Model Documentation
Natural Gas Transmission and Distribution Model (NGTDM)

of the National Energy Modeling System

Volume II: Model Developer's Report

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Table of Contents

I. Introduction

To partially fulfill the requirements for "Model Acceptance" as stipulated in EIA Standard 91-01-01 (effective February 3, 1991), the Office of Integrated Analysis and Forecasting has conducted tests of the Natural Gas Transmission and Distribution Model (NGTDM) for the specific purpose of validating the forecasting model. This volume of the model documentation presents the results of "one-at-a-time" sensitivity tests conducted in support of this validation effort. The test results are presented in the following forms:

- o Tables of important model outputs for the years 2000 and 2010 are presented with respect to change in each input from the reference case.[1]

- o Tables of percent changes from base case results for the years 2000 and 2010 are presented for important model outputs.

- o Tables of conditional sensitivities (percent change in output/percent change in input) for the years 2000 and 2010 are presented for important model outputs.

- o Finally, graphs presenting the percent change from base case results for each year of the forecast period are presented for selected key outputs.

To conduct the sensitivity tests, two main assumptions are made in order to test the performance characteristics of the model itself and facilitate the understanding of the effects of the changes in the key input variables to the model on the selected key output variables:

1. responses to the amount demanded do not occur since there are no feedbacks of inputs from other NEMS models in the stand-alone NGTDM run.

2. All the export and import quantities from and to Canada and Mexico, and liquelied natural gas (LNG) imports and exports are held fixed (i.e., there are no changes in imports and exports between the reference case and the sensitivity cases) throughout the forecast period.

In addition to the model documentation requirements, tests conducted for the Model Developer's Report are designed to partially satisfy recommendations from the 1991 Model Quality Audit of the Gas Analysis Modeling System.[2] In particular, the tests presented in this report are designed to satisfy the requirement for conducting demand sensitivity tests. Recommendations to conduct historical simulations ("backcast experiments") will be addressed at a later date and will be included in updates of this report.

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[1]The reference case is derived from a stand-alone run of the Natural Gas Transmission and Distribution Model. This model run used a restart file from a draft Annual Energy Outlook (AEO) 1995 base case run (AEO95B.D1009941) for model inputs. The stand-alone NGTDM run is different from the integrated National Energy Modeling System (NEMS) run in that the integrated run balances energy supply and demand while accounting for the economic competition between the various fuels and sources. The stand-alone NGTDM run is used to test the performance characteristics of the NGTDM itself, whereas the integrated NEMS run is used to produce the AEO 1995.

[2]The Gas Analysis Modeling System (GAMS) of the Intermediate Future Forecasting System essentially served the same purpose as the Natural Gas Transmission and Distribution Model in the National Energy Modeling System. In 1991, EIA conducted a Model Quality Audit of the GAMS. The major recommendations of that audit (see "Model Quality Audit: Gas Analysis Modeling System (GAMS)", prepared by William D. Robinson, Office of Statistical Standards, December 1991) were that historical simulations should be conducted to identify the source of bias in the wellhead price projections, and regional demand sensitivity tests should be conducted if a new regionally disaggregated model were to be developed.

The report documents the performance of the version of the NGTDM used to produce the Annual Energy Outlook 1995 (AEO95) (NEMS95 is the model acronym). Although the basic model structure is similar to that presented in the AEO94 version of the NGTDM, a number of changes and corrections have been made to the model that change the response of the model in the sensitivity tests presented in this document. Model methodology documentation (Volume I of the documentation series) presenting the algorithms, assumptions and input data for this version of the model will be available early in 1995.

Following this introductory section, a discussion of the feasible region and domain of convergence of the NGTDM is briefly presented, the methodology used in conducting the tests is discussed, and the sensitivity results are presented. Graphs presenting selected results of the sensitivity analyses over the full forecast time period are presented in Appendix A.

II. Feasible Region and Domain of Convergence of the NGTDM

As presented in Volume I of the NGTDM documentation,[3] the NGTDM consists of four major components. The Capacity Expansion Module (CEM) and Annual Flow Module (AFM) use linear programs to solve for a gas supply and demand equilibrium while minimizing transportation costs subject to a set of constraints. The Pipeline Tariff Module (PTM) is an accounting model consisting of a set of accounting and econometric relationships. Finally, the Distributor Tariff Module (DTM) is a simple accounting module. What is known about the feasible region for the two linear programs is discussed below. This discussion focuses on the importance of the inputs that were varied as part of the sensitivity tests. Finally, a discussion of the domain of convergence for the accounting modules is presented.

Capacity Expansion Module Linear Program

Given the computational complexity of the National Energy Modeling System it is highly desirable to minimize the opportunity for system failure attributable to an infeasible linear program. To reduce the possibility of an infeasible solution, the CEM has a "backstop" supply that is available at every demand node. A very high price is associated with this supply so that it is only used when the alternative is an infeasible solution. Use of backstop to satisfy core[4] market demand is a serious error and must be resolved before proceeding with an analysis. The benefit of the backstop is that (provided only small amounts are used or if the use is limited to selected years in the forecast) useful information can still be obtained from a NEMS run so development of an integrated forecast can proceed despite the averted infeasible solution within the CEM.[5]

Despite the backstop supplies, a number of conditions may exist that can result in an infeasible CEM solution. The conditions that have caused this include:

- o Demand is so low that the minimum amount of production that the model assumes must be supplied is greater than the demand.
- o Demand is so high that the supply available (including backstop) falls short of demand.
- o Capacity requirements exceed the upper bound on the amount of capacity that can be added to any one arc.

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[3]Energy Information Administration, "Natural Gas Transmission and Distribution Model of the National Energy Modeling System", Volume I, Washington, D.C., DOE/EIA MD-062, February 1994.

[4]The term "core" refers to natural gas customers that require firm (or near firm) gas transportation arrangements. For modeling purposes, this category includes all residential and commercial customers, the industrial market (excluding customers whose predominate use of the fuel is combustion in a boiler), and central station electric generators (excluding the combustion turbine and dual-fired steam boilers). The term "noncore" refers to all other natural gas customers outside of the core market. The noncore market is assumed to include interruptible service customers and customers who transport their gas using short-term release market capacity agreements.

[5] Interpreting the model outputs when backstop is used in the solution is an art that requires a significant amount of expertise. The ability to analyze and interpret the outputs from an LP solution employing backstop is likely to be beyond the ability of an occasional user of the model.

- o A minimum flow constraint is violated because large year-to-year reductions in flow patterns are required to keep the network in balance.

Annual Flow Module Linear Program

Similar to the CEM, the Annual Flow Module (AFM) also employs a backstop supply to reduce the possibility of the linear program being infeasible. The purpose of the backstop is the same as in the CEM. Infeasible solutions are more common in the AFM because the AFM does not have the ability to add pipeline capacity. Additionally, the possibility of an infeasible solution in the AFM is greater because the pipeline capacity constraints provided by the CEM to the AFM are developed based on an expected set of demands. The demands observed in the AFM may differ from those used in the CEM. Infeasible solutions in the AFM attributable to the following conditions have occurred:

- o Conditions require a supply and demand imbalance along any point in the network such as (1) total demand less than the minimum supply level or (2) total demand is greater than supplies (including backstop).

- o Limited supplies or the level of demand causes a minimum flow to be violated.

- o A pipeline capacity constraint is violated because pipeline capacity into a region is inadequate to meet demand at a downstream node or pipeline capacity exiting a region is inadequate to move a minimum amount of supply out of an upstream region.

- o An inconsistency in a set of technical factors (such as the weather factor or load shape parameter) between the CEM and AFM causes conflicts between effective pipeline capacity and flows.

Domain of Convergence for Pipeline and Distributor Tariff Modules

The Pipeline Tariff Module and Distributor Tariff Module always produce a unique solution because of their direct (rather than iterative) solution algorithms and because all of the functions in the modules are continuous and differentiable in their domain of applicability (that is, when "reasonable and consistent inputs" are provided to the modules). Existence and convergence are not issues of concern. Some of the model inputs may be correlated. So if inconsistent pairs of such inputs are chosen, the model while solving, may produce useless results. Similarly, all model inputs have limits on the reasonable range of values (e.g. demands must be nonnegative). When the model is run in a stand-alone fashion, the user must be certain that the inputs are consistent and credible.

An issue that is very important to the convergence properties of the Pipeline and Distributor Tariff Modules is that within any year of the forecast, revenues to the pipeline and distributor industries are never reconciled with their revenue requirements. Therefore, in a particular year, the revenues implied by the resulting transmission and distribution markups may deviate from the revenue requirement determined by each module for that year. This approach is consistent with general industry practice, where tariffs are set prospectively based on a test period that may be adjusted for known changes in operating conditions. Individual business units, utility commissions, and customers may track a pipeline's or distributor's performance relative to its revenue requirement to determine if it is appropriate to initiate a rate case because of over- or under-collection of revenues. However, future rates are not explicitly adjusted for past performance because of the prohibition against retroactive rate making.

III. Methodology

This section describes how the selected input variables are perturbed and used for the sensitivity tests. It also presents the analysis approach developed to examine the impact of an input variation on the model's key output variables.

Input Variables

The selected input variables are categorized into two types of groups: demand inputs and technical parameters. These input variable groups, which impact specific sets of output variables, are listed as follows:

Group 1: Demand Inputs[6]

- National Residential demand
- East North Central Residential Demand
- Core industrial demand
- Noncore industrial demand

Group 2: Technical Factors

- Weather factor (reserve margin) in the Capacity Expansion Module
- Cost of new capacity exiting the Mountain Region in the Capacity Expansion Module
- Compressor station fuel efficiency (shrinkage)

VARIATION OF INPUT VARIABLES:

Sectoral gas demands, and technical planning and operational factors are major drivers that impact the NGTDM output results. The selected percentage changes in input variables vary depending on the types of input variables and on the degree to which the NGTDM performance characteristics behave, as presented below.

