UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Gas Transmission Northwest Corporation) Docket No. RP06- -000

Prepared Direct Testimony of Edward H. Feinstein

Q: Please state your name, occupation and business address.

A: My name is Edward H. Feinstein and my business address is 1155 15th Street, N.W., Suite 400, Washington, D.C. 20005. I am a consulting petroleum engineer with the firm of Brown, Williams, Moorhead & Quinn, Inc.

Q: Please describe your business experience and educational background.

A: I received my Bachelor of Petroleum Engineering degree at the University of Tulsa in May 1963. From July 1963 to February 1998, I worked at the Federal Energy Regulatory Commission ("FERC") and its predecessor, the Federal Power Commission ("FPC"). From the time of my employment at the FPC until approximately 1970, I was engaged in work involving economic feasibility studies in certificate proceedings under the Natural Gas Act ("NGA"). This work was concerned primarily with market, engineering, and financial analyses for the purpose of determining the economic feasibility of pipeline projects proposed in certificate applications. From 1970 to the present, my efforts have been concentrated on determining the appropriate depreciation rates for oil and gas pipeline facilities, including the determination of potential supplies of oil and natural gas, and with other rate issues such as storage utilization, operations and cost allocation and gathering rates. During my nearly 35 years with the

Commission, I earned positions of increasing responsibility, including Chief of the Depreciation Branch. In March 1998, I joined the firm of Brown, Williams, Scarbrough and Quinn, Inc., predecessor to Brown, Williams, Moorhead & Quinn, Inc. I am a member of the Society of Depreciation Professionals and the Society of Petroleum Engineers. I have presented testimony on many different subjects, including gas supply and deliverability, depreciation, gathering issues, and storage operations and cost allocation.

Q: What is the purpose of your testimony?

A: My testimony addresses the determination of the just and reasonable depreciation rates to be applied to Gas Transmission Northwest Corporation's ("GTN's") depreciable transmission and general plant, as well as an appropriate allowance for negative salvage. As part of the support for my determinations, I am presenting a detailed depreciation study, as well as an assessment of Rocky Mountain gas supplies as they relate to the useful life of GTN's pipeline system.

Q: What are the depreciation rates you have calculated to be applied to GTN's depreciable transmission and general plant?

A: As a result of my studies and determinations, I am recommending the following depreciation rates:

TRANSMISSION PLANT

Depreciation	2.76 percent
Negative Salvage	0.74 percent

GENERAL PLANT

Acct. 391 Office Furniture and Equipment

Office Furniture	6.67 percent

	Computer Hardware	33.33 percent
	PCs and Laptops	33.33 percent
	Computer Software	20.00 percent
	Office Equipment	6.67 percent
Acct. 397	Communication Equipment	10.00 percent
Acct. 392	Transportation Equipment	18.00 percent
Acct. 394	Tools, Shop and Garage Equipment	4.00 percent
Acct. 396	Power Operated Equipment	4.00 percent

Overview

Q: Please explain your depreciation analysis with respect to transmission plant.

A: I analyzed GTN's system operations, along with its markets and sources of gas supply. I determined an average remaining life of GTN's transmission plant based on the expected physical lives of its transmission facilities, as well as an economic life of its pipeline based upon projected Western Canada Sedimentary Basin ("WCSB"), potential Alaska North Slope volumes, Mackenzie Delta volumes and Rocky Mountain Area gas supplies. I also considered how competition in the natural gas industry affects the economic life of GTN's facilities. I applied the average remaining life to each of its plant accounts to determine the composite depreciation rate for the transmission plant function. I determined the negative salvage rate by employing the total negative salvage amount provided to me by GTN Witness Dan A. King, a planning engineer, and Director – Assets Reliability for TransCanada Pipe Lines Limited, to the same physical lives and economic life used to determine the transmission plant depreciation rate. I independently reviewed Witness King's negative salvage analysis and I determined that the calculation used by Mr. King reflects conventional/standard industry practice. Mr.

King's analysis is found in Exhibit No. GTN-21. The methodology I employed for determining GTN's just and reasonable depreciation rates and negative salvage rates is fully consistent with Commission precedent.

Q: What is the reason for the difference between GTN's existing transmission plant depreciation rates and the proposed rates?

A: Schedule No. 1 of Exhibit No. GTN-24 shows a comparison of GTN's existing depreciation rates with the proposed rates. The differences in the proposed transmission plant depreciation rates compared to GTN's existing rates is due to the addition of new, relatively undepreciated facilities, along with an evaluation of the gas supply and competition environment as it affects the useful life of GTN's existing pipeline facilities. Further, in recent years, the level of depreciation was inordinately low, irrespective of the level of Canadian gas supplies.

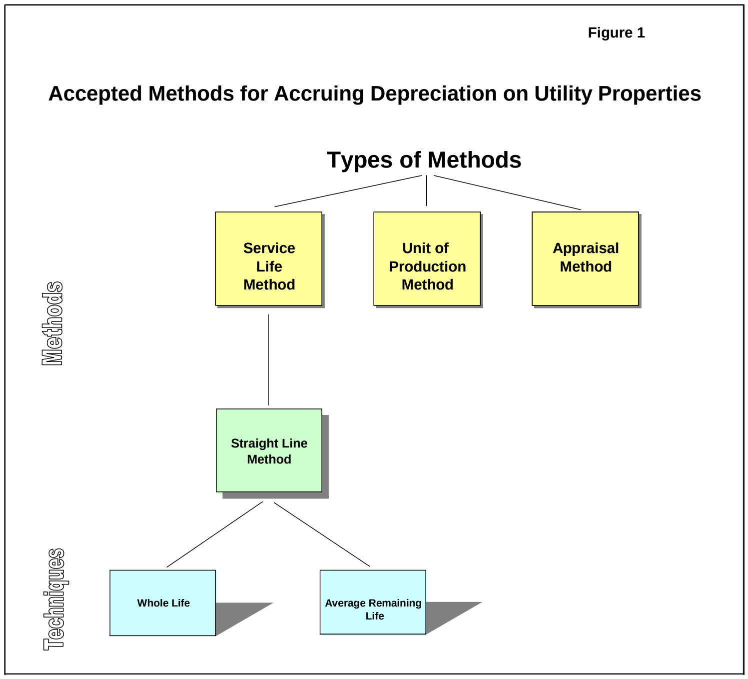
Depreciation Generally

Q: What is depreciation and how it is used for rate purposes?

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

Q: What method or approach did you use to determine GTN's proposed depreciation rates?

A: I used the Average Service Life approach for all classes of property and recommend that GTN's depreciation rates in this case be based on this approach. This approach is the most widely used of all the methods to determine depreciation rates for major onshore transmission pipeline systems. *See* Figure 1 of GTN Exhibit No. 24.



Q: Why did you choose the Average Service Life approach?

A: Depreciation rates depend on estimates of service life of plant investment. Because natural gas pipeline systems are made up of a host of different, complex property units, it would be impractical to calculate and apply separate depreciation rates for each unit of property. This calculation would place an undue burden on the accounting system for depreciation purposes, requiring the maintenance of records for each individual unit of property. Consequently, the normal approach for developing depreciation rates is to calculate the rates for groups of plant based upon average service lives for those groups, which are determined to be appropriate through studies of the forces affecting the lives of the pipeline's facilities. Under this method, individual facilities booked to each relevant FERC account are treated as a single group classified by each account.

Remaining Life Factors

Q: What causes a plant unit to reach the end of its useful life and retirement?

A: The measurement of depreciation recognizes that all plant will ultimately reach the end of its useful life. The end of the useful life and retirement from service may be caused by the following factors:

- wear and tear
- action of the elements
- deterioration
- inadequacy
- obsolescence
- requirements of public authorities
- adequacy of supply or market~~.~~

Q: Can you please describe these factors in more detail and explain which are the most common causes of retirement?

A: The physical causes, such as wear and tear and deterioration, are the most readily observed reasons for retirements. Functional causes, such as inadequacy, obsolescence, requirements of public authorities and inadequacy of supplies or markets, are probably the more prevalent causes of retirements in the pipeline industry.

Q: Please further explain the "adequacy of supply or market" factor and its significance.

A: For a pipeline system such as GTN, all of the above causes of retirement, whether physical or functional, have one thing in common: they are ever-occurring and affect individual facilities. In contrast to factors such as physical deterioration or obsolescence, the adequacy of supply or market is unrelated to the physical characteristics of the property or the action of public authorities. Adequacy of supply or market is probably the single most important factor resulting in premature retirements because this factor may affect a large portion of a pipeline system; therefore, I will treat this subject in more detail. In a depreciation study, the adequacy of supply and markets is referred to as the economic life.

The Depreciation Model

Q: What model did you use for determining depreciation?

A: I employed the straight-line average remaining life method as traditionally adopted by the Commission. It is described as follows:

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

Where,

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

Q: What is the purpose of using the above equation to determine depreciation?

A: The determination of depreciation using the above equation serves three purposes:

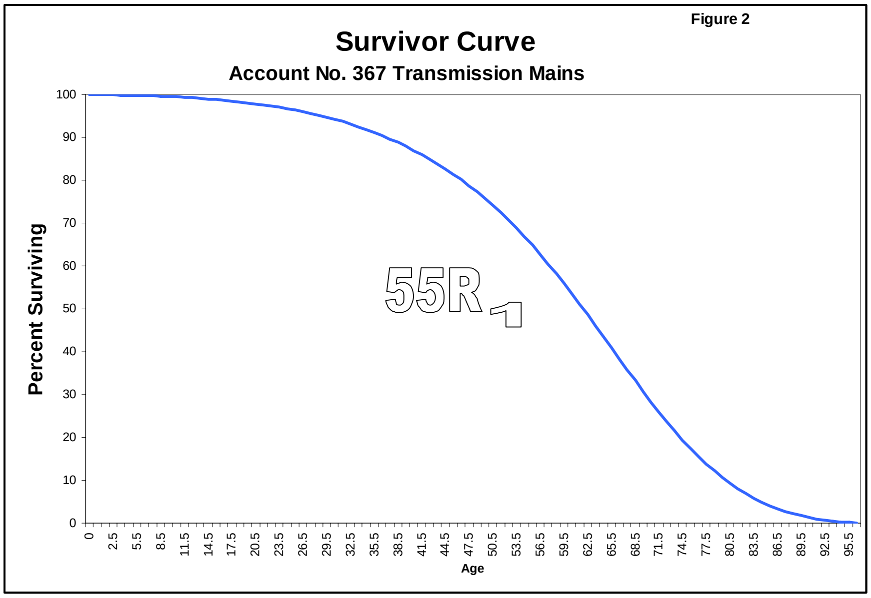
- <u>capital recovery</u> - ratably allocates a known fixed cost,
- <u>cost of removal</u> - ratably allocates a future obligation,
- <u>salvage</u> - ratably reflects recognition of future value.

The concept of an average service life or remaining service life for a property group implies that the various units in the group have different lives. The average life of any group of plant items is a matter of estimate until all the items in that group have been finally retired. The issue here, therefore, is to determine the average life before complete retirement of all units occurs. The average remaining service life method determines the average period of time the facilities will be in service. This is normally done by first determining the historical life of the plant group and then estimating the life expectancy for the items remaining in service. The life experienced plus the expected life comprises the average life for the group. This analysis can be done by determining the separate lives for each of the property units or by constructing a survivor curve for the entire group. In this testimony, I employed the group method and I used a survivor curve for each group of facilities.

Q: What is a survivor curve and what is its purpose?

