avg. Rem. Life, (4)/(3)				2.47