The base level demands for each of the demand inputs are presented in Figure 1, Appendix A. A significant amount of experimentation was required prior to defining the exact specifications of the demand sensitivity

[6]A demand representation (either in the form of a price quantity pair or a step function) is an input to the NGTDM. When operating in an integrated mode, the NGTDM solves for the level of consumption at the market equilibrium price. In the "stand-alone" configuration employed in conducting the sensitivity tests, the demand is completely inelastic. Inelastic demand requires that the consumption level equals the demand at the market equilibrium price. Rather than switching back and forth between the terms "demand" and "consumption" (based on whether the reference is to the model input or model output), the term "demand" is used throughout the report since they are equal in the stand-alone configuration.

tests. To obtain a measure of the model's performance required that the change in demand be sufficiently large to require changes in key model outputs. Past experience with the model has demonstrated that large changes in demand may cause the model to be infeasible. This problem is very likely to happen when the change in demand is abrupt (e.g. a 5 percent change in demand in any one year). Therefore, in conducting the demand sensitivities, changes in the demand levels are phased-in over the forecast period and the changes are not introduced until 1996. The delay in introducing the demand changes allows sufficient time for the model to adjust the capacity builds. For example, the 1996 demand is 0.5 percent greater or less than the reference level, while the 1997 demand is 1.0 percent greater or less than the reference level. The growth (decline) rate for demand is constant throughout the forecast period. In this example, the change in demand from the reference level in 1998 is 1.5 percent, in 1999 the change is 2.0 percent and in 2000 the change is 2.5 percent. In 2010, the change in demand is 7.5 percent.

National Residential demand Gas demand in the residential sector represents the second largest end-use sector for natural gas consumption in the United States, representing 25 percent of the total gas consumption in 1993. A small change in gas demand in this sector has relatively large impact on the natural gas industry because the demand is highly seasonal and requires firm pipeline capacity. The impact of a 0.5 percent incremental (or decremental) change in residential gas demand per year from 1996 through 2010 is explored. With this adjustment, the residential demand level increases (decreases) by approximately 125 billion cubic feet in 2000 and 367 billion cubic feet in 2010 relative to the reference case.

East North Central residential demand The perturbation in residential gas demand in one region has an impact on the national market equilibrium for natural gas. A model run to test this interaction produced some anomalous results in the Gas Analysis Modeling System (GAMS). To demonstrate the performance of the NGTDM under similar conditions, this sensitivity test increases incrementally (decreases decrementally) residential gas demand in the East North Central Region (Region 3) by 0.5 percent per year from 1996 to 2010. Region 3 was chosen for the sensitivity test because the region has the largest share of residential natural gas use of all the Census Divisions (31 percent of residential gas consumption in 1993). This region's residential demand level increases (decreases) by approximately 38 billion cubic feet in 2000 and 108 billion cubic feet in 2010 relative to the reference case.

Core industrial demand Industrial gas demand is the largest natural gas consumption share in the United States (37.7 percent in 1993 as reported in the *AEO95*). Core industrial gas demand, which accounted for 55 percent of the industrial gas demand in 1993, is less seasonal than residential demand and in the reference case it grows significantly over the forecast period. An incremental (decremental) change of 0.5 percent in gas demand per year from 1996 to 2010 in this sector is used in the sensitivity test runs. The corresponding core industrial demand level increases (decreases) by approximately 116 billion cubic feet in 2000 and 393 billion cubic feet in 2010 relative to the reference case.

Noncore industrial demand In the industrial sector, the noncore market representing about 45 percent of industrial gas demand in 1993 also plays a major role in the natural gas industry because of the off-peak nature of the load. Industrial processes that can switch to alternative fuels choose their fuel based on the availability and cost of competing fuels. An incremental (decremental) change of 0.5 percent in gas demand per year from 1996 to 2010 in this sector is explored. The noncore industrial demand level increases (decreases) by approximately 100 billion cubic feet in 2000 and 320 billion cubic feet in 2010 relative to the reference case.

Compressor station fuel efficiency (shrinkage) Pipeline fuel use is taken into consideration in the establishment of the mass balance constraints at each transshipment node or each storage point of the gas pipeline network. This sensitivity explores a 2 percent per year increase (decrease) in the fuel efficiency parameters. Relative to the reference case, consumption of natural gas by compressor stations in 2010 increases by 328 billion cubic feet in the high case, and decreases by 165 billion cubic feet in the low case.

Weather factor (reserve margin) in the Capacity Expansion Module Capacity expansion and flow constraints for each network interregional arc ensure that pipeline capacity is built to satisfy only firm peak period demand and that the total flows along the interregional arcs are less than or equal to the available capacities. In developing these constraints, it is assumed that local distribution companies reserve approximately 15 percent more pipeline capacity than the level required for a normal winter, to provide reliable service under unusual weather conditions. This sensitivity test explores increasing this reserve margin to 20 percent.

Cost of new capacity exiting the Mountain Region The Mountain region exhibits the largest expansion of pipeline capacity in the reference case. This sensitivity explores the impact of reducing the cost of new pipeline capacity from the Mountain Region to the West North Central Region. The cost change is implemented by reducing the monthly reservation fee associated with new pipeline capacity by $2 per Mcf. This cost change represents an average reduction of 86.8 percent in the tariff associated with the first step of capacity cost curve in the reference case. This sensitivity has an impact only on the amount of capacity the model chooses to build. It does not have an impact on the cost of new capacity used to generate a transportation tariff for use in the Annual Flow Module.

Analysis Approach

This report focuses on the responsiveness in selected output variables due to changes in certain key input variables. The analysis employs one-at-a-time changes in the values of the input variables. This approach meets the principal intent of the Model Developers Report (MDR): to assess the performance characteristics of the NGTDM.

The analysis shows the impact of input variation on the following key output variables:

- Natural gas wellhead price
- Residential natural gas price
- Industrial natural gas price
- Average delivered natural gas price over all sectors
- Total inter-regional pipeline capacity
- Average pipeline capacity utilization rate entering net consuming regions
- Average pipeline capacity utilization rate exiting net producing regions
- Cumulative capital investments for pipeline capacity additions
- Major interstate pipeline annual revenue requirement
- Pipeline fuel consumption
- Carbon emissions from the transmission of natural gas

For the regional sensitivity, Region 3 prices and average prices excluding Region 3 are also presented. Other output variables such as end-use gas markups and other end-use gas prices undoubtedly would be of interest to certain analysts, but the chosen variables were selected because of interest generated by the findings of past model audits and because they have an impact on other models of NEMS.

There are four forms of presenting the model output sensitivities which relate to the variations in the key input variables:

(1) model results in 2000 and 2010
(2) percentage change in results from the reference case value in 2000 and 2010
(3) ratio of percentage change in output to percentage change in input for 2000 and 2010
(4) percentage change in results through time and across related scenarios in the forms of graphs.

The computation of the ratio of percentage change in output to percentage change in input needs to be clarified with regard to how the percentage change in input (the denominator) is derived for the variation in each key input variable. The denominator is calculated differently for changes in gas demands as compared to changes in technical parameters. The denominator used in describing the percentage change in gas demand is calculated as an arithmetic mean of the percentage changes in demand over the years represented. For the case of a change in gas demand of 0.5 percent in 1996, 1 percent in 1997, 1.5 percent in 1998, 2 percent in 1999, and 2.5 percent in 2000, the denominator is 1.5 percent ((0.5 + 1.0 + 1.5 + 2.0 + 2.5)/4). Similarly, covering the period from 1996 to 2010, the denominator is 4 percent. The average percent changes computed here are representative of the true percent changes in gas demand from the model's base year. The actual change from the base year may be different because changes in the reference level of consumption occur throughout the forecast period as show in Figure 1.

For the technical parameters category, the percentage changes for the input variables are provided below.

o Compressor shrinkage

A 2 percent incremental (or decremental) change in compressor station fuel efficiency from 1990 to 2010 results in the following values for the denominator:

- in 2000, -19.93 percent for the low case and 24.34 percent for the high case.
- in 2010, -34.57 percent for the low case and 51.57 percent for the high case.

o Weather factor in the Capacity Expansion Module

A change from 15 percent to 20 percent more pipeline capacity than the level required for a normal winter results in the denominator being 33.33 percent for the high case.

o Cost of new capacity exiting the Mountain Region

A reduction in the monthly reservation fee associated with new pipeline capacity from the Mountain Region to the West North Central Region of $2 per Mcf of interregional capacity results in the denominator being 86.8 percent (($2.30 - $2.00)/$2.30)) for the low case.[7]

[7]The monthly reservation fee in the reference case is $2.30 per Mcf.

IV. Sensitivity Results

Summary of Findings

Wellhead and end-use prices, pipeline capacity, investment levels, and revenue requirements respond positively to changes in demand. The response of these model outputs is generally symmetric and increases over time. The greatest response is observed on the wellhead price. This response is significantly overstated because the test configuration does not provide for feedback from the natural gas supply module. The absolute wellhead price changes are reflected on approximately a one-to-one basis in the end-use price changes. Relative to the wellhead price, the percentage change in the set of end-use prices is less than that in the wellhead price because the wellhead price is just one component of the end-use price.

The model behavior observed in the regional demand sensitivity test is consistent with the national demand sensitivity tests. The regional sensitivity test indicates that the direction of the model's response is the same across the regions. The end-use price response is slightly greater in the one region where demand varies than in the regions of the model where the demand is held constant.

Sensitivity tests on technical input parameters demonstrate that the model behavior is consistent with its design. The amount of new capacity and the revenue required to pay for that capacity increases if the assumed capacity reserve margin is increased. The wellhead price, delivered prices, pipeline fuel use, and emissions respond positively to changes in compressor station shrinkage. Finally, small amounts of incremental pipeline capacity may be built if the cost of constructing pipelines is reduced. However, the test on the arc connecting the Mountain Region to the West North Central Region indicates that this amount is relatively small because the primary drivers behind building new capacity are the scheduled capacity additions and the expected growth in core demand.

Individual Test Results

For presentation purposes, the individual sensitivity tests are presented in two groups. The first group covers the demand sensitivities and the second group covers the sensitivity tests conducted for technical input parameters. At the beginning of each group of tests, the expected model behavior is discussed. This presentation is followed by a discussion of the results for each sensitivity test.

Demand Sensitivities

An increase (decrease) in the consumption of a good with increasing marginal costs should result in an increase (decrease) in the price of the good due to increased (decreased) production. Therefore, an expected result of the demand sensitivities is that prices would increase with higher demand and decrease in response to lower demand. The changes in prices are expected to be larger in the later years of the forecast because this is when the demand change is the greatest and because in the stand-alone configuration the supply curves do not respond to price changes over time.

In addition to the price changes, changes in demand may also lead to changes in the forecast for pipeline capacity and pipeline revenue requirements. As with prices, these model outputs are generally expected to increase (decrease) with an increase (decrease) in demand because pipeline capacity is a factor in satisfying the demand for natural gas. Pipeline capacity changes are not expected to be relatively as great as changes in demand because existing capacity may be under-utilized. An incremental change in residential sector demand is expected to result in an equivalent or larger change in pipeline capacity than the same change in the industrial sector core demand because the residential demand is more seasonal than industrial demand. Similarly, an incremental change in industrial sector core demand is expected to result in an equivalent or larger change in pipeline capacity, than the same change in the industrial sector noncore demand, because the noncore demand is greater during off peak periods.