A: A survivor curve, fitted to a particular type of plant, predicts the average remaining service life and normal retirement pattern of that plant. A survivor curve graphically reflects the percent of capital investment remaining at each age throughout the entire physical life of an original group of property. From the survivor curve, the average service life or average remaining life can be calculated.

The survivor curves are referred to as Iowa type survivor curves (*See* Figure 2, (Schedule No. 3 of Exhibit No. GTN-24)).



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

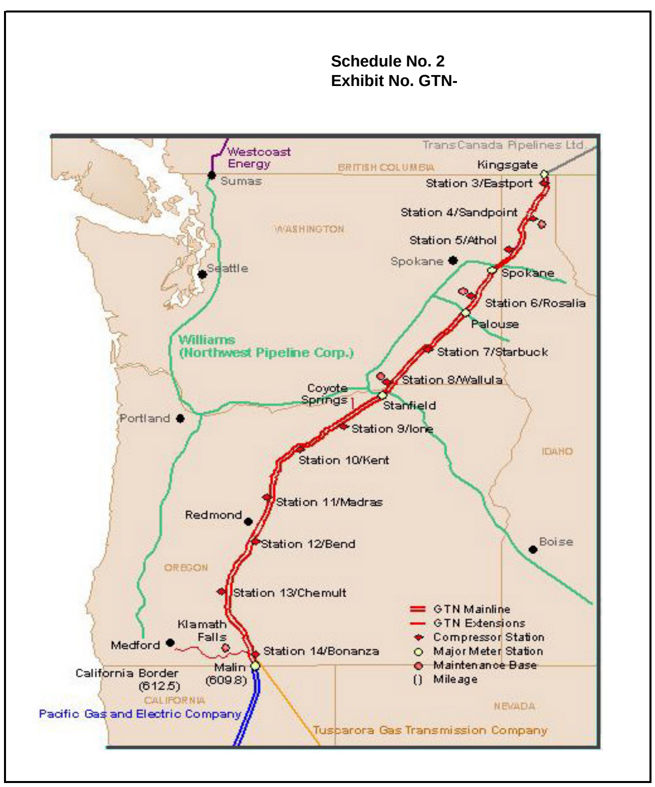
Q: How accurate are survivor curves in determining the physical life of facilities?

A: The determination and use of a survivor curve to determine the physical life of facilities requires a great deal of experience and knowledge in the interpretation of the results of such a study. The use of judgment must include investigation into whether future, normal retirements can be predicted based on the past performance of those facilities. Survivor curves, as they are employed to determine the future interim retirements of plant groups represent a forecast factor and are constructed based upon: a) statistical assembly of historical retirements (where available), b) analysis of the operation of the specific facility group, c) typical lives of similar companies, and d) experience and judgment of this analyst.

<u>Economic Life of the System</u>

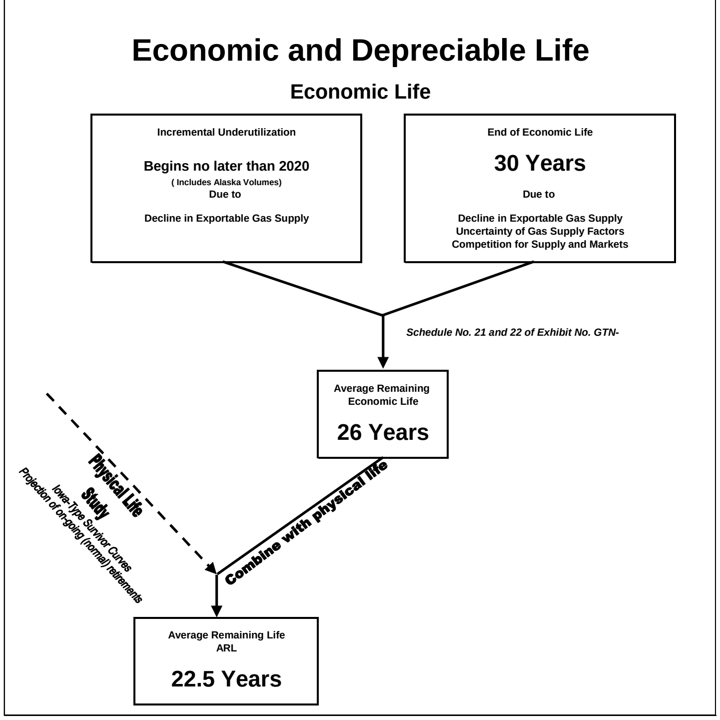
Q: Please describe the economic life of the GTN system.

A: The economic life of the GTN system is dependent primarily upon the productive capability of the supply areas from which it receives gas for transmission. On the other hand, GTN's markets are made up of a combination of municipalities, local distribution companies, an assortment of industrial concerns, cogeneration and other natural gas-fired power generators and various pipeline shippers who seek to transport gas produced in the WCSB and Rocky Mountain region to their end use markets or facilities. Generally, the life of GTN's markets, in and of themselves, is relatively long-term. However, any potential loss of markets may affect the useful life of a particular facility or of some portion thereof. A map of GTN's pipeline system is shown in Schedule No. 2 of Exhibit No. GTN-24.



Adequate supply of gas for shipment is crucial to the remaining life of a pipeline system. Essentially, the current main source of gas for transportation in GTN's pipeline facilities is the gas supplies of the WCSB. To a lesser extent, the U.S. Rocky Mountain Region is also a source of gas for shipment. Specifically, GTN Witness Walter W. Haessel has analyzed and forecasted the amount of gas available from the WCSB and other related sources, such as potential Alaskan and Mackenzie Delta pipeline gas. I analyzed the Rocky Mountain gas supply as it would affect GTN's system. I then assembled such availability forecasts and performed studies concerning the supply life. The results of those studies, when directly related to GTN's existing facilities, indicate an economic end life of 30 years. The average economic life of GTN's facilities, which I will discuss further in my testimony, equates to 26 years. This economic life is used to determine the average remaining life for the calculation of depreciation in this proceeding. A diagram describing the procedure in determining the average remaining economic life is shown in Figure 3 of Exhibit No. GTN-24.

Figure 3



Q: **Could gas from sources other than GTN's traditional gas supply areas flow through the majority of GTN's existing facilities?**

A: GTN's existing facilities are geographically placed such that gas supplies reasonably and economically available to the system come from only certain gas supply regions. GTN's traditional mainline facilities are not geographically situated to carry significant amounts, if any, of, for example, Midcontinent or Gulf Coast gas. Even some Rocky Mountain region supply areas are not practically available to GTN.

<u>Gas Supply</u>

Q: **Would you please describe the gas supply studies?**

A: GTN Witness Haessel, studied, analyzed and modeled gas supplies located in the WCSB~~,~~ and Northern Frontier areas in order to determine their future capability as supply sources. The future capability of these gas supply areas directly affects the useful life of GTN's facilities. He analyzed data available on the existing proven reserves of natural gas in these areas as well as estimates of potential gas resources in these areas. He modeled the availability of gas from these supply sources in the future. Included in his forecast of Western Canadian gas supplies for export are estimated volumes of conventional and unconventional gas. Gas supply reserves and resources are split into two categories, conventional and nonconventional. Conventional resources are located in distinct accumulations. They generally have more favorable performance characteristics and are responsive to traditional exploratory techniques. Nonconventional resources, such as coalbed methane are typically continuous accumulations that are much larger in Arial extent than conventional distinct accumulations. They also have relatively poor production performance.

Further, GTN also transports gas, presently in small quantities, which is sourced from various U.S. Rocky Mountain regions. I have forecasted overall gas volumes, which would be available from the entire Northern Rocky Mountain region. This gas supply study, The Assessment of Natural Gas Supplies in the Northern Rocky Mountain Region, is presented in Exhibit No. GTN-25. This study, along with GTN Witness Haessel's analysis and consideration of the potential for Alaskan gas to be transported on GTN's system, will allow me to evaluate the effect of gas supply forecasts on operation of GTN's pipeline system in order to determine a realistic economic life of the pipeline facilities that are dependent on such supplies.

Q: Please describe your gas supply study of the Northern Rocky Mountain area.

A: I studied, analyzed and modeled the gas supply of the Rocky Mountain area. With respect to the gas supply areas, I analyzed available data on existing, proven reserves of natural gas, as well as the various estimates of potential gas resources. I constructed a model to forecast the future availability of gas from the relevant supply sources. The purpose of my gas supply analysis is to determine a realistic economic life of pipeline facilities that are dependent upon such supplies.

In order to go about determining the supplies of gas that are realistically accessible through GTN, I recognized the gas resources that are categorized as proven reserves and undiscovered resources. Natural gas resources occur in porous and permeable reservoir rock, which at a particular period in time can be technically and economically produced using normal production practices. However, production from area to area differs because the size, location, physical properties and depth of each reservoir varies widely. The analysis and results of my gas supply study are summarized below.

Q: What are the results of your gas supply analysis.

A: The results of the model indicate a certain amount of risk for pipelines that rely disproportionately upon a single area for their long-term future supplies – regardless of how broad the area. The Northern Rocky Mountain area is presently the main source of gas that could be transported through GTN's pipeline system.

GTN interconnects with Northwest Pipeline Corporation (Northwest), which transports gas produced from two major producing areas: the WCSB and the Rocky Mountain area. Although GTN's facilities are not presently located in the gas producing areas of the Rocky Mountain Region, there are significant supply areas in the Rocky Mountain Area that, in the future, GTN logically would attempt to access.

Q: Approximately how much Rocky Mountain gas presently flows through GTN's system?

A: Presently, approximately 8 percent of the gas flowing through GTN's system is sourced from the Rocky Mountain area.

Q: Did you evaluate other potential gas supplies accessible to GTN?

A: Yes. Although there are other viable supply areas of the Rocky Mountain Area in which GTN could possibly source available gas, the farther the producing area is from GTN's pipeline system, the more uncertain is the potential to connect such supplies. Distance from GTN's pipeline, of course, is not the only gas supply risk factor. Other factors such as gas price differential and the California delivery cost of transportation on GTN compared to other pipelines must be considered. Further, the certainty of connecting gas supplies from other producing areas in the future is not assured, as GTN would be confronted with an array of competitive forces already ensconced in the area.

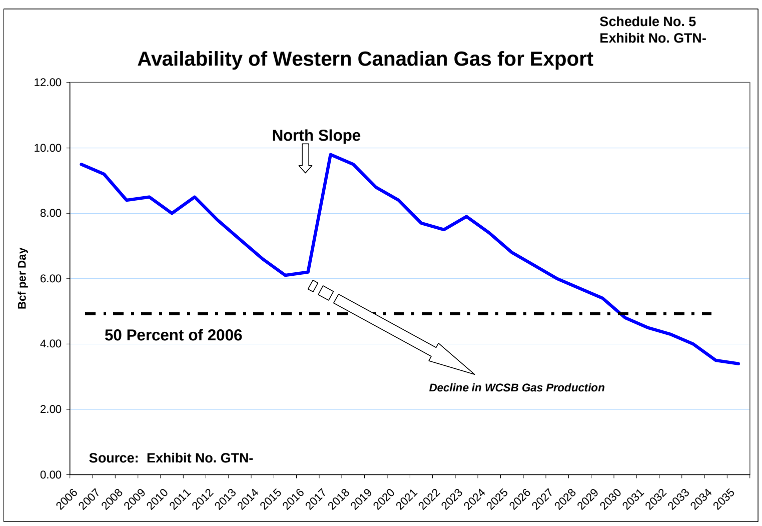
Potential supply areas from which GTN could potentially source its throughput are the large portions of the Green River Basin, Uinta-Piceance Basin and other Rocky Mountain basins located one interconnect charge away. These basins have some potential as promising supply sources, but there is significant uncertainty for them to be viable long-term sources of throughput for GTN.