The revenue requirement is the level of revenue that must be generated if the pipelines are to recover all of their costs associated with providing transportation service. Most of the costs in the revenue requirement are fixed costs; and therefore, within the NGTDM, the costs are related to the capacity of the pipeline. Throughput volumes have little impact on the revenue requirement because variable costs are relatively small. Thus, significant changes in the revenue requirements are not expected unless pipeline capacity changes. When pipeline capacity levels increase (decrease) the revenue requirement is expected to increase (decrease). New capacity generally costs more than existing capacity, therefore, the percentage change in the revenue requirement is expected to be greater than the percentage change in the incremental capacity. Additionally, the incremental revenue requirement should at a minimum cover the incremental return, income taxes, and depreciation expense.

National Residential Demand Sensitivity

As presented in Tables 1A, 1B, and 1C, the results from the national residential demand sensitivity test are consistent with the general expectations for the demand sensitivities outlined above. The cases with 2.5 percent higher and 2.5 percent lower residential demand in 2000 did not result in the need for any more or less pipeline capacity than in the reference case, respectively. This is consistent with residential gas use peaking at 5.15 trillion cubic feet in 1994 and declining to 5.00 trillion cubic feet in 2000 in the reference scenario. Prior to 2000, pipeline capacity additions are primarily determined by scheduled projects and, to a lesser degree, demand expectations in other sectors. Consistent with the lack of difference in inter-regional pipeline capacity, pipeline capital investment and the revenue requirements were the same across cases in 2000.

In the 2001 to 2010 time period, demand changes had to be significantly large to alter inter-regional pipeline capacity requirements. As expected, increased (decreased) demand resulted in increases (decreases) in capacity requirements, in the capital investment for pipeline capacity, and in the annual revenue requirement. The increase and decrease in the revenue requirement is consistent with a $21

Table 1.A Sensitivity Analysis: Variation in Residential Demand Model Results

		2000			2010		
INPUT VARIABLE	**Units**	**Low Case**	**Reference case**	**High Case**	**Low Case**	**Reference Case**	**High Case**
Residential Demand	TCF	4.870	4.995	5.120	4.531	4.898	5.265
OUTPUT VARIABLE							
Gas Wellhead Price	1993$/ MCF	2.24	2.33	2.41	2.87	3.49	4.14
Residential Gas Price	1993$/ MCF	6.19	6.27	6.34	6.62	7.22	7.87
Industrial Gas Price	1993$/ MCF	3.16	3.24	3.32	3.76	4.38	5.05
Total Inter-regional Pipeline Capacity	BCF per Year	43,250	43,250	43,250	45,436	45,713	45,978
Cumulative Capital Investment for Pipeline Capacity Additions	Millions of 1993 $	15,797	15,797	15,797	20,105	20,634	21,151
Major Interstate Pipeline Annual Revenue Requirement	Millions of 1993 $	7,408	7,408	7,408	6,923	7,021	7,116

Table 1.B	**Sensitivity Analysis: Variation in Residential Demand Percentage Changes from Reference Case**			
	2000		**2010**	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	-3.69	3.28	-17.62	18.63
Residential Gas Price	-1.32	1.14	-8.34	9.04
Industrial Gas Price	-2.67	2.35	-14.15	15.19
Total Inter-regional Pipeline Capacity	0.00	0.00	-0.60	0.58
Cumulative Capital Investment for Pipeline Capacity Additions	0.00	0.00	-2.56	2.50
Major Interstate Pipeline Annual Revenue Requirement	0.00	0.00	-1.39	1.35

Table 1.C	**Sensitivity Analysis: Variation in Residential Demand Ratio of Percentage Change in Output to Percentage Change in Input**			
	2000		**2010**	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	2.46	2.18	4.40	4.66
Residential Gas Price	0.88	0.76	2.08	2.26
Industrial Gas Price	1.78	1.57	3.54	3.80
Total Inter-regional Pipeline Capacity	0.00	0.00	0.15	0.15
Cumulative Capital Investment for Pipeline Capacity Additions	0.00	0.00	0.64	0.63
Major Interstate Pipeline Annual Revenue Requirement	0.00	0.00	0.35	0.34

million 1993 dollar estimate of additional revenue required to cover the first full year of fixed costs associated with a capital investment of $100 million 1993 dollars.[8]

Across the high and low demand sensitivities, the industrial and residential natural gas prices show a very similar response. End-use prices in both sectors reflect the change in the wellhead price. The transmission and distribution (T&D) markup does not change significantly because, even absent the change in demand, the incremental revenue requirement increases the average T&D markup by less than $0.01 per thousand cubic feet.

The price response in the low and high demand sensitivity tests is largely symmetric about the reference price path. In 2010, the changes are slightly larger in the high case than in the low case. This difference is largely a result of the functional form of the supply curve. The supply curve has a small area around the reference price and quantity where the slope of the curve is very small. To the right of this base step (higher supply levels), the slope of the curve increases significantly while moving to the left of this base step (lower supply levels) the slope also increases but to a lesser degree than the slope at the higher supply levels. In summary, a greater price increase will be observed in increasing supplies than the price decrease that will be observed for the same incremental drop in production levels.

East North Central Residential Demand Sensitivity

Approximately 30 percent of the 1993 residential natural gas consumption in the U.S. was consumed in the East North Central Census Division (Region 3). In the reference scenario, the regional share of residential natural gas consumption remains at 30 percent in 2000 and 2010. To address concerns about regional price behavior, the regional demand sensitivity tests were performed by applying the same specifications used in the national residential demand sensitivity test to demand levels in only this region. The results of these sensitivity tests are presented in Tables 2A, 2B, and 2C. Similar to the results of all the other sensitivity tests, the results from this regional sensitivity test are consistent with the general expectations for the demand sensitivities outlined above. In this case the expectations were met for the regional values as well as for the national values.

Price changes in the regional test are significantly less than in the national residential demand sensitivity test because the demand changes are significantly less. In fact, the difference in the magnitude of the price changes is approximately proportional to the percentage difference in demand between the two tests.

The most interesting observation about the regional demand sensitivity test is that the price impacts are slightly greater for the delivered prices within the region, compared to the price impacts outside of the region (see Figures 4 and 5 in Appendix A). Although the difference in the price change is small, it is consistent with aligning cost responsibility with cost causation. This same pattern is observed in comparing price changes for residential and nonresidential end-use prices within the region. Within the region, the price response to the nonresidential sectors is less than the price response in the residential sector because the nonresidential consumption includes a significant level of noncore consumption that sees little if any price change.

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[8] This estimate is based on a 50 percent debt and 50 percent common equity capital structure and an assumed weighted average cost of capital of 10 percent, an income tax rate of 35 percent, and a 30 year straight-line depreciation schedule. Costs in latter years of the life of the asset are likely to be lower as the plant becomes more depreciated.

Table 2.A Sensitivity Analysis: Variation in Residential Demand in Region 3 Model Results							
		2000			2010		
INPUT VARIABLE	**Units**	**Low Case**	**Reference Case**	**High Case**	**Low Case**	**Reference Case**	**High Case**
Region 3 Residential Demand	TCF	1.485	1.523	1.561	1.337	1.445	1.553
OUTPUT VARIABLE							
Gas Wellhead Price	93$/MCF	2.30	2.33	2.36	3.27	3.49	3.71
Total Inter-region Pipeline Capacity	BCF/yr	43,249	43,249	43,249	45,583	45,712	45,833
Cumulative Capital Investment for Pipeline Capacity Additions	Millions 93$	15,796	15,796	15,796	20,389	20,634	20,862
Major Interstate Pipeline Annual Revenue Requirement	Millions 93$	7,407	7,407	7,407	6,975	7,021	7,061
Avg. Residential Gas Price	93$/MCF	6.24	6.27	6.29	7.03	7.22	7.43
Avg. Non-Residential Gas Price	93$/MCF	3.56	3.59	3.61	4.51	4.71	4.94
Reg. 3 Avg. Residential Gas Price	93$/MCF	5.62	5.66	5.69	6.42	6.68	6.92
Reg. 3 Avg. Non-Residential Gas Price	93$/MCF	3.77	3.81	3.83	4.55	4.80	5.04
Non-region 3 Avg. Residential Gas Price	93$/MCF	6.50	6.54	6.56	7.27	7.45	7.66
Non-region 3 Avg. Non-Residential Gas Price	93$/MCF	3.52	3.55	3.57	4.51	4.69	4.92

Table 2.B Sensitivity Analysis: Variation in Residential Demand in Region 3 Percentage Changes from Reference Case				
	2000		2010	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	-1.47	1.24	-6.17	6.46
Total Inter-region Pipeline Capacity	0.00	0.00	-0.28	0.26
Cumulative Capital Investment for Pipeline Capacity Additions	0.00	0.00	-1.19	1.10
Major Interstate Pipeline Annual Revenue Requirement	0.00	0.00	-0.64	0.58
Avg. Residential Gas Price	-0.48	0.32	-2.63	2.91
Avg. Non-Residential Gas Price	-0.84	0.56	-4.25	4.88
Reg. 3 Avg. Residential Gas Price	-0.71	0.53	-3.89	3.59
Reg. 3 Avg. Non-Residential Gas Price	-1.05	0.52	-5.21	5.00
Non-region 3 Avg. Residential Gas Price	-0.61	0.31	-2.42	2.82
Non-region 3 Avg. Non-Residential Gas Price	-0.85	0.56	-3.84	4.90

Table 2.C	**Sensitivity Analysis: Variation in Residential Demand in Region 3 Ratio of Percentage Change in Output to Percentage Change in Input**			
	2000		**2010**	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	0.98	0.83	1.54	1.61
Total Inter-region Pipeline Capacity	0.00	0.00	0.07	0.07
Cumulative Capital Investment for Pipeline Capacity Additions	0.00	0.00	0.30	0.28
Major Interstate Pipeline Annual Revenue Requirement	0.00	0.00	0.16	0.14
Avg. Residential Gas Price	0.32	0.21	0.66	0.73
Avg. Non-Residential Gas Price	0.56	0.37	1.06	1.22
Reg. 3 Avg. Residential Gas Price	0.47	0.35	0.97	0.90
Reg. 3 Avg. Non-Residential Gas Price	0.70	0.35	1.30	1.25
Non-region 3 Avg. Residential Gas Price	0.41	0.20	0.60	0.70
Non-region 3 Avg. Non-Residential Gas Price	0.56	0.38	0.96	1.23

Core Industrial Demand Sensitivity

As presented in Tables 3A, 3B, and 3C, the results from the national industrial core demand sensitivity tests are consistent with the general expectations for the demand sensitivities outlined above. Additionally, the patterns in the model output are very similar to the national residential demand sensitivity. The cases with 2.5 percent higher and 2.5 percent lower industrial demand in 2000 did not result in the need for any more or less pipeline capacity than in the reference case, respectively. This is consistent with the very small growth in core industrial gas demand from 1994 to 2000. Consistent with the lack of difference in inter-regional pipeline capacity, pipeline capital investment and the revenue requirements were unchanged in 2000.