Q: What is that uncertainty?

A: For one thing, gas supply data for specific areas is highly proprietary making it difficult for pipeline companies to evaluate uncertainties. In addition, there is a significant uncertainty as to which new areas, if any, could source future available gas. It is for the above reasons that I employed the entire states of Utah, Colorado and Wyoming as a surrogate area in which to determine the future supplies of gas that could flow in GTN's system. As described above, by employing the entire Colorado, Utah and Wyoming producing regions in my study, the remaining economic life of GTN's facilities as determined is very conservative. The determination of the amount of productive capacity of gas for which GTN could compete to obtain gas to flow through its system is summarized in Schedule No. 6 page 2 of Exhibit No. GTN-24 and derived in the Assessment of Natural Gas Supplies, Exhibit No. GTN-25. The premise of my gas supply model is to estimate the quantities of gas available from both existing and future sources. The quantity of gas available from existing sources is generally the product of studies produced by the Energy Information Administration ("EIA"). With respect to the availability of gas from future discoveries, I applied a discovery process, finding rate model. The basis of the model is shown on Figure 2 of Exhibit No. GTN-25 and fully explained in the text of the Assessment found in Exhibit No. GTN-25. While the determination of the availability from future discoveries exclusively employed the estimates of potential resources made by the Potential Gas Committee ("PGC"), it actually calculated future resources 5.6 percent greater than those of the PGC (*See* Table 5 of Exhibit No. GTN-25).

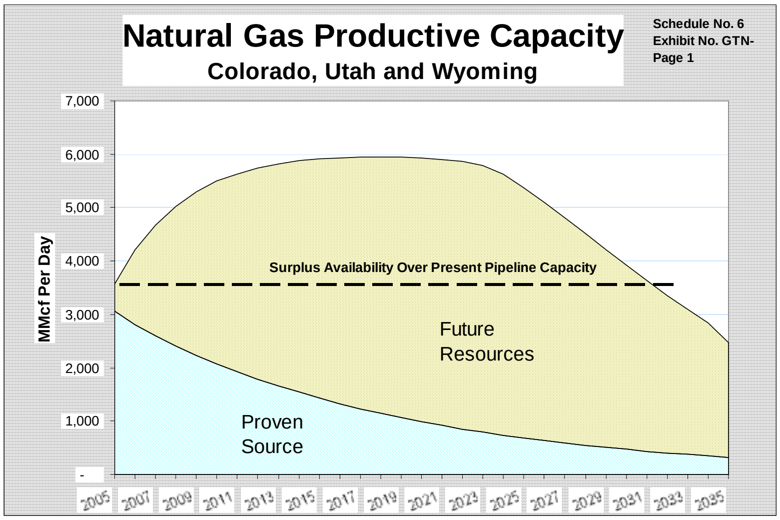
Q: How did you use the results of the gas supply studies?

A: I used the results of GTN Witness Haessel's Western Canada gas supply study as well as my Northern Rocky Mountain area supply study to determine the economic life of GTN's gas transportation system. There are clear trends, as pointed out in this presentation, suggesting that the WCSB gas supply market is moving from a supply/demand balance controlled by demand to one controlled by supply. The production profiles developed herein indicate deficiencies in the ability of the WCSB area to satisfy the need to maintain high levels of throughput compared to the available capacity of pipeline systems. As can be observed from the availability profiles developed by GTN Witness Haessel, supply/demand deficiencies begin to occur in the second decade of the 21st century. The profile of gas available via western Canada is shown in Schedule No. 5 of Exhibit No. GTN-24.



GTN Witness Haessel's WCBS forecasts (including North Slope Alaska and Mackenzie Delta) indicate deficiencies will occur in 2012 and continue to a level of 40 percent by 2030 (25 years from 2005).

Further, by the year 2030, my studies indicate the Rocky Mountain area could provide less than 60 percent of its current productive natural gas capacity. *See* Schedule No.6 of Exhibit No. GTN-24.



Declining gas availability from western Canada can be buoyed somewhat with a shift in gas supply source for GTN's pipeline system to various regions in the Rocky Mountain area. Nevertheless, both areas will exhibit declines in gas supply in the long-term. This creates situations where significant underutilization of present capacity may take place, resulting in potential major retirements of pipeline facilities.

Q: Could you put into context the current status of conventional Canadian gas resources as it affects the economic life of GTN's system?

A: The purpose of depreciation is to allow for the recovery of the investment in facilities. The economic life component is an integral part of that depreciation determination. The determination of the economic life must rely upon logical and reasoned gas supply forecasts as it affects the useful life of GTN's facilities. The gas supply forecasts must meet a standard by which a company can be reasonably assured that it will recoup its investment and shippers can be reasonably assured that the rates they pay reflect their fair generational share of such recovery, no more and no less.

I believe this can be achieved through the gas supply studies of Western Canada that GTN Witness Haessel presented in this proceeding. GTN Witness Haessel constructed a series of scenarios for the exploration, discovery, production and probable export of Western Canadian gas.

Western Canada contains exceedingly large quantities of hydrocarbon resources in-place. In-place gas resources are deposits that reside in the underground reservoirs. Only a fraction of such resources are producible and marketable; however, that fraction ranges from a high of 60 percent of conventional gas resources in Alberta to a very low (less than 10 percent) for unconventional resources such as tight gas and coalbed methane. Figure 4 of Exhibit No. GTN-24 below, shows a diagram of the transition between gas in-place volumes and that which is marketable.

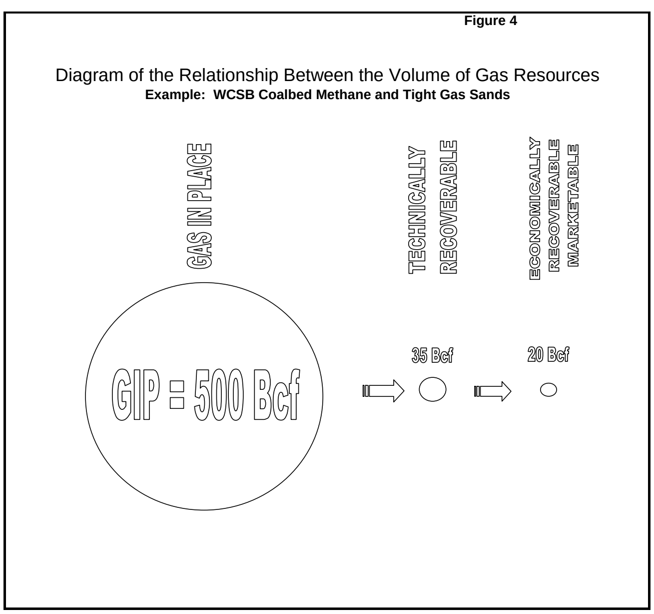


Figure 4

Diagram of the Relationship Between the Volume of Gas Resources
Example: WCSB Coalbed Methane and Tight Gas Sands

Producer exploration for marketable natural gas is driven by a number of factors. The most important factor is the existence of geological prospects. As gas deposits in a basin (such as the WCSB) are discovered, the number and size of remaining deposits to be discovered falls. Higher gas prices and advanced technology such as imaging tools are required to accelerate recovery of available resources and reduce the risk of uneconomic drilling. Nevertheless, future supplies of gas must be limited to the remaining endowment of gas of the WCSB.

The reality of Western Canadian natural gas supplies includes the following facts. The majority of the WCSB conventional resources have been discovered as indicated in Table 1 of Exhibit No. GTN-24 below.

Table 1

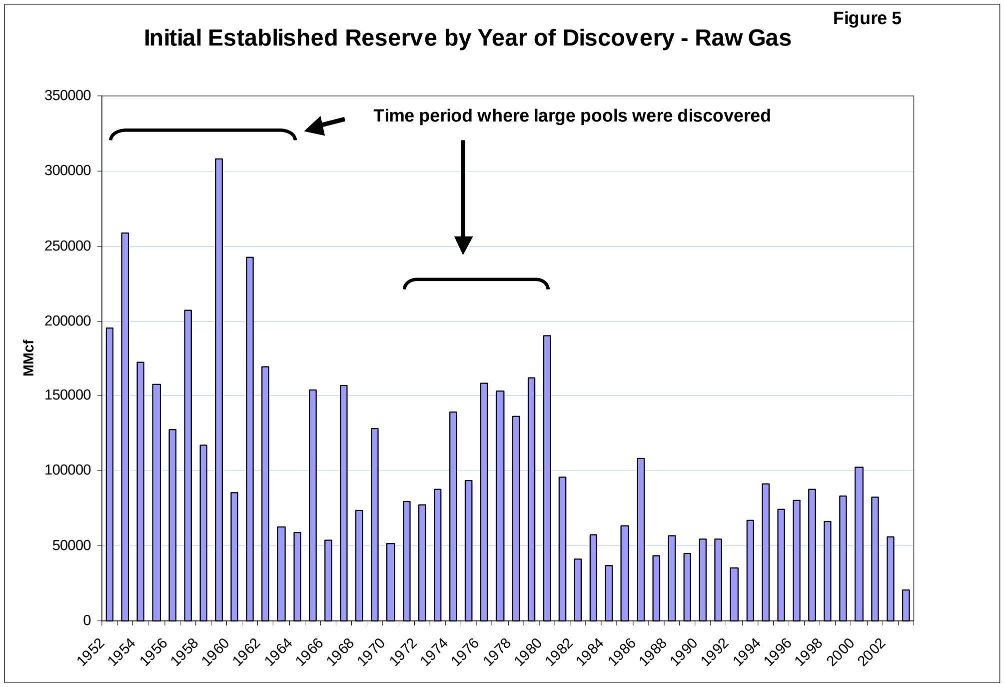
Relationship Between Discovered Resources and Ultimate Potential Gas Resources in the WCSB
Volumes in Bcf
Year-end 2003

	Discovered Marketable Resources	Undiscovered Resource	Ultimate Resource Potential
WCSB Conventional			
Alberta	161,241	61,557	222,798
British Columbia	24,531	26,448	50,978
Saskatchewan	8,591	462	9,053
Southern Territories	1,030	5,929	6,958
Total	195,392	94,395	289,787

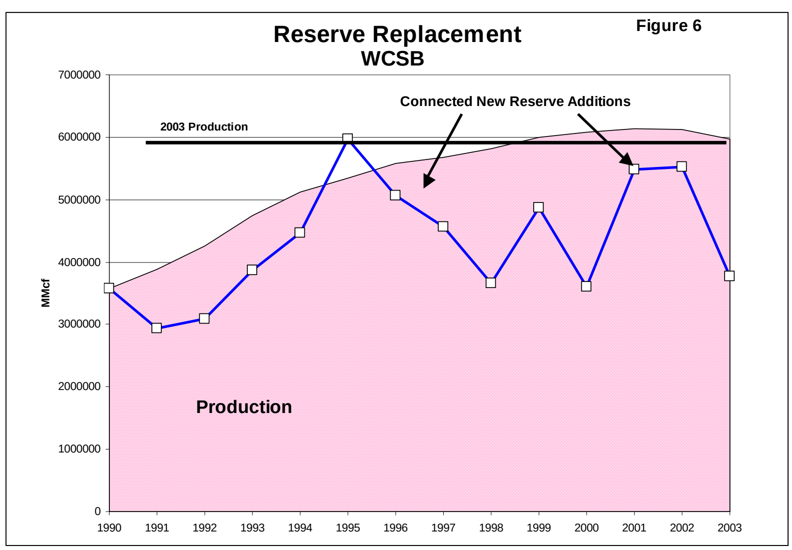
Discovered Marketable Resources includes cumulative production and remaining proved reserves.

Source: AEUB, Alberta's Ultimate Potential for Conventional Natural Gas

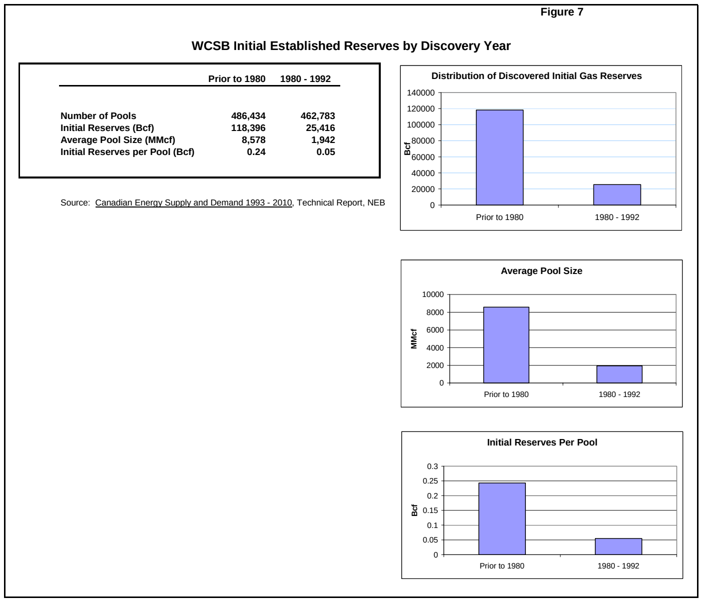
The trend is towards discovery of smaller and smaller pools (gas reservoirs) (*See* Figure 5 of Exhibit No. GTN-24). The largest pools are the most depleted.



Annually connected new reserve additions have not reached a level to replace the 2003 production level since 1995. In six of the eight years the new reserves were from 1 to 2 Tcf (15 to 30 percent) under the consumption level. This is demonstrated in Figure 6 of Exhibit No. GTN-24.

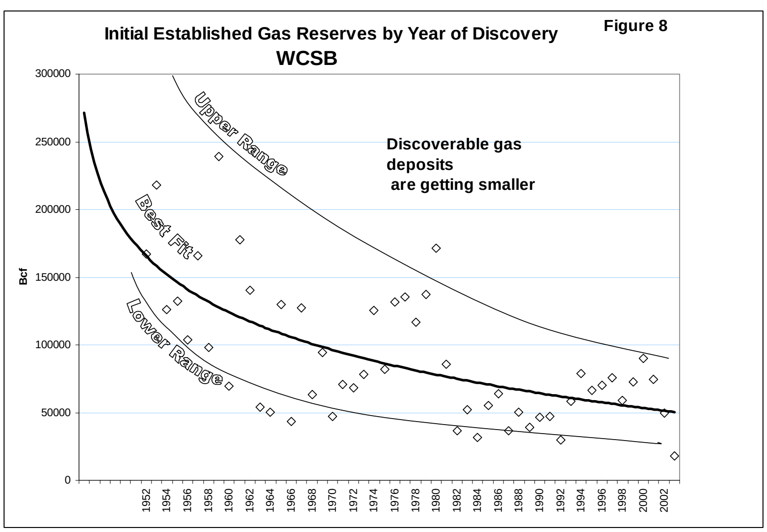


Reserve additions by year of discovery are progressively smaller as shown below in Figure 7 of Exhibit No. GTN-24.

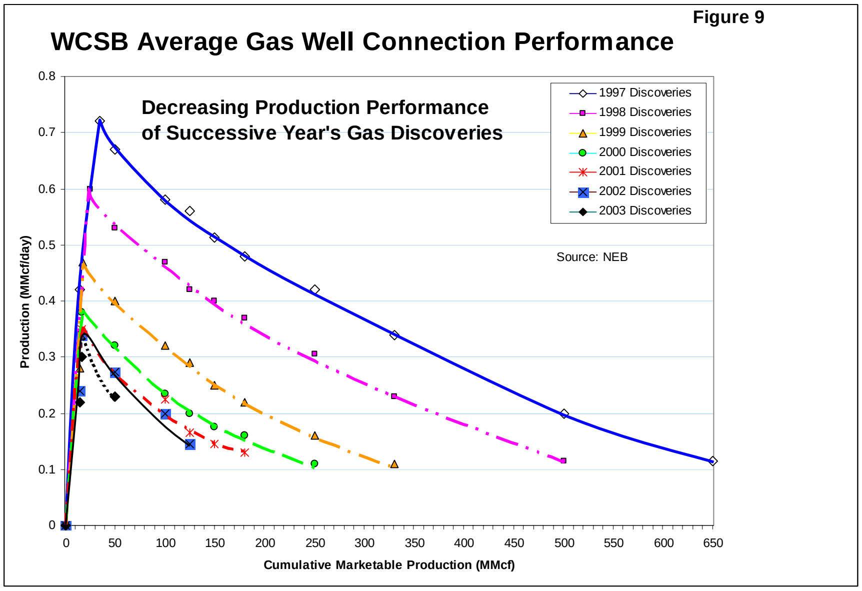


	Prior to 1980	1980 - 1992
Number of Pools	486,434	462,783
Initial Reserves (Bcf)	118,396	25,416
Average Pool Size (MMcf)	8,578	1,942
Initial Reserves per Pool (Bcf)	0.24	0.05

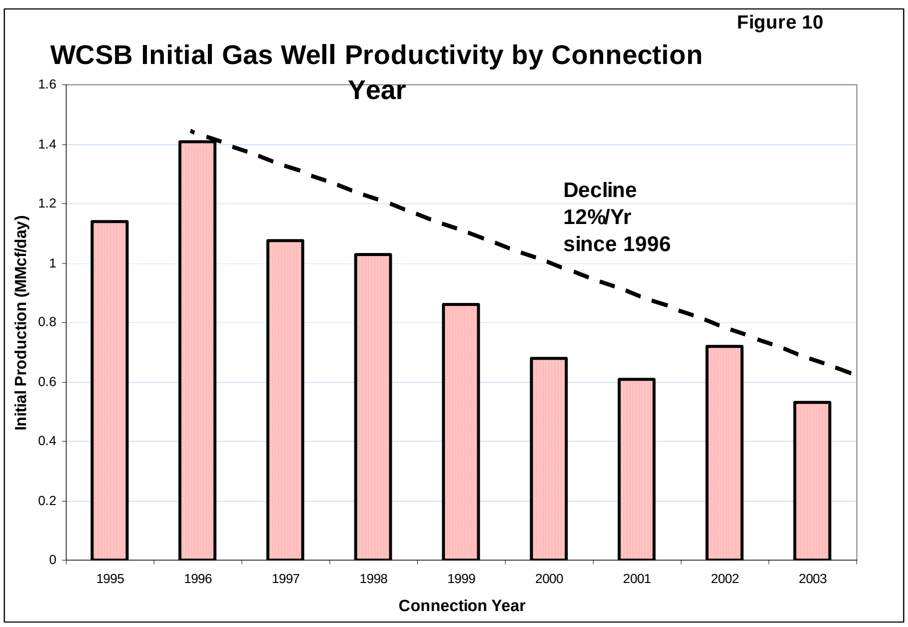
Additional, more recent data is shown by the trend in reserves by discovery year as shown in Figure 8 of Exhibit No. GTN-24.



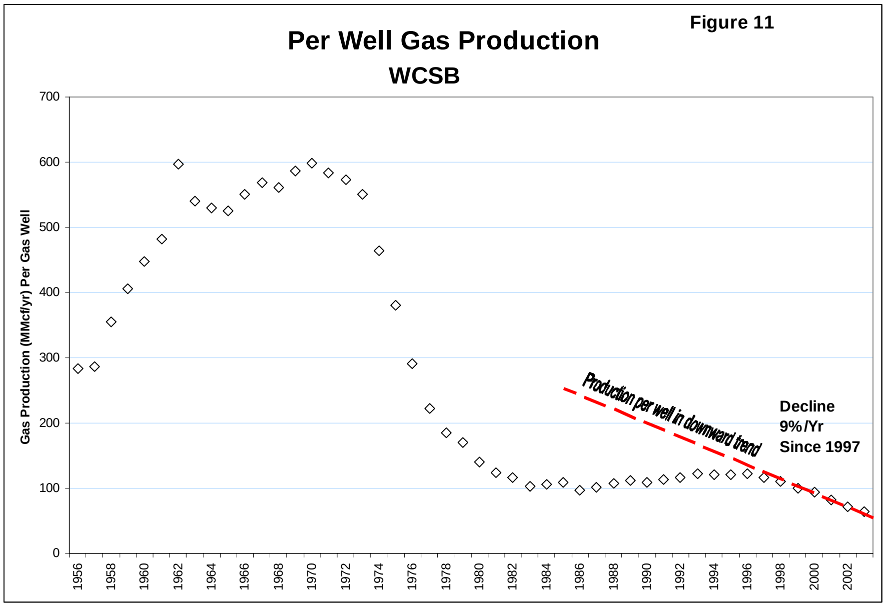
The production performance of successive years' new gas discoveries is decreasing as shown in Figure 9 of Exhibit No. GTN-24.



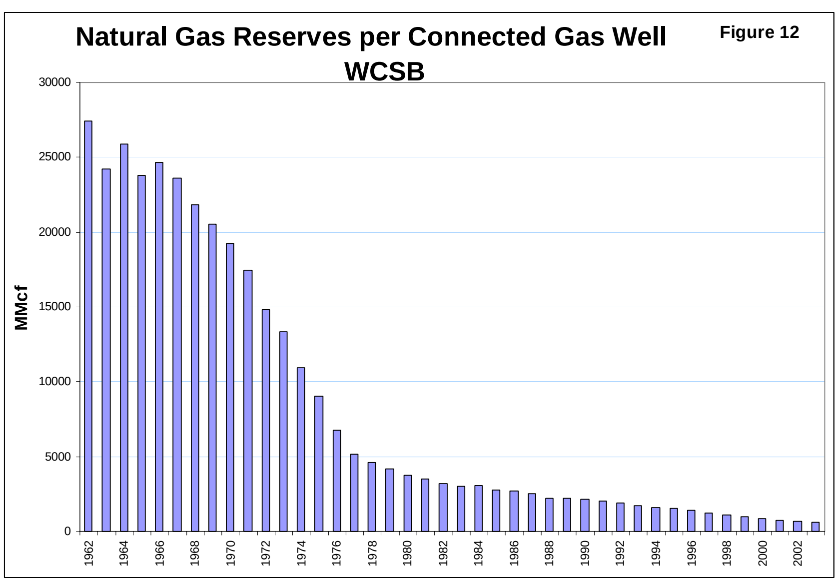
The decline in productivity is shown below in Figure 10 of Exhibit No. GTN-24.