In the 2001 to 2010 time period, demand changes had to be significantly large to alter inter-regional pipeline capacity requirements. Following the increase (decrease) in capacity requirements is the increase (decrease) in the capital investment for pipeline capacity and the annual revenue requirement. Similar to the residential demand sensitivity, the increase (decrease) in the revenue requirement is consistent with an estimate of $21 million dollars of additional revenue required to cover the first full year of fixed costs associated with a $100 million dollar capital investment.

Across the high and low demand sensitivities, the industrial and residential natural gas prices show a very similar response. End-use prices in both sectors reflect the change in the wellhead price. In 2010, the transmission and distribution (T&D) markup to the industrial sector changes slightly more than in the residential sector. This change is most likely attributable to a small increase in the noncore industrial markup. The noncore industrial markup increase reflects a reduction in the pipeline capacity available to the noncore market.

Despite the absolute change in the 2010 demand being greater for the industrial core demand sensitivity, the changes in the pipeline capacity, capital investment, and pipeline revenue requirement are less than that observed in the residential demand sensitivity cases. The lower sensitivity to the industrial core demand is attributable to the more levelized load of the industrial sector consumption throughout the year and the close proximity of industrial demand to major sources of supply.

A comparison of the model's performance over time across the three core demand sensitivity tests is presented in Figures 2 - 7 in Appendix A. The graphics show that for wellhead (Figure 2) and end-use prices (Figure 3) the national residential and industrial sensitivity test yield very similar results. This behavior is consistent with the similarity in the change in demand for these two tests. The variation in pipeline capacity and revenue requirements between these tests is much larger than the variation in the demand inputs. The greater sensitivity to the residential demand is attributed to the more seasonal nature of the residential load and the greater distance between the residential load and the supply areas relative to the industrial load.

Table 3.A Sensitivity Analysis: Variation in Core Industrial Demand Model Results

		2000			2010		
INPUT VARIABLE	**Units**	**Low Case**	**Reference Case**	**High Case**	**Low Case**	**Reference Case**	**High Case**
Core Industrial Demand	TCF	4.520	4.636	4.752	4.844	5.237	5.630
OUTPUT VARIABLE							
Gas Wellhead Price	1993$/ MCF	2.24	2.33	2.40	2.87	3.49	4.16
Residential Gas Price	1993$/ MCF	6.18	6.27	6.33	6.63	7.22	7.90
Industrial Gas Price	1993$/ MCF	3.14	3.24	3.32	3.74	4.38	5.08
Total Inter-regional Pipeline Capacity	BCF per Year	43,250	43,250	43,250	45,510	45,713	45,903
Cumulative Capital Investment for Pipeline Capacity Additions	Millions of 1993 $	15,797	15,797	15,797	20,236	20,634	21,007
Major Interstate Pipeline Annual Revenue Requirement	Millions of 1993 $	7,408	7,408	7,408	6,947	7,021	7,088

Table 3.B	**Sensitivity Analysis: Variation in Core Industrial Demand Percentage Changes from Reference Case**			
	2000		**2010**	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	-4.01	2.97	-17.79	19.29
Residential Gas Price	-1.48	0.98	-8.22	9.36
Industrial Gas Price	-3.12	2.26	-14.60	15.84
Total Inter-regional Pipeline Capacity	0.00	0.00	-0.44	0.42
Cumulative Capital Investment for Pipeline Capacity Additions	0.00	0.00	-1.93	1.81
Major Interstate Pipeline Annual Revenue Requirement	0.00	0.00	-1.05	0.96

Table 3.C	**Sensitivity Analysis: Variation in Core Industrial Demand Ratio of Percentage Change in Output to Percentage Change in Input**			
	2000		**2010**	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	2.67	1.98	4.45	4.82
Residential Gas Price	0.98	0.65	2.06	2.34
Industrial Gas Price	2.08	1.51	3.65	3.96
Total Inter-regional Pipeline Capacity	0.00	0.00	0.11	0.10
Cumulative Capital Investment for Pipeline Capacity Additions	0.00	0.00	0.48	0.45
Major Interstate Pipeline Annual Revenue Requirement	0.00	0.00	0.26	0.24

Noncore Industrial Demand Sensitivity

The results of the noncore industrial demand sensitivity indicate that of the three demand sensitivity tests, the output variables are least sensitive to the change in noncore industrial demand. The results of the test are presented in Tables 4A, 4B, and 4C. The outputs presented in these tables follow the expectations for the demand sensitivities outlined above. The changes in prices, pipeline capacity, capital investment, and pipeline revenue requirement are less than those observed in the industrial core demand sensitivity. The lower sensitivity to the industrial noncore demand is attributable to the off-peak nature of the load and the closer proximity of industrial demand to major sources of supply.

In the 2001 to 2010 time period, demand changes had to be significantly large to alter inter-regional pipeline capacity requirements. The sensitivity of pipeline capacity to noncore industrial demand was not anticipated because the Capacity Expansion Module of the NGTDM is specifically designed to build new capacity for the needs of only the core markets. Small changes in pipeline capacity additions may be attributable to shifts in flow patterns in the low and high cases. This particular issue requires further investigation and may lead to a change in the model specification.

Table 4.A Sensitivity Analysis: Variation in Noncore Industrial Demand Model Results

		2000			2010		
INPUT VARIABLE	**Units**	**Low Case**	**Reference Case**	**High Case**	**Low Case**	**Reference Case**	**High Case**
Noncore Industrial Demand	TCF	3.924	4.025	4.126	3.983	4.306	4.629
OUTPUT VARIABLE							
Gas Wellhead Price	1993$/ MCF	2.26	2.33	2.39	2.98	3.49	4.07
Residential Gas Price	1993$/ MCF	6.20	6.27	6.32	6.72	7.22	7.82
Industrial Gas Price	1993$/ MCF	3.18	3.24	3.29	3.87	4.38	4.96
Total Inter-regional Pipeline Capacity	BCF per Year	43,250	43,250	43,250	45,602	45,713	45,818
Cumulative Capital Investment for Pipeline Capacity Additions	Millions of 1993 $	15,797	15,797	15,797	20,425	20,634	20,833
Major Interstate Pipeline Annual Revenue Requirement	Millions of 1993 $	7,408	7,408	7,408	6,983	7,021	7,057

Table 4.B Sensitivity Analysis: Variation in Noncore Industrial Demand Percentage Changes from Reference Case				
	2000		2010	
OUTPUT VARIABLE	Low Case	High Case	Low Case	High Case
Gas Wellhead Price	-2.91	2.37	-14.46	16.84
Residential Gas Price	-1.19	0.73	-6.91	8.35
Industrial Gas Price	-2.08	1.57	-11.66	13.25
Total Inter-regional Pipeline Capacity	0.00	0.00	-0.24	0.23
Cumulative Capital Investment for Pipeline Capacity Additions	0.00	0.00	-1.01	0.96
Major Interstate Pipeline Annual Revenue Requirement	0.00	0.00	-0.55	0.51

Table 4.C Sensitivity Analysis: Variation in Noncore Industrial Demand Ratio of Percentage Change in Output to Percentage Change in Input				
	2000		2010	
OUTPUT VARIABLE	Low Case	High Case	Low Case	High Case
Gas Wellhead Price	1.94	1.58	3.62	4.21
Residential Gas Price	0.79	0.49	1.73	2.09
Industrial Gas Price	1.39	1.04	2.91	3.31
Total Inter-regional Pipeline Capacity	0.00	0.00	0.06	0.06
Cumulative Capital Investment for Pipeline Capacity Additions	0.00	0.00	0.25	0.24
Major Interstate Pipeline Annual Revenue Requirement	0.00	0.00	0.14	0.13

Technical Parameter Sensitivities

The technical parameter sensitivity tests were designed to verify that the model response to selected model inputs is consistent with the model design. Inputs relating to investment in pipeline capacity and emission levels were chosen because (1) these outputs are new in NEMS, (2) they have important implications for other modules of NEMS, and (3) they are useful for relevant policy analysis.

Increasing the pipeline compressor station shrinkage is the equivalent of increasing the demand for natural gas by increasing pipeline fuel consumption. Therefore, similar to the demand sensitivities, an increase (decrease) in the pipeline compressor shrinkage should result in an increase (decrease) in the price of natural gas. The change in price is expected to be larger in the later years of the forecast when the shrinkage change has the greatest impact on pipeline fuel consumption.

In addition to the impact on prices, compressor station shrinkage is of interest because it is a principal determinate of carbon emissions. The model uses a linear function to estimate carbon emissions from compressor station fuel usage. Therefore, it is expected that the percent change and the elasticity for pipeline fuel consumption will be the same as the percent change and the elasticity for emissions.

Two tests were designed to test the sensitivity of inter-regional pipeline capacity to the "weather factor" and to the cost of the new capacity. Only a high case was conducted for the weather factor, because reducing the weather factor from the base level could force the model solution algorithm into an infeasible decision space. Only a low pipeline capacity price case was conducted because in the reference case, no unscheduled capacity was constructed along the arc linking the Mountain Region to the West North Central Region. Increasing the cost of new capacity along this arc would result in the model essentially replicating the outputs of the reference scenario.

The weather factor and the capacity cost sensitivities may result in changes in pipeline capacity additions. Similar to the demand sensitivities, changes in pipeline capacity should induce a change in the level of investment in new pipeline capacity and the level of the annual revenue requirement. Revenue requirements are generally expected to increase (decrease) with an increase (decrease) in pipeline capacity because they reflect the cost of this capacity. Additionally, given no change in demand, pipeline capacity utilization is expected to change inversely with inter-regional pipeline capacity. Thus, with a higher weather factor, inter-regional pipeline capacity, pipeline investment, and revenue requirements are expected to be higher while capacity utilization is expected to be lower. The same behavior is expected when the cost of new capacity is reduced because additional capacity is built while total throughput remains unchanged.

Pipeline Shrinkage Sensitivity

The model outputs, percentage change in outputs, and the elasticities for the pipeline shrinkage sensitivity tests are reported in Tables 5A, 5B, and 5C, respectively. The behavior of the outputs is completely consistent with the expected behavior outlined above. Consistent with the linear relationship between pipeline fuel consumption and emissions levels, the percentage change for these two outputs are the same in both 2000 and 2010. The asymmetry in the low and high case relative to the reference case is attributable to the implementation of the scenario, i.e., the 2 percent growth (decline) rate is compounded each year and therefore is applied to a larger (smaller) shrinkage parameter each year of the forecast period.

The annual variation in pipeline fuel consumption and in carbon emissions associated with this consumption is presented in Figures 8 and 9 in Appendix A. The large change in consumption and emissions in 1994 is attributed to the scenario specification and the historical overwrite feature of the model. The change in pipeline shrinkage is initiated in 1990 is applied to the shrinkage parameters each year thereafter. The change in fuel consumption and emissions does not show up in the graphics prior to 1994 because the model reports out historical values for 1990 through 1993.

Table 5.A Sensitivity Analysis: Variation in Compressor Shrinkage Model Results

		2000			2010		
OUTPUT VARIABLE	**Units**	**Low Case**	**Reference Case**	**High Case**	**Low Case**	**Reference Case**	**High Case**
Gas Wellhead Price	1993$/ MCF	2.24	2.33	2.45	3.14	3.49	4.08
Average Delivered Gas Price	1993$/ MCF	4.15	4.25	4.36	4.89	5.25	5.91
Pipeline Fuel Consumption	TCF/yr	0.51	0.64	0.81	0.41	0.63	0.95
Carbon Emissions	Million Metric Tons	7.64	9.53	11.98	6.04	9.29	14.16

Table 5.B	**Sensitivity Analysis: Variation in Compressor Shrinkage Percentage Changes from Reference Case**			
	2000		**2010**	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	-4.01	4.98	-9.88	16.90
Average Delivered Gas Price	-2.33	2.52	-6.87	12.57
Pipeline Fuel Consumption	-19.87	25.69	-35.00	52.48
Carbon Emissions	-19.87	25.69	-35.00	52.48

Table 5.C	**Sensitivity Analysis: Variation in Compressor Shrinkage Ratio of Percentage Change in Output to Percentage Change in Input**			
	2000		**2010**	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	0.20	0.20	0.29	0.33
Average Delivered Gas Price	0.12	0.10	0.20	0.24
Pipeline Fuel Consumption	1.00	1.06	1.01	1.02
Carbon Emissions	1.00	1.06	1.01	1.02

Weather Factor Sensitivity

As reported in Table 6A, the weather factor sensitivity test resulted in a significant increase in the amount of new pipeline capacity added in the first few years of the forecast period. In 2000, the inter-regional pipeline capacity is approximately 6 percent greater than in the reference case (Table 6B). The incremental pipeline capacity additions cause a 41 percent increase in the level of investment in pipeline capacity in 2000. Consistent with the change in investment is a change in the revenue requirement. The impact of the change in the weather factor is reduced over time because most of the incremental capacity is driven by the need to increase the "reserve margin" for existing interstate pipeline capacity. Most of this incremental capacity is built the first year the Capacity Expansion Model is able to add capacity. In the 2001 to 2010 time period, the change in the weather factor has the effect of increasing the amount of new capacity by approximately 6 percent. This change in capacity additions is consistent with the level of change in the weather factor.

The increase in the amount of pipeline capacity results in a decrease in the level of pipeline capacity utilization. Pipeline capacity utilization changes are the greatest for pipeline capacity entering net consuming regions while the pipeline capacity utilization changes are quite small for net producing regions. This observation is consistent with the capacity entering net consuming regions being primarily driven by peak period requirements (which are a function of the weather factor) while capacity exiting producing areas being primarily driven by annual throughput requirements. Apparently a significant amount of surplus capacity exiting the supply regions is available as shown by the 20 percent decline in capacity utilization exiting the net producing regions from 2000 to 2010 in the reference case.

The increase in pipeline capacity also has an impact on the wellhead and end-use prices. The additional capacity provides greater access to less expensive sources of supply and results in a $0.04 and $0.06 per thousand cubic feet reduction in the average wellhead price in 2000 and 2010, respectively. The benefits of the reduced wellhead price are somewhat mitigated by increases in the transmission and distribution (T&D) margins. In 2010, full recovery of the incremental revenue requirement requires an increase of $0.035 per thousand cubic feet in the average T&D margin. The net reduction in the 2010 average end-use price of $0.03 per thousand cubic feet reflects full cost recovery of the increment revenue requirement. In contrast, full recovery of the incremental revenue requirement is not reflected in the 2000 end-use price. The lack of full cost recovery in 2000 is most likely related to the way in which the Pipeline Tariff Module uses expectations of throughput volumes to compute pipeline tariffs. This algorithm will be reviewed for potential improvements.

Table 6.A Sensitivity Analysis: Variation in Weather Factor in the Capacity Expansion Module Model Results

		2000			2010		
OUTPUT VARIABLE	**Units**	**Low Case**	**Reference Case**	**High Case**	**Low Case**	**Reference Case**	**High Case**
Gas Wellhead Price	1993$/ MCF	NA	2.33	2.29	NA	3.49	3.43
Average Delivered Gas Price	1993$/ MCF	NA	4.25	4.22	NA	5.25	5.22
Total Inter-regional Pipeline Capacity	BCF per Year	NA	43,250	45,884	NA	45,713	48,587
Average Capacity Utilization Rate entering a net consuming region	Fraction	NA	0.58	0.51	NA	0.63	0.56
Average Capacity Utilization Rate exiting a net producing region	Fraction	NA	0.54	0.53	NA	0.44	0.44
Cumulative Capital Investment for Pipeline Capacity Additions	Millions of 1993 $	NA	15,797	22,274	NA	20,634	27,762
Major Interstate Pipeline Annual Revenue Requirement	Millions of 1993 $	NA	7,408	8,468	NA	7,021	7,814

Table 6.B Sensitivity Analysis: Variation in Weather Factor in the Capacity Expansion Module
Percentage Changes from Reference Case

	2000		2010	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	NA	-1.91	NA	-1.75
Average Delivered Gas Price	NA	-0.61	NA	-0.65
Total Inter-regional Pipeline Capacity	NA	6.09	NA	6.29
Average Capacity Utilization Rate entering a net consuming region	NA	-11.26	NA	-11.42
Average Capacity Utilization Rate exiting a net producing region	NA	-1.88	NA	-1.16
Cumulative Capital Investment for Pipeline Capacity Additions	NA	41.00	NA	34.54
Major Interstate Pipeline Annual Revenue Requirement	NA	14.32	NA	11.30

Table 6.C Sensitivity Analysis: Variation in Weather Factor in the Capacity Expansion Module
Ratio of Percentage Change in Output to Percentage Change in Input

	2000		2010	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	NA	-0.06	NA	-0.05
Average Delivered Gas Price	NA	-0.02	NA	-0.02
Total Inter-regional Pipeline Capacity	NA	0.18	NA	0.19
Average Capacity Utilization Rate entering a net consuming region	NA	-0.34	NA	-0.34
Average Capacity Utilization Rate exiting a net producing region	NA	-0.06	NA	-0.03
Cumulative Capital Investment for Pipeline Capacity Additions	NA	1.23	NA	1.04
Major Interstate Pipeline Annual Revenue Requirement	NA	0.43	NA	0.34

Cost of Region 8 to Region 4 Pipeline Capacity Expansion

Reducing the costs of inter-regional pipeline capacity between the Mountain Region and the West North Central Region in the Capacity Expansion Module resulted in a small increase in inter-regional pipeline capacity as reported in Tables 7A, 7B, and 7C. The results of this sensitivity need to be evaluated in the context that costs in the Annual Flow Module only change to the extent that the CEM provides additional capacity to the AFM. Unlike in the weather factor sensitivity test, the increase in the availability of capacity did not result in a change in the average wellhead price. The wellhead price did not change because the change in the capacity did not change the marginal suppliers of natural gas derived in the market equilibrium process.

Although wellhead prices did not change relative to the reference case, end-use prices increased. The increase in end-use prices reflects recovery of the costs associated with the increase in capacity as reflected in the revenue requirement.

The increase in pipeline capacity without any change in pipeline throughput results in a decline in pipeline capacity utilization. The change in utilization is only observed in the utilization of capacity exiting net producing regions because the Mountain Region is a net producing region.

Table 7.A Sensitivity Analysis: Variation in Cost of New Capacity Exiting the Mountain Region Model Result

		2000			2010		
OUTPUT VARIABLE	**Units**	**Low Case**	**Reference Case**	**High Case**	**Low Case**	**Reference Case**	**High Case**
Gas Wellhead Price	1993$/ MCF	2.33	2.33	NA	3.49	3.49	NA
Average Delivered Gas Price	1993$/ MCF	4.27	4.25	NA	5.28	5.25	NA
Total Inter-regional Pipeline Capacity	BCF per Year	43,953	43,250	NA	46,417	45,713	NA
Average Capacity Utilization Rate entering a net consuming region	Fraction	0.58	0.58	NA	0.63	0.63	NA
Average Capacity Utilization Rate exiting a net producing region	Fraction	0.51	0.54	NA	0.40	0.44	NA
Cumulative Capital Investment for Pipeline Capacity Additions	Millions of 1993 $	18,593	15,797	NA	23,627	20,634	NA
Major Interstate Pipeline Annual Revenue Requirement	Millions of 1993 $	7,933	7,408	NA	7,370	7,021	NA

Table 7.B Sensitivity Analysis: Variation in Cost of New Capacity Exiting the Mountain Region
Percentage Changes from Reference Case

	2000		2010	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	-0.11	NA	0.11	NA
Average Delivered Gas Price	0.47	NA	0.44	NA
Total Inter-regional Pipeline Capacity	1.63	NA	1.54	NA
Average Capacity Utilization Rate entering a net consuming region	0.22	NA	0.10	NA
Average Capacity Utilization Rate exiting a net producing region	-5.15	NA	-8.66	NA
Cumulative Capital Investment for Pipeline Capacity Additions	17.70	NA	14.51	NA
Major Interstate Pipeline Annual Revenue Requirement	7.09	NA	4.97	NA