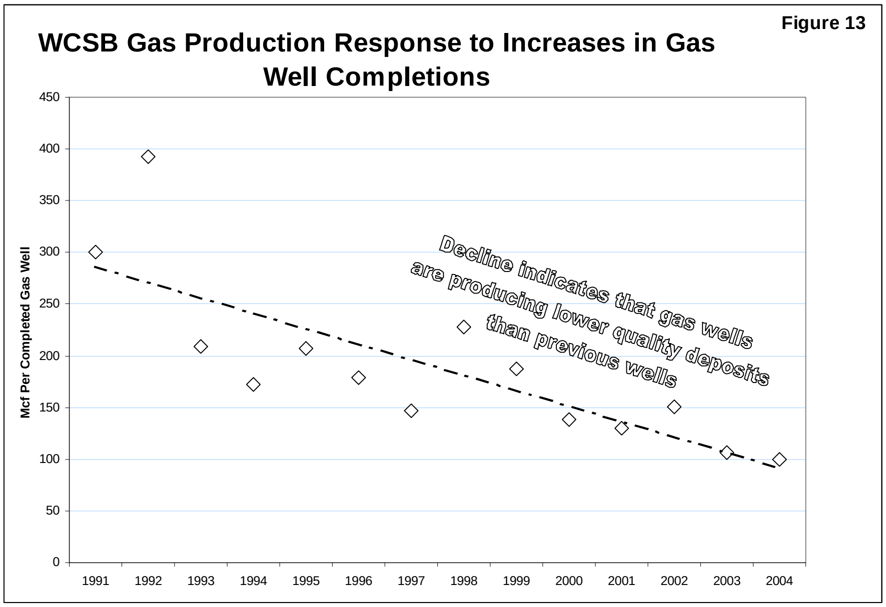
Per well production throughout the WCSB is decreasing as shown in Figure 11 of Exhibit No. GTN-24.



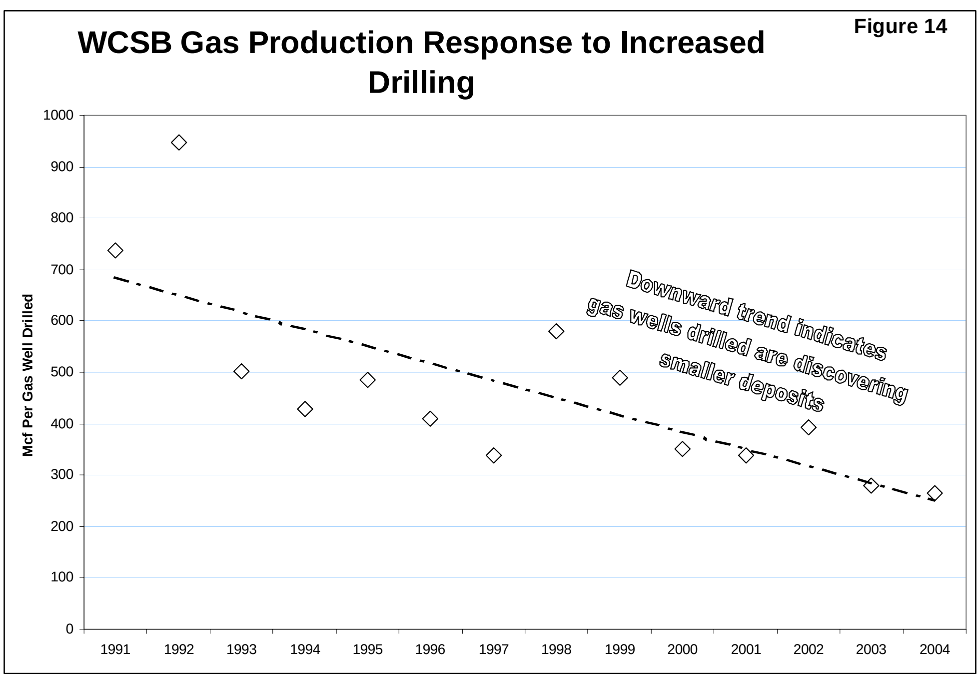
The level of per well reserves throughout the WCSB is decreasing as shown in Figure 12 of Exhibit No. GTN-24.



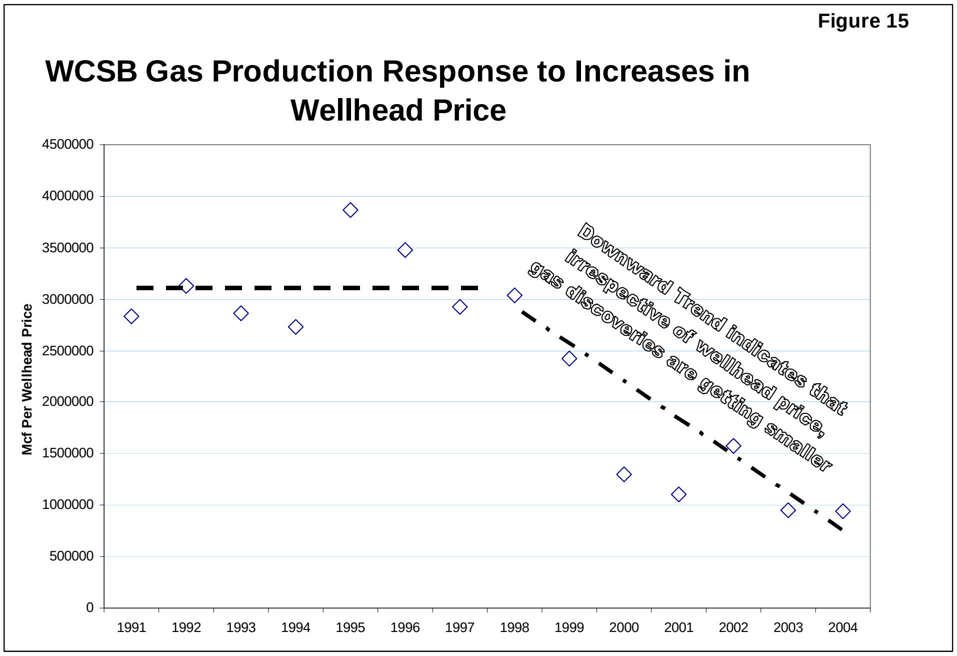
Gas production response to the increasing number of gas wells completed is in a clear decline as shown in Figure 13 of Exhibit No. GTN-24.



Gas production response to increased drilling is a clear decline as shown in Figure 14 of Exhibit No. GTN-24.



Gas production response to wellhead price increases is a clear decline as shown in Figure 15 of Exhibit No. GTN-24.



The above facts indicate that the WCSB is entering the mature stage. The NEB has recognized these facts and states that, "recent drilling and production data suggests that the WCSB may be maturing; and changes in natural gas resource estimates may be warranted for some areas." This is shown in Schedule No. 7 of Exhibit No. GTN-24.

In essence, the WCSB is in a treadmill status where the angle of the treadmill is increasingly steep.

Q: What are the implications of the current status of the conventional WCSB gas supply on the economic life of a pipeline relying on such supplies?

A: The implications are an initially substantial, yet declining, gas supply from conventional gas sources in the WCSB. The decline is discussed by GTN Witness Haessel. The conventional gas resource base of the WCSB is the only gas supply in

Western Canada where there is a long-term reasonably assured supply, based on actual experience, albeit declining.

Q: Mr. Feinstein, are there any other gas supplies that mitigate the declining WCSB conventional gas supplies and underutilization of GTN's system?

A: Yes, there are. They are: the Northern Rocky Mountain area, Canadian coalbed methane and the Mackenzie Delta gas.

Q: Would you please describe how increments of Northern Rocky Mountain gas can mitigate the decline in conventional WCSB gas supplies?

A: Northern Rocky Mountain gas already is supplementing the availability of WCSB gas through GTN's system. Historically, most gas flowing in the GTN system was sourced from the WCSB. And, to a certain extent, Northern Rocky Mountain gas will, in the future, partially supplement the fall-off of WCSB volumes.

The Northern Rocky Mountain area is still growing in the ability to provide gas to the West Coast and Midwest markets. As a result of its growth, more and more capacity to transport such gas to markets will be necessary. What this means is that, in 2020, when the area will begin to decline, GTN's share of such gas will begin to shrink. That is, while the pie is getting smaller (decreasing availability), the added slices (increased available capacity) will reduce the amount to GTN when decline takes place. In the meantime, new take-a-way capacity nevertheless is being proposed for the Rocky Mountain area, and, for the near future, will continue to be added in order to move the presently increasing gas availability to market. However, after the gas availability reaches a peak and begins to decline, underutilization of some pipelines is certain to occur. In other words, there will be excess pipeline capacity at that time. This exacerbates the ability of presently existing Rocky Mountain pipeline capacity to maintain their share of such gas production. Further, I recognized the additional Rocky Mountain gas capacity projects including the potential for major pipeline systems transporting gas east, such as Kinder Morgan's Rockies Express Pipeline LLC REX–West Project. The REX-West Project will be supplied directly or indirectly by the gas supply basins located in the States of Wyoming, Colorado and Utah. This project will provide up to 1,500,000 Dth per day of transportation capacity.

Q: Could you put into context the current status of Western Canada nonconventional gas supplies as those supplies affect the economic life of GTN's pipeline system?

A: As the decline in WCSB production continues, interest in non-conventional resources is expected to increase.

Q: Please describe Canada's unconventional resources.

A: Canada's unconventional resources fall into four categories: coalbed methane ("CBM"), tight gas, shale gas, and gas hydrates.

Q: Please describe CBM and its relationship to Canada's resource base.

A: Large amounts of methane-rich gas are generated and stored in coal formations. Recently, since the late 1980's, stand-alone commercial production of coalbed methane has been undertaken in the United States. Most gas in coal is stored on the internal surfaces of organic matter. Gas content generally increases with certain insitu characteristics, with depth and with reservoir pressure. Fractures, or cleats, that are prevalent in coalbeds are usually filled with water, some of which may be saline. Where water is present, in order for gas to flow to the wellbore, the pressure must be reduced, which is accomplished by removing water from the coalbed.

Large amounts of water, sometimes saline, are produced from most CBM wells. While certain quantities of gas can be technically produced, water disposal options that are environmentally acceptable and yet economically feasible are a concern.

Western Canada (Alberta) contains vast amounts of coal distributed throughout the southern Plains, Foothills and Mountains. However, in contrast to the United States, coalbed formations in Western Canada tend to be thinner, in many cases, buried deeper and have lower permeability (the ability to flow towards the wellbore). There are a number of challenges to successfully developing Canadian CBM. They include: finding localized areas where the CBM has all the right characteristics; developing the correct technique for production; finding viable water disposal options; resolving legal issues over ownership; and overcoming the large cost of compressing produced gas to achieve pipeline pressures.

Less than half of the CBM wells drilled had produced or were producing by year-end 2004. CBM production from such wells in 2004 was minimal (58 MMcf per day, or less than 0.5 percent of just Alberta's gas production.) One thing that must be noted is that there is a difference between CBM production and production from CBM wells. CBM wells are those wells that are drilled to produce CBM, while CBM may produce from conventional gas wells. Conventional gas wells in Alberta, in many instances, produce from a coal zone.

More than 100,000 wells completely penetrate the coal bearing formations, thus, the locations and characteristics of the coal have been well known for some time. The actual CBM production to date continues to remain uncertain because of the current inability to completely differentiate CBM from conventional gas production. Further, recorded reserves and production from conventional sources included CBM to some extent.