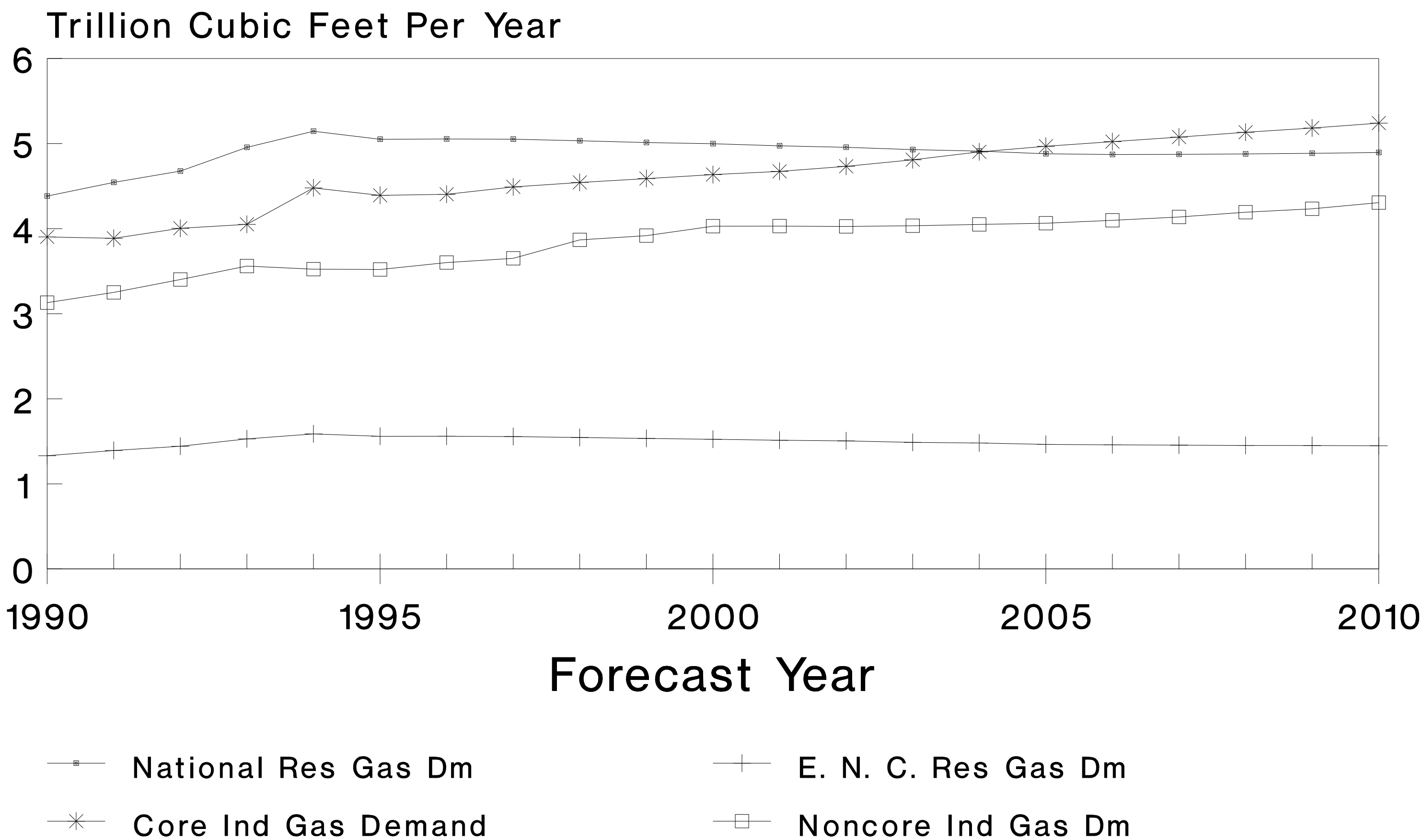
Table 7.C Sensitivity Analysis: Variation in Cost of New Capacity Exiting the Mountain Region
Ratio of Percentage Change in Output to Percentage Change in Input

	2000		2010	
OUTPUT VARIABLE	**Low Case**	**High Case**	**Low Case**	**High Case**
Gas Wellhead Price	0.00	NA	0.00	NA
Average Delivered Gas Price	-0.01	NA	-0.01	NA
Total Inter-regional Pipeline Capacity	-0.04	NA	-0.03	NA
Average Capacity Utilization Rate entering a net consuming region	-0.01	NA	0.00	NA
Average Capacity Utilization Rate exiting a net producing region	0.12	NA	0.20	NA
Cumulative Capital Investment for Pipeline Capacity Additions	-0.40	NA	-0.33	NA
Major Interstate Pipeline Annual Revenue Requirement	-0.16	NA	-0.11	NA

Appendix A

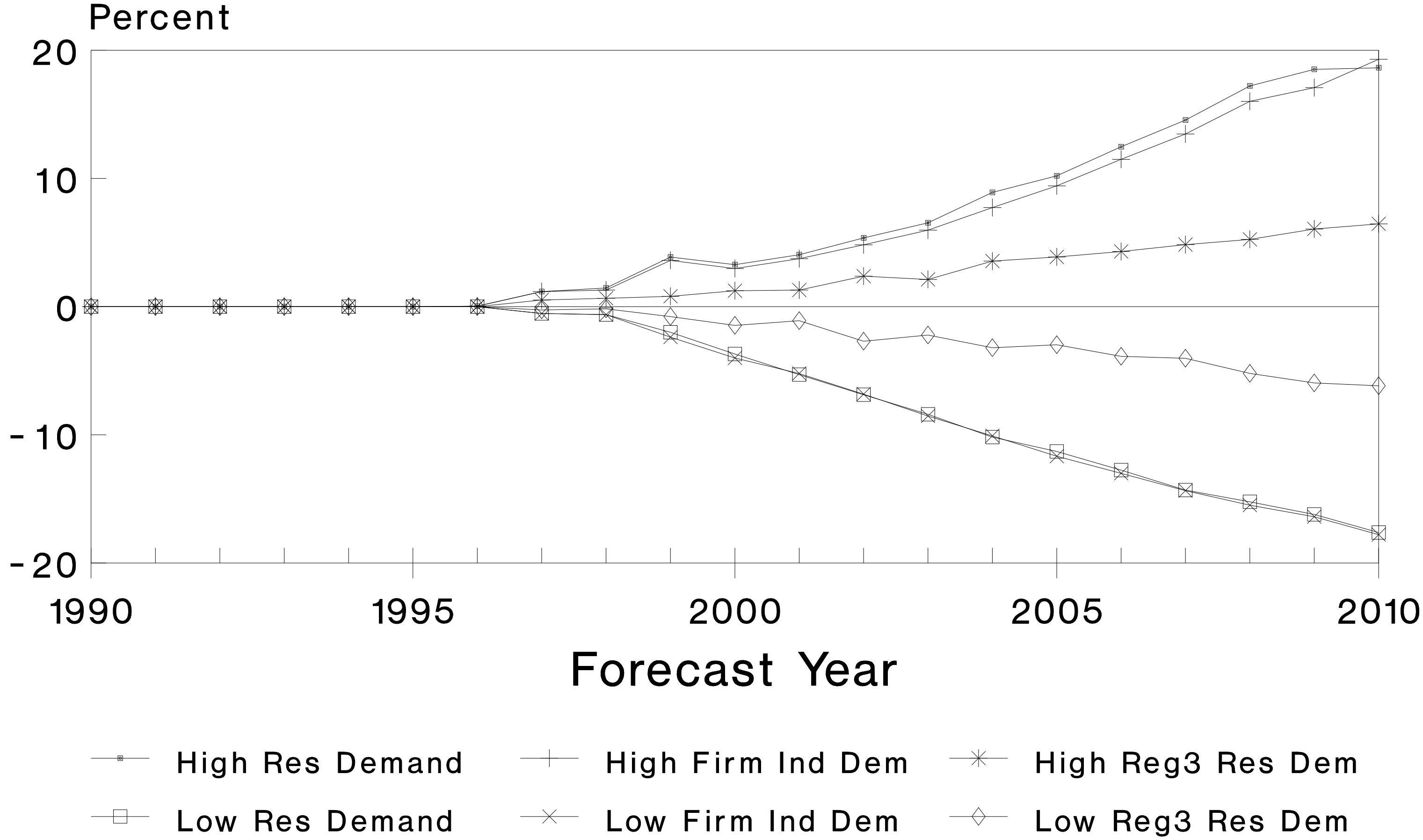
Graphical Presentation of Sensitivity Results