As of the end of 2004, the Alberta Energy and Utility Board ("EUB") estimates remaining established reserves of CBM to be 262 Bcf. Schedule No.18 of Exhibit No. GTN-24 shows the various CBM reserves. Industry practice indicates that long-term CBM production will be from project style developments, which would necessarily involve re-completions of existing wells with the drilling of new development wells to reduce costs as much as possible.

Q: Mr. Feinstein, have there been estimates of WCSB CBM resources?

A: Yes, and those estimates vary widely.

Q: Mr. Feinstein, what is the relationship between CBM gas in place and marketable gas that would be produced?

A: Recall that gas in place ("GIP") is only the total amount of gas that resides buried in the reservoir. Only a fraction of such gas can be recovered because of technical and economical constraints. In the case of CBM, according to estimates performed on known data by the EUB in its Supply and Demand outlook, Alberta Reserves 2004, published in 2005, only an average of 6 to 8 percent of the GIP can be recovered once technically recoverable deposits are found and established.

Q: What amount of CBM supply do you believe is reasonable and prudent to employ in a determination of the amount of investment recovery via depreciation accruals.

A: The long-term outlook of volumes of Canadian CBM is far more uncertain than conventional gas supply sources. The reason for such caution is that there is virtually no track record of sustained production from stand-alone Canadian CBM projects.

Q: Would you please describe the other nonconventional gas supply source in Canada -- gas shale?

A: There are over 35,000 producing gas shale wells in the United States, from Texas to Ohio and West Virginia, with a current production of about 600 Bcf per year. Outside the United States, in Canada, the story is quite different, where gas shales have received little attention. There is little, if any indication that gas shales in Canada have similar producible characteristics to those in the United States.

Gas shales are fine grain sedimentary rocks in which a significant component of gas storage is by absorption. They have very low matrix permeability, much less than 1 millidarcy. Permeability is measured in darcies. It is the ability of fluids to flow through porous media (rock-shale). Localized natural fracturing is essential for technical and economic gas reserves. There is no evidence that the Canadian gas shales exhibit any significant amount of localized natural fractures.

Technical and non-technical issues for assessing the resource potential are somewhat similar to that for CBM. These include a lack of production test data, need for natural fractures, water handling issues and need for large continuous land blocks. Only a very small percent of GIP resource would, in any event, be developable. Even within that developable area (natural fractures, *etc*.) only a very low recovery factor would be appropriate.

Q: Would you please describe the other potential nonconventional supply source -- tight gas sands?

A: The WCSB has many potential tight gas zones, especially on the western, deeply buried side of the basin. Gas pool areas with tight gas potential have already produced conventionally; however, the line separating conventional and nonconventional reserves and resources is not sharp. These fields or units have both a conventional and nonconventional component.

Western Canada may not have the same characteristics and potential for tight or what is referred to as "basin centered" gas as seen in the U.S. Rocky Mountain or Gulf Coast regions. Numerous wells have already been drilled through the potential tight gas zones. WCSB basin center (tight gas) developments to date have largely been in "sweet spot" areas (*i.e.*, natural fractures) and little effort has been made to commercialize associated poorer quality, lower grade basin center gas deposits. In the WCSB, deep basin tight gas is generally in small pools with low gas in place. There is very little public data for assessing deep basin centered gas, such as detailed information on well fracture stimulation treatments. Further, Canada does not have a specific definition (for regulatory purposes) of tight gas. Because of the difficulty and potential confusion in terms associated with tight gas resources, efforts to separately quantify tight gas with WCSB runs the risk of double counting resources.

Some of the very low permeability tight gas sands behave differently than conventional reservoirs. One behavior that distinguishes the two is that involving relative permeability, which is not widely known but whose characteristics are widely observed. Wellbore core data show that as the matrix permeability drops from the millidarcy (md) into the tens of microdarcies, range the critical gas saturation in the reservoir (the gas saturation necessary for gas flow) increases and the critical water saturation also increases. This produces a widening range of water saturation at which both phases (gas and water) are effectively immobile. This no-flow regimen is referred to as “permeability jail.” Thus, in sections of reservoir rock that have low permeability and in “permeability jail,” the presence of gas does not translate to recoverable resources. Further, if higher permeability intervals (sweet spot - natural fractures) are the carrier beds for gas production from adjoining lower permeability sections, then as a consequence these intervals will be more prone to water production.

The Canada Gas Potential Committee ("CGPC") assessment does not distinguish between conventional and tight gas. Their estimates include potential tight gas pools, as well as higher permeability pools. Therefore, one can presume that tight gas potential in the WCSB is largely captured in the conventional exploration plays assessed by the CGPC, EUB and National Energy Board ("NEB"). For example, historically 50 percent of WCSB gas wells undergo fracture stimulation (frac job) indicating relatively low permeability. These wells account for 25 percent of new gas production.

Q: Are there other methods you and GTN Witness Haessel could have used to determine the gas resources available, which would have produced better results?

A: While other methodologies could have been used, in my opinion our studies represent the most reasonable method of estimating the size and characteristics of the WCSB and Rocky Mountain region’s gas resource base.

Q: Why did you reject such other potential methodologies?

A: For a study that ultimately determines the recovery of a pipeline’s investment in facilities, it is important that projections of gas production take into consideration only that portion of the ultimate resource that can reasonably be expected to be delivered to markets. By applying various estimates without recognizing the constraints (such as surface location restrictions, the fact that not all pools below the surface will be discovered, and the economic realities of small pools), such a flawed study would surely overstate the future supply availability and hence production projections.

The purpose of depreciation is to recover investment over a reasonable period of time. I do not believe that it would be in the public interest to set a depreciation rate for GTN based upon sources of supply, the availability of which to GTN and its customers is highly uncertain. Therefore, I think it would be unreasonable to include in the economic life evaluation other gas resources, such as those outside of the Rocky Mountain region, from which GTN's shippers only theoretically may draw.

Q: What is the effect of GTN Witness Haessel's gas supply study of the WCSB and the study of the U.S. Northern Rocky Mountain Region on the determination of the economic life of GTN facilities?

A: The effect of GTN Witness Haessel's gas availability forecast on GTN's pipeline system is that large sections over time will become underutilized as shown in Schedule No. 9 of Exhibit No. GTN-24. This will be somewhat mitigated by the potential for Rocky Mountain gas to enter GTN's system. However, even this source of gas will eventually begin to decline, as shown in the accompanying Northern Rocky Mountain gas supply studies. This decline in production directly affects the utilization of GTN's mainline transmission facilities. GTN Witness Haessel's analysis of the Western Canada gas supplies for export indicates, under his high gas supply scenario, that, by the year 2025, the volumes available in the WCSB supply region, including Mackenzie Delta gas as well as coalbed methane, will have decreased to approximately 13 percent of the 2005 levels. And, by 2034 that supply region will not produce enough gas to satisfy Canadian requirements. The base case is worse; by 2021 there is no gas to export from Western Canadian sources. The fall-off in GTN's other supply area, the Rocky Mountain region, is also significant. Such fall-offs in the availability of natural gas from these gas supplies would certainly affect the utilization of GTN's mainline facilities.

Q: How did you determine that the end of the economic life would be most reasonably represented by a 30-year period, from the beginning of 2005?

A: The end of the economic life of 30 years is based upon the following factors:

- GTN Witness Haessel's WCSB base gas supply case indicating no exportable gas supply in 30 years.
- GTN Witness Haessel's WCSB high gas supply case indicating over 50 percent reduction in current availability in 30 years.
- Mr. Feinstein's Rocky Mountain gas supply indicating nearly 50 percent reduction in current availability in 30 years.
- More capacity, *i.e.*, pipelines, will be necessary to produce Rocky Mountain gas supply, resulting in a long-term reduction in share of gas availability per Mcf of constructed pipeline capacity.
- High degree of consensus of a downward trend in WCSB conventional supplies – *e.g.*, current declines in size and productive availability.
- Uncertainty of long-term unconventional gas supplies, *e.g.*, CBM, tight gas and shale gas.

- Uncertainty of the flow of Alaskan gas through GTN's system.

Q: What is the effect of the determined gas supplies on pipeline facilities?

A: Because of the fall-off in the supply from GTN's traditional gas supply areas, significant amounts of pipeline facilities would become underutilized. Specifically, GTN Witness Haessel's studies indicate gradual, yet steady and significant decreases in the supply of gas from the WCSB area over the period 2006 to 2035. Similar fall-offs also occur in the Rocky Mountain supply areas. However, even this source of gas will eventually begin to decline, as shown in the accompanying Northern Rocky Mountain gas supply studies. This decline in production directly affects the utilization of GTN's mainline transmission facilities. GTN Witness Haessel's analysis of the Western Canada gas supplies for export indicate, under his base gas supply scenario, that, by the year 2025, the volumes available in the WCSB supply region, including Mackenzie Delta gas as well as coalbed methane will have decreased to approximately 35 percent of the 2006 levels. And, by 2035 that supply region will not produce enough gas to satisfy Canadian requirements. The fall-off in GTN's other potential supply source, the Rocky Mountain region is also significant. Such fall-offs in the availability of natural gas from these gas supplies would affect the utilization of GTN's mainline facilities.

Q: What are the results of your analysis of the economic life of GTN's present facilities?

A: As a result of my analysis of GTN's system operation, the nature of its markets, and the gas supply comprising its throughput, I determined the economic end life to be 30 years. This conclusion is based upon underutilization of certain of its facilities ("major retirements") due to depletion of its traditional gas supply sources. It is also due to the uncertainty of market retention due to competitive pressure from other sources.

Q: What are major retirements, and how do you conceptualize them with respect to the economic life?

A: Major retirements are severely underutilized facilities due to economic forces (rather than physical forces), such as gas supply depletion causing underutilization and changes in system operations.

Q: How did you determine 26 years as the average remaining economic life for GTN's pipeline facilities?

A: I determined major underutilization that would take place along GTN's system from the results of GTN Witness Haessel's WCSB gas supply study and the studies I performed of the availability of Rocky Mountain gas. The results are shown on Schedule Nos. 9 and 10 (WCSB) and Schedule No. 11 (Northern Rocky Mountain area) of Exhibit No. GTN-24. Basically, I established candidates for retirement in direct proportion to the decline in availability. I performed the calculations for each supply area and how they would affect the GTN pipeline system.

Q: How did you determine these "major retirements?"

A: I determined the effect that the combined supply areas would have on GTN's facilities by assuming that the percentage decline in supply would result in underutilization of GTN's facilities at the same extent as other pipelines exporting volumes from Western Canada. The approach I took was to establish major retirements or candidates for major retirement from underutilization of pipeline facilities in direct proportion to the decline in gas availability.

Permanent underutilization of GTN's facilities shortens the economic life of the pipeline and will lead to the eventual physical retirement of various facilities prior to the final system closure or abandonment date. My economic life reflects the projected underutilization of GTN's facilities due to declines in throughput. It is not necessary that an actual physical retirement take place in order to qualify a facility as underutilized in the determination of the economic life of the GTN system. However, certain facilities, such as compressor station equipment may actually be physically retired at points in time closely following underutilization. For example, most of GTN's compression facilities are expected to be retired before the final closure date. Nevertheless, economic life is based upon a forecast of the permanent underutilization of GTN's facilities. Fairness and intergenerational equity support the concept of projecting declines in throughput to establish permanent underutilization as a part of calculating economic life. Intergenerational equity is nothing more than directly relating cost responsibility to those shippers who will use the pipeline facility. For example, when a compressor unit or a loop line is no longer used on a regular basis, other than for repair or emergency purposes, it should be fully accrued (depreciated). However, such a facility may linger in service for a period of time as an emergency back up; it may be put in mothball status waiting for the appropriate time to physically retire the facility when abandonment is formally approved; or it may simply not be used because it is a component of a larger facility, a portion of which is still used and useful.