Fig.1. Selected Reference Gas Demand Levels



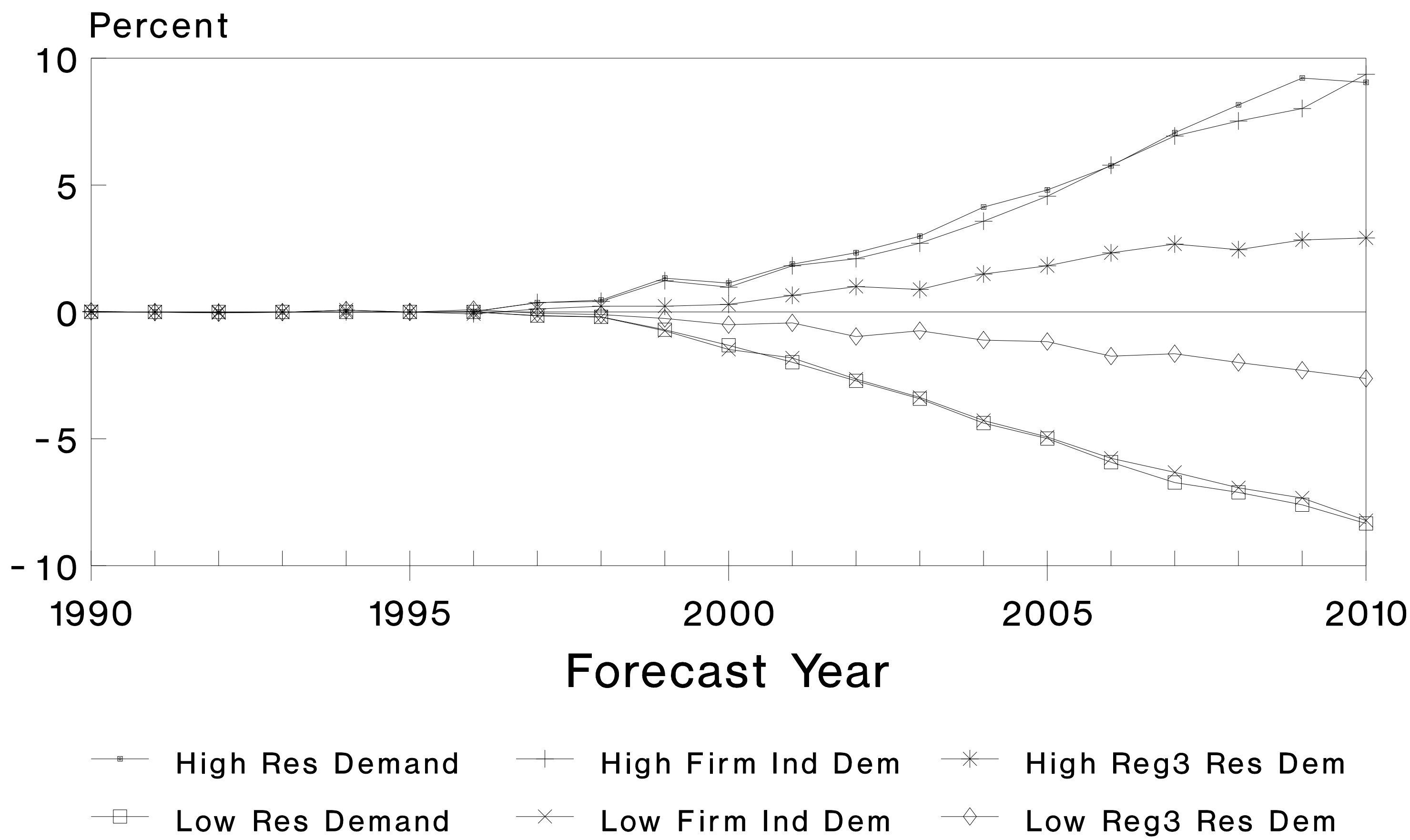
Reference Case Run NGTDM2.D1014941

Fig.2. Variation in Natural Gas Wellhead Price



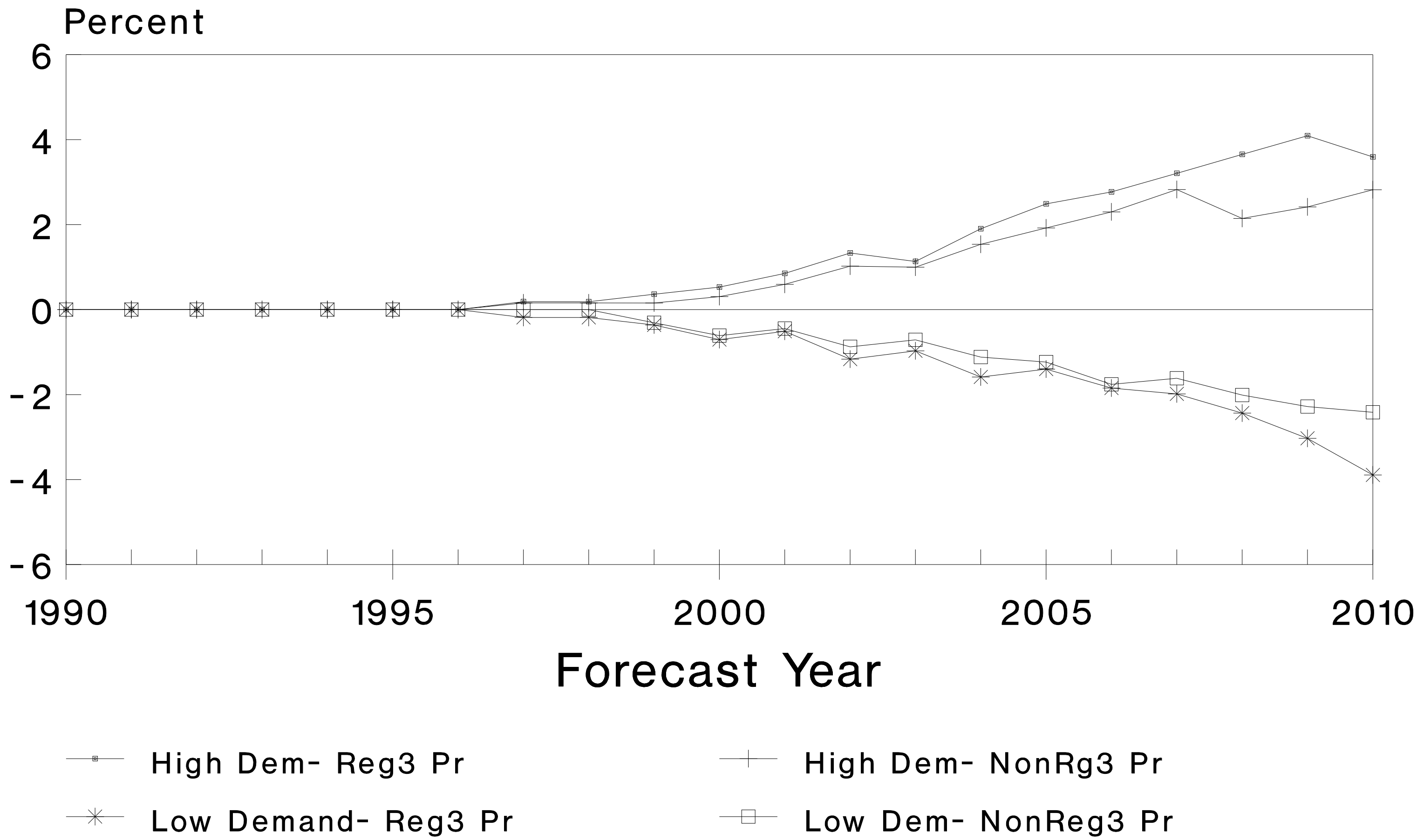
Variation relative to NGTDM2.D1014941

Fig.3. Variation in Residential Gas Price



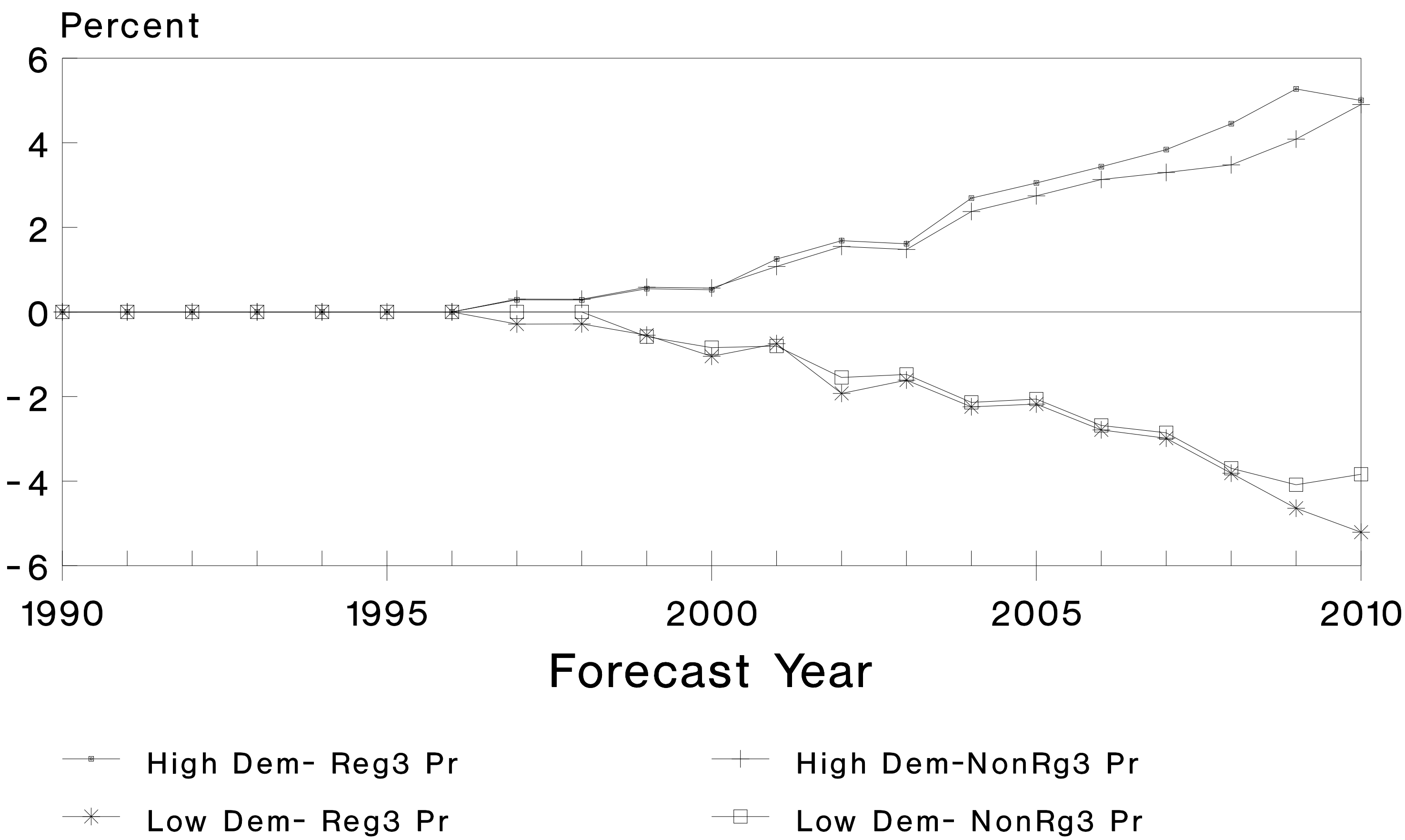
Variation relative to NGTDM2.D1014941

Fig.4. Variation in Residential Prices in Response to Changes in Reg3 Res Dem