An illustration of my underutilization of facilities concept, sometimes referred to in this case as “major retirements”, and the economic life concept is found in Schedule No. 12 of Exhibit No. GTN-24.

The importance of this concept is avoiding a situation where depreciation dollars per unit of gas service become so high as to be unreasonable. This occurrence can only be prevented by taking future declines in gas supply availability into account as a part of calculating economic life.

Referring to the cost responsibility concept, one objective in depreciation is that one generation of ratepayers should not pay an inequitable portion of depreciation with respect to another generation of ratepayers.

This same depreciation concept was supported by the Commission in its orders concerning cost responsibility for unused capacity of new pipelines. That is, a generation of ratepayers who use a portion of a pipeline’s capacity should not bear responsibility for any unused capacity.

Q: Does underutilization or major retirements actually take place in the gas pipeline industry?

A: Yes. It is my experience, in analyzing the operation and actual retirements of pipeline properties, that such situations in varying degrees take place. In market areas, loss of customer base causes underutilization and eventual retirement from such economic forces. In supply areas, depletion of gas reserves and competition are typical causes of underutilization and eventual retirement. For example, offshore Gulf of Mexico facilities are constantly being retired. Further, on March 9, 2000, Trunkline Gas Company, after exhibiting underutilization on its south Louisiana to Tuscola, Illinois mainline system, retired an entire 700-mile loop line.

The reason that the pipeline loop was retired is because of the severe underutilization on Trunkline's mainline system. As another example, Trans-Northern Pipelines Inc. sought, and was granted, abandonment authority by the NEB for its entire Don Valley Lateral to Toronto Harbour. That decision was made as the facility was in a "serious deficit position" due to reduced throughput.

Q: Are there any other examples of major retirements related to supply or throughput deficiencies?

A: There are other examples of major retirements. Florida Gas Transmission Company ("Florida Gas") has experienced major retirements of pipeline and compressor facilities in its South Texas Gulf Coast production area due to decreasing gas availability. Specifically, Florida Gas has retired: (1) pipeline facilities located south of its Compressor Station No. 2, and (2) pipeline facilities and Compressor Station No. 2, both located south of Station No. 3 and the Matagorda Offshore Pipeline System interconnect. While the facilities were sold for $2.3 million, a fraction of their replacement cost or original cost, the fact remains that they were no longer useful to Florida Gas' operations.

Another example, but on even a larger scale is the abandonment by CenterPoint Energy – Mississippi River Transmission Corporation ("MRT") (Docket No. CP04-334-000) of 307 miles of its Main Line No. 1, consisting of 22-inch diameter pipeline and other equipment such as compressor engines. While, in the case of this facility, the system was old and, in many places, in need of upgrading, other portions were not old. This facility was underutilized. An indication of its underutilization is that it was not replaced by MRT.

Q: Did you examine the economic life of GTN's transmission assets from any other perspective?

A: Yes. I also simulated a realistic relationship between GTN's existing facilities and the amount of future gas available in the Rocky Mountain area. The Rocky Mountain area is unique among the lower 48 gas producing states with respect to pipeline capacity. It represents the last frontier for lower 48 gas supplies and new pipeline take-away capacity.

Expanding production in this area has occasionally outpaced the installation of new interstate take-away capacity. The Commission's present policy is to encourage and expedite, if possible, applications for new capacity, specifically, in the Rocky Mountain area. Surplus gas availability in the future as compared to the existing productive capacity in the Rocky Mountain area is forecasted and shown on Schedule No. 6, page 1, of Exhibit No. GTN-24.

With the above in mind, my main assumption in the simulation of a realistic relationship between GTN's existing facilities and the amount of gas available in the Rocky Mountain area, is that any surplus or excess productive capacity will be attached and transported to market by newly constructed pipeline capacity. That is, the surplus productive capacity will not be husbanded in order to wait for existing pipeline capacity to open up. Therefore, GTN's existing facilities will be limited only to future productive capacity that will fill the capacity of its pipeline system. Thus, GTN's share of the productive capacity of produced gas in the Rocky Mountain area is 13.03 percent of the total, as of 2003. However, as the annual production in the area increases, and new pipeline capacity is built, GTN's share of total production decreases. When the area's production peaks, GTN's share of the total supply decreases to 11.52 percent. The profile of GTN's throughput related to its existing capacity forecasted into the future using the area-wide productive capacity as developed in Schedule Nos. 5 and 6 of Exhibit No. GTN-24.

The result of the simulation indicates that, by 2030, the amount of gas available for transport through GTN's existing system will be less than one-third of what it is today. These results are conservative, as the forecast of future gas availability from the Rocky Mountain area includes 18 percent more potential gas supplies than the PGC's most recent estimates.

Another aspect of the economic life component in the determination of depreciation is the capital recovery objective. In addition to providing an adequate opportunity to recoup the investment in pipeline facilities and appropriately matching revenues to the costs of providing gas transportation services, which have already been described, another important factor in establishing depreciation rates is the long-term fairness of the depreciation component. Specifically, the objective in this regard is to minimize intergenerational inequities in the consumption of service value (depreciation).

An important part of regulatory depreciation is the need to maintain long-term intergenerational equity among users of GTN's pipeline system. If the recovery of invested capital is unnecessarily deferred, an unfair burden would be placed upon future customers. Inherent in regulatory depreciation is the premise that the ratepayers who are using the pipeline system should pay for its use. If GTN's primary depreciation rates remain approximately the same as its current rates, further deferral of the recovery of invested capital will either increase costs to future users of the system or expose GTN to potential under-recovery beyond the value of the service that will be consumed in that period.

Thus, as facilities become underutilized due to declining throughput, a depreciation rate which does not take such declines into consideration would result in inequitable treatment of future ratepayers, as the unit cost of depreciation would be many times higher than that for current ratepayers. This is an important concept that must be considered.

The Court of Appeals for the District of Columbia in the landmark *Memphis* decision on depreciation emphasized, "Even assuming continued serviceable life, declining use of pipeline facilities might conceivably lead in future years to depreciation dollars per unit of gas so high as to be unreasonable." *Memphis Light, Gas and Water v. FPC, 504 F.2d 225, 234 (D.C. Cir. 1974).*

Q: Mr. Feinstein, do any other pipelines that rely upon WCSB gas supplies employ 25 to 30 years as the economic life to determine depreciation?

A: Yes, the National Energy Board of Canada authorized depreciation rates for TransCanada, which were directly developed from a 25-year economic life.

Q: Are there examples of retirements for reasons other than supply or throughput deficiencies?

A: Yes. Wear and tear is probably a leading cause of retirement due to physical forces on GTN's system. Compressor equipment and meters are subject to such a physical force of retirement.

Population growth is directly and indirectly responsible for many of the maintenance-type capital improvements and related interim retirements on the GTN system in various areas. As population density increases, and communities grow closer to GTN's pipeline, Class Location changes often dictate the installation of thicker walled pipe. In addition, the growing population requires improvements to the infrastructure to support the additional inhabitants. These infrastructure improvements often take the form of highway widening or the extension or expansion of other utility facilities, which would require the relocation of GTN facilities, which were constructed adjacent to existing roadways or in utility easements to minimize environmental disturbance.

Q: How have you evaluated and included the increment of negative salvage as it relates to plant retirements?

A: As I stated earlier in my testimony, net salvage is an integral element in the analysis of depreciation. If the net salvage is positive, then the difference between gross plant in service and the reserve for depreciation (referred to as net plant) must be decreased in order to compensate for a smaller depreciable base to be recouped. However, if the net salvage is negative, the depreciable net plant must be increased in order to allow for the recoupment of such a capital cost component.

The vast majority of the items retired during the most recent 10-year period were transmission plant facilities. Upon close analysis, the difference between the gross salvage value and the cost of removal was clearly negative. That is, for many retirements, the cost of removal exceeded the gross salvage value. I estimated that the average net salvage, as a percent of the cost of the facility retired for the period ranged from negative 5 to negative 20 percent. Thus, on average, for every dollar of plant retired, the company is actually "out-of-pocket" certain funds, without recognition of negative salvage costs.

Q: Did you build negative salvage into your depreciation calculations?

A: No, I did not. I treated negative salvage separate from the depreciation calculation. The depreciation calculation is for capital recovery only.

THE DETERMINATION OF DEPRECIATION FOR THE GTN SYSTEM

The Straight Line Remaining Life Approach

Q: How did you apply the 26-year economic life to the depreciation model?

A: The 26-year economic life plays a key role in the determination of the average remaining life ("ARL"). It represents the average year of the final recoupment of GTN's investment in its facilities as an overall group. The best way to describe the relationship of the economic life to the ARL is to overlay it with the normal retirement survivor curve.

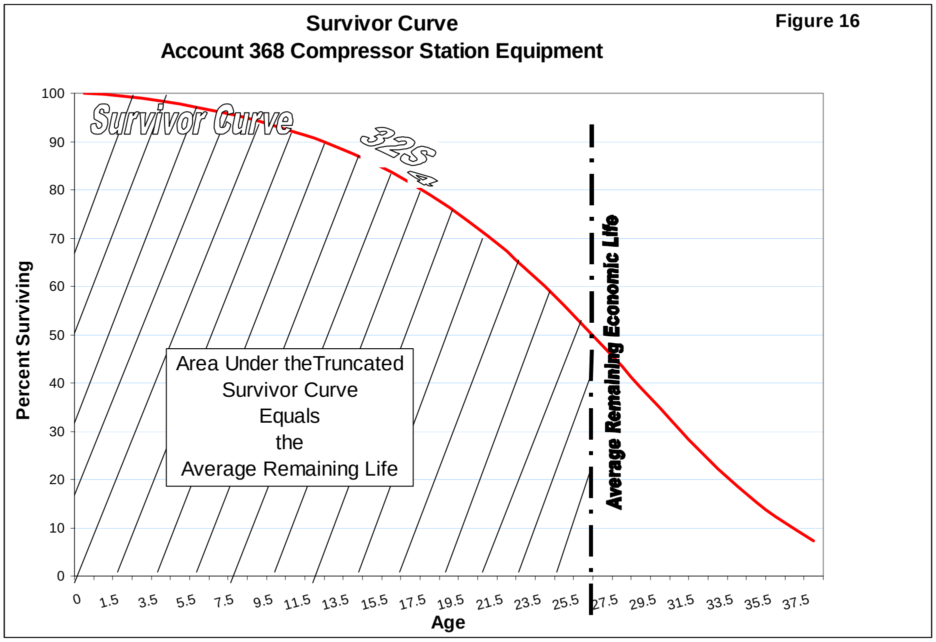
Q: How did you determine the normal retirement survivor curve?