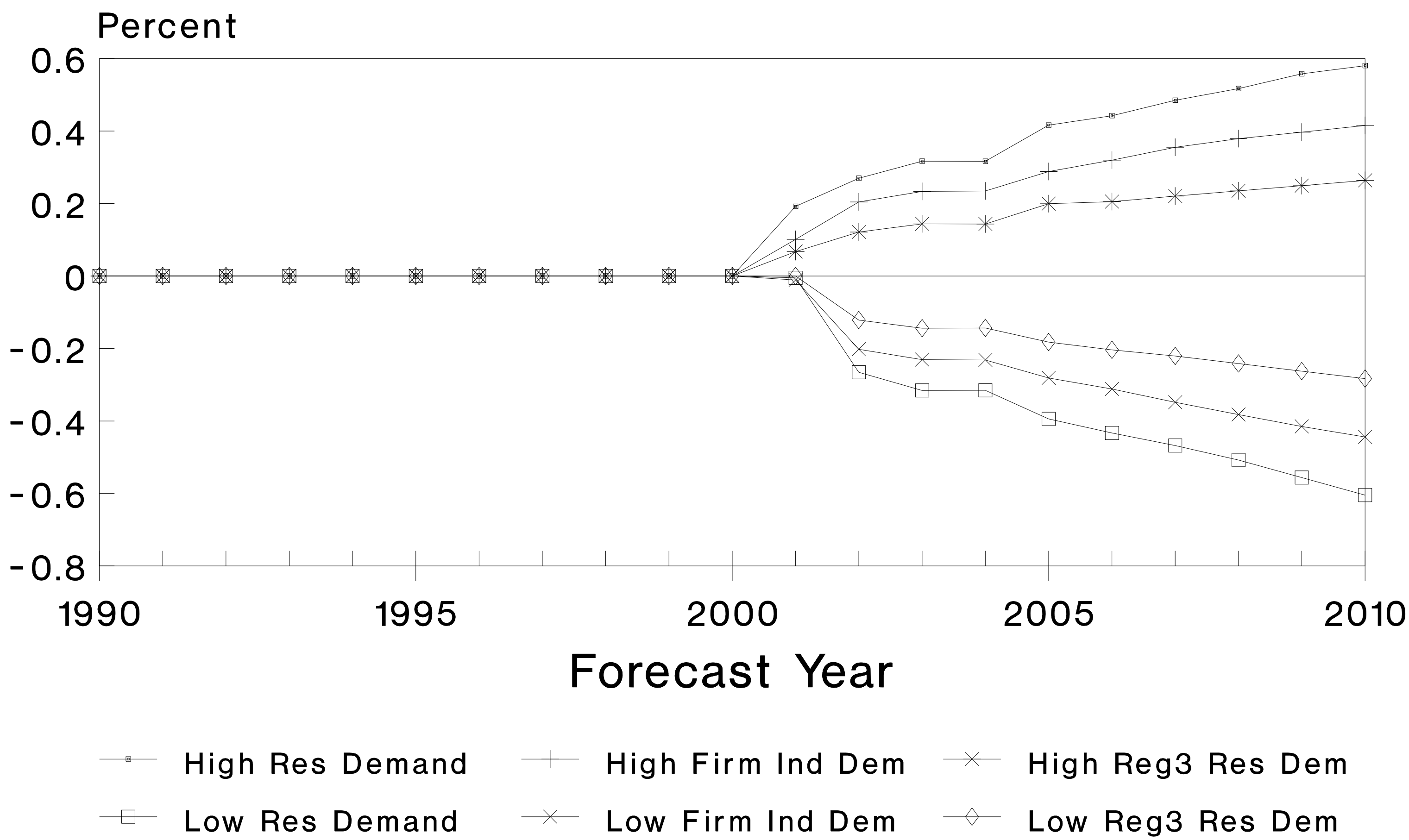
Variation relative to NGTDM2.D1014941

Fig.5. Variation in Non-Res. Gas Prices in Response to Changes in Reg3 Res Dem



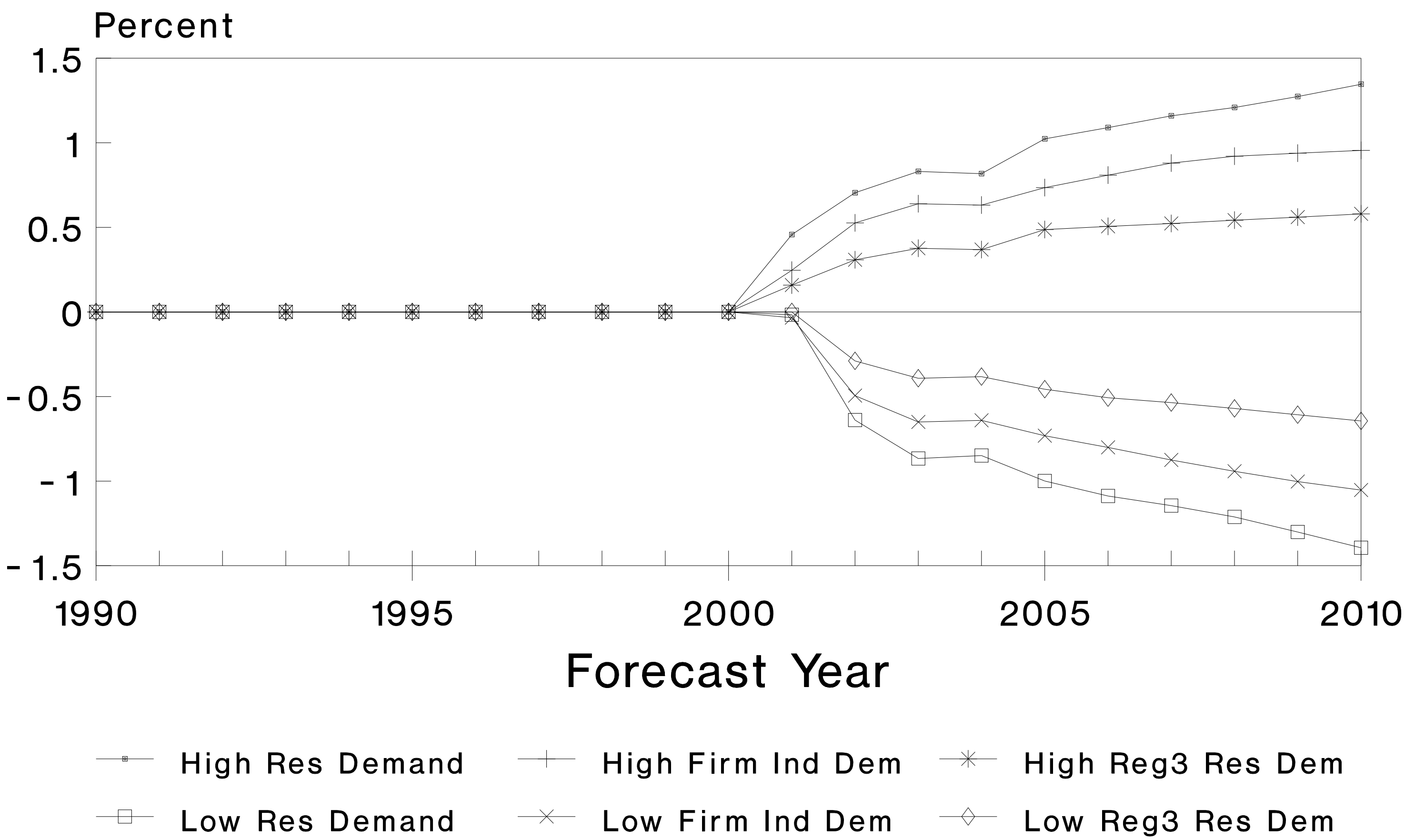
Variation relative to NGTDM2.D1014941

Fig.6. Variation in Pipeline Capacity



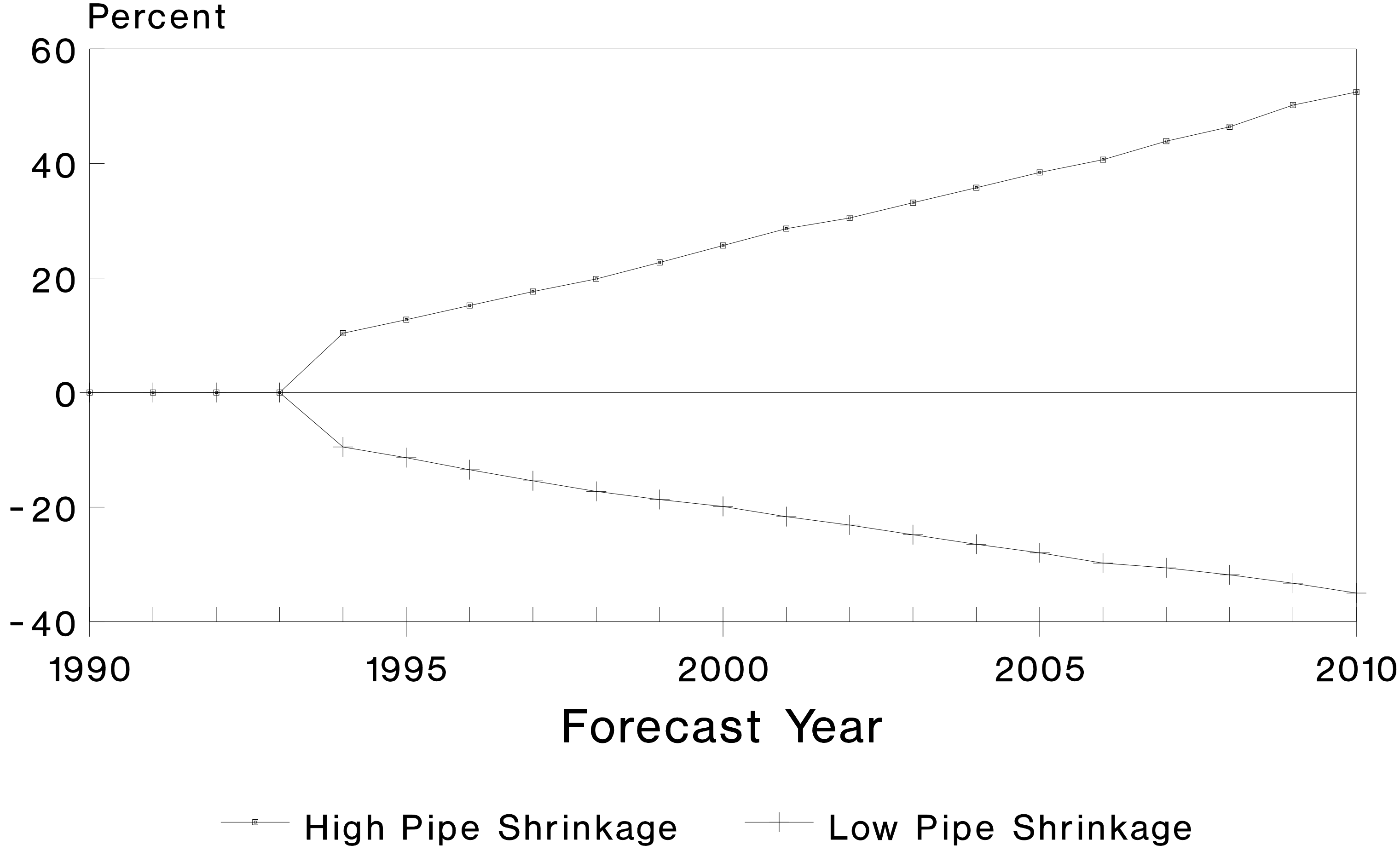
Variation relative to NGTDM2.D1014941

Fig.7. Variation in Pipeline Annual Revenue Requirement