A: The survivor curve represents the pattern of annual normal retirements that will occur over time for property of a certain character. I determined the normal retirement curve for each of GTN's transmission accounts. For example, I determined that Account 367 (Mains) has an average service life of 60 years, with an R_1 survival pattern. Mains make up about 65 percent of GTN's mainline transmission system. My analysis began with an Iowa-type survivor curve determination utilizing the Simulated Plant Record ("SPR") method. The SPR is a method, which, depending upon the quality of the plant balance and retirement data, can accurately portray a survivor curve based upon historical retirements. There are two methods of determining a survivor curve from historical plant data. The SPR method is one. The other is the actuarial method. The actuarial method determines a survivor curve based upon the assembly of historical retirements categorized by the year in which it first went into service. The SPR method establishes a survivor curve based upon the curve which best compares to the actual plant retirements and surviving plant balances. One important point concerning a survivor curve developed from historical retirements is that it is only as good as the data it assembles. For example, heavy reliance on the shape and average service life of a "stub curve" would not be prudent. A "stub curve" may represent only 10 percent as the amount of plant retirement experience. This is not enough from which to conclude a specific curve. In such cases, I also rely upon an analysis of the type of equipment, its usage and condition, as well as its age and survivor curve retirement patterns that are typical in the industry of such facilities. For the Mains account, the 60 R_1 survivor curve is shown on Exhibit No. GTN-24, Schedule No. 3. I determined the survivor curve and resulting average service life which best applies for each of the other accounts as follows:

Account No.	Description	Average Service Life	Survivor Pattern
365.2	Rights-of-way	60	R_1
366	Structures	34	R_2
368	Compressor Sta. Equip.	27	R_1
369	Meas. & Reg. Sta. Equip.	24	R_2
370	Communication Equip.	10	R_1

Q: What is the next step in your analysis?

A: When the economic life is applied to the survivor pattern, future normal retirements beyond 26 years are not relevant. The ARL is determined by integrating or calculating the area under the truncated survivor curve. This calculation is shown in conceptual form in Figure 16 of Exhibit No. GTN-24.



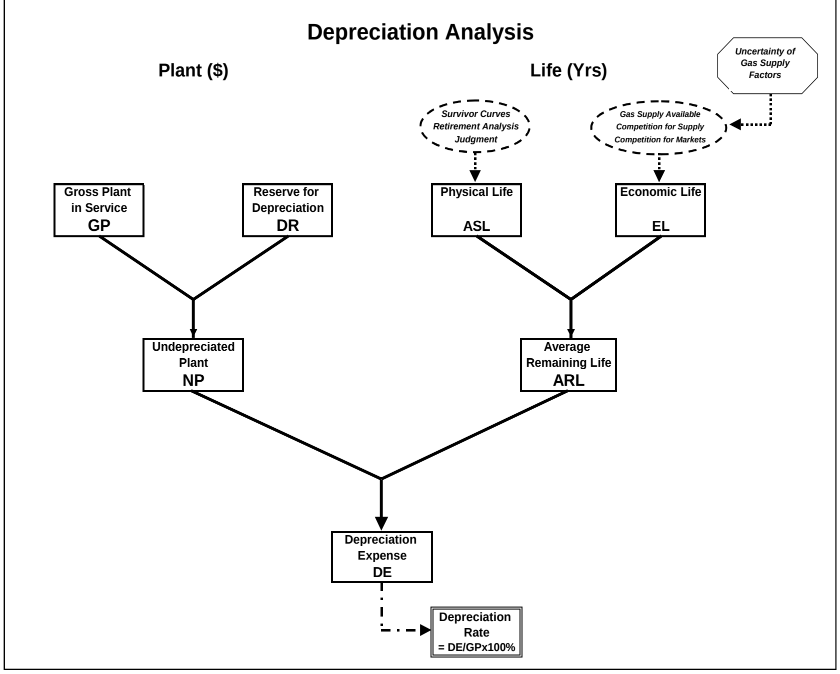
For the transmission mains, the ARL was determined to be 24.3 years. This is shown on Schedule No. 14 of Exhibit No. GTN-24. Similar determinations were made for the rest of the accounts in the transmission function.

Determination of Depreciation Rate for GTN's Transmission Plant

After determining the individual ARLs for each account, I then divided each ARL into the difference between the depreciable plant and the accumulated reserve for depreciation, thus arriving at the indicated depreciation expense. The indicated depreciation expense for each account was totaled. This then is the indicated depreciation expense for the total onshore transmission plant. I performed this operation for the years 2006 to 2008. This is shown on Schedule No. 14 of Exhibit No. GTN-24. The indicated depreciation rate for GTN's transmission plant is 2.76

percent. The procedure in determining the depreciation is illustrated in the diagram shown below in Figure 17 of Exhibit No. GTN-24.

Figure 17



Q: How did you reflect near-term plant additions and retirements?

A: In order to reflect near-term plant additions and retirements for purposes of depreciation rate stability, I performed a three-year depreciation rate determination, employing plant additions and retirements for 2006 through 2008. This also is shown on Schedule No. 14 of Exhibit No. GTN-24. The indicated depreciation rate was then calculated by dividing the total indicated 3-year expense by the depreciable plant.

The gross depreciable plant as of December 31, 2005 was provided to me by the company as their end of year booked plant. With respect to actual and very near-term additions of plant, I estimated various amounts. Further, near-term retirements also were estimated.

Q: How did you determine the December 31, 2005 reserve for depreciation for the transmission function?

A: The December 31, 2005 reserve for depreciation for the transmission function was provided to me by the company. GTN, like most interstate gas pipeline companies, books depreciation on a functional basis. Therefore, I determined a theoretical reserve for depreciation for each account for calculation purposes, all the while maintaining the actual total booked reserve figure. The depreciation rate determination in summary form as compared to its existing rates is shown on Schedule No. 1 of Exhibit No. GTN-24.

Negative Salvage Rate

Q: Please explain the term "negative salvage."

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

Q: What is a negative salvage rate?

A: A negative salvage rate is the annual rate, as a percent of the gross plant subject to retirement that will accrue enough funds in an orderly and fair manner to cover the cost of retirement. I used the same straight line remaining life method that I employed to determine the depreciation rates to accrue negative salvage funds.

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

Q: What determines the manner in which abandonment takes place?

A: Authorization under section 7 of the Natural Gas Act for the abandonment of natural gas facilities provides for actions that require an environmental assessment by the FERC (S*ee* 18 C.F.R. § 380.5 (2005)). It is this assessment which describes the manner in which the abandonment is to take place. This places a monetary burden on GTN to decommission its facilities correctly and restore the land to its original condition.

Q: In your view, will GTN's facilities eventually be decommissioned?

A: GTN's pipeline facilities will have to be decommissioned. Pipeline facilities eventually wear out, become obsolete or uneconomic. This fact is demonstrated by my plant retirement and survivor curve analysis, which reflects retirements due to physical causes. Gas supply and facility utilization studies reflect retirements that occur due to specific pipeline facilities becoming obsolete, redundant or otherwise unnecessary. At some point, each pipeline reaches the end of its economic life.

Q: What did you calculate GTN's negative salvage rate to be and how did you determine that rate?

A: I analyzed GTN's historical retirements, conversed with company personnel and reviewed the experiences of other companies. I found that the cost of removal will out-pace any gross salvage received for such retirements. Based on that analysis, I determined net negative salvage values vary with each type of facility and age at retirement.

Q: Can you provide a more detailed description of your determination?

A: My determination of the appropriate negative salvage rate began by familiarizing myself with GTN Witness Dan King's terminal net salvage study for GTN.

My determination of the negative salvage rate is a combination of two distinct annual negative salvage accrual calculations. The negative salvage rate is the quotient of the annual negative salvage accruals, divided by the gross plant. I determined the negative salvage base for the ongoing normal, interim retirements separately from the major retirements and final closure, because each has an associated average life different from the other.

Normal retirements will occur from 2006 for a period of an average of 26 years. The remaining facilities will be subject to the final closure at the end of the 26-year economic life. I determined the interim retirements for each plant account from the same survivor curves that I developed earlier for depreciation purposes. Recall that the survivor curve is actually a graphic representation of normal retirements over a period of time. The 26-year period of interim retirements for each account is shown on Schedule No. 16 of Exhibit No. GTN-24. I combined all the interim retirements and determined an average remaining life of 16.38 years that would apply as the average period of time to accrue the negative salvage for the interim retirements. This is also shown on Schedule No. 16 of Exhibit No. GTN-24.

After I determined the future annual normal or interim retirements for each account that would be affected by negative salvage, I then applied various net negative salvage values ranging from 2 to 35 percent factors to the anticipated facility retirements. These factors are supported by my analysis and observation of GTN's historical retirement experience referred to earlier, discussion with operating, personnel and the experience of other pipeline companies.

I adjusted GTN Witness King's total negative salvage estimate to reflect the fact that some of the facilities will not be retired at final closure, but as normal (interim) retirements over a period of time. The difference between GTN Witness King's negative salvage estimate and that for the interim retirements represents the negative salvage at the final closure, or terminal net salvage. This is shown on Schedule No. 17 of Exhibit No. GTN-24. The 26-year average economic life was applied to the final closure estimate. I then created a composite of the 26-year accrual period for the final closure along with the 16.38-year accrual period for the interim retirements to arrive at an average period of 23.11 years. This is shown on Schedule No. 18 of Exhibit No. GTN-24. The 23.11 years is the result of direct weighting of the net negative salvage cost and the number of years to retirement. When they are reciprocally weighted, the result is 22.10 years. I employed direct weighting in order to be consistent with other direct weighting factors.

Q: Can you describe the mathematical calculations used to determine the negative salvage rate?

A: Schedule No. 19 of Exhibit No. GTN-24 shows the calculation of the negative salvage rate for GTN's transmission plant. I divided the estimated amount of negative salvage by the accrual period of 23.11 years. I then divided that quotient by the transmission plant in service to arrive at 0.74 percent.

Q: How do you recommend net salvage be reflected for accounting purposes?

A: I recommend that GTN establish a sub-account for negative salvage in Account 108, Accumulated Provision for Depreciation of Gas Utility Plant.

Q: What is the reason for creating this sub-account?

A: A sub-account allows the negative salvage reserve to be reviewed periodically with ease.

Q: Based on your analysis, what did you determine GTN's net negative salvage for each dollar of plant retired to be?

A: Analysis of GTN's operations, facility configuration, and actual retirements indicates future retirements will result in a cost of removal in excess of any gross salvage for such facilities. I expect that GTN will average approximately 5 percent net negative salvage for each dollar of plant retired.

Depreciation Rate for General Plant

Q: What accounts make up the general plant?

A: The general plant is made up of the following accounts:

Account No.	Description
391	Office Furniture & Equip.
392	Transportation Equipment

394	Tools, Shop and Garage Equip.
396	Power Operated Equipment
397	Communication Equipment

Q: Please explain how you determined the average service life and why you made a separate determination for each individual account.

A: I determined the appropriate average service life that best applies to each type of the equipment in the individual accounts. These lives, along with their respective depreciation rates, are shown on Schedule No. 15 of Exhibit No. GTN-24. These average service lives were developed based upon analysis of the properties in each account. My analysis was also based on discussions with GTN personnel, as well as the experience of similar properties of other pipeline companies. The determination of the above depreciation rates differs from the mechanics employed for the transmission plant. Because of the high turnover rate of the facilities in the general plant, the whole life method was used to determine depreciation instead of the remaining life method. The reason for this treatment is that the turnover rate for general plant facilities is so much higher than that of the transmission plant.

Q: Would you please summarize your testimony?

A: The purpose of my testimony is to determine the just and reasonable rates of depreciation for the depreciable facilities belonging to Gas Transmission Northwest. To do so, I have analyzed the tangible properties and operations of its pipeline system and estimated its average remaining life. I concluded that the economic end life of GTN's pipeline system is 30 years, and I developed a composite depreciation rate of 2.76 percent for transmission plant. Further, I determined a separate rate of 0.74 percent to cover the accrual for negative salvage expense.

Q: Does that conclude your testimony?

A: Yes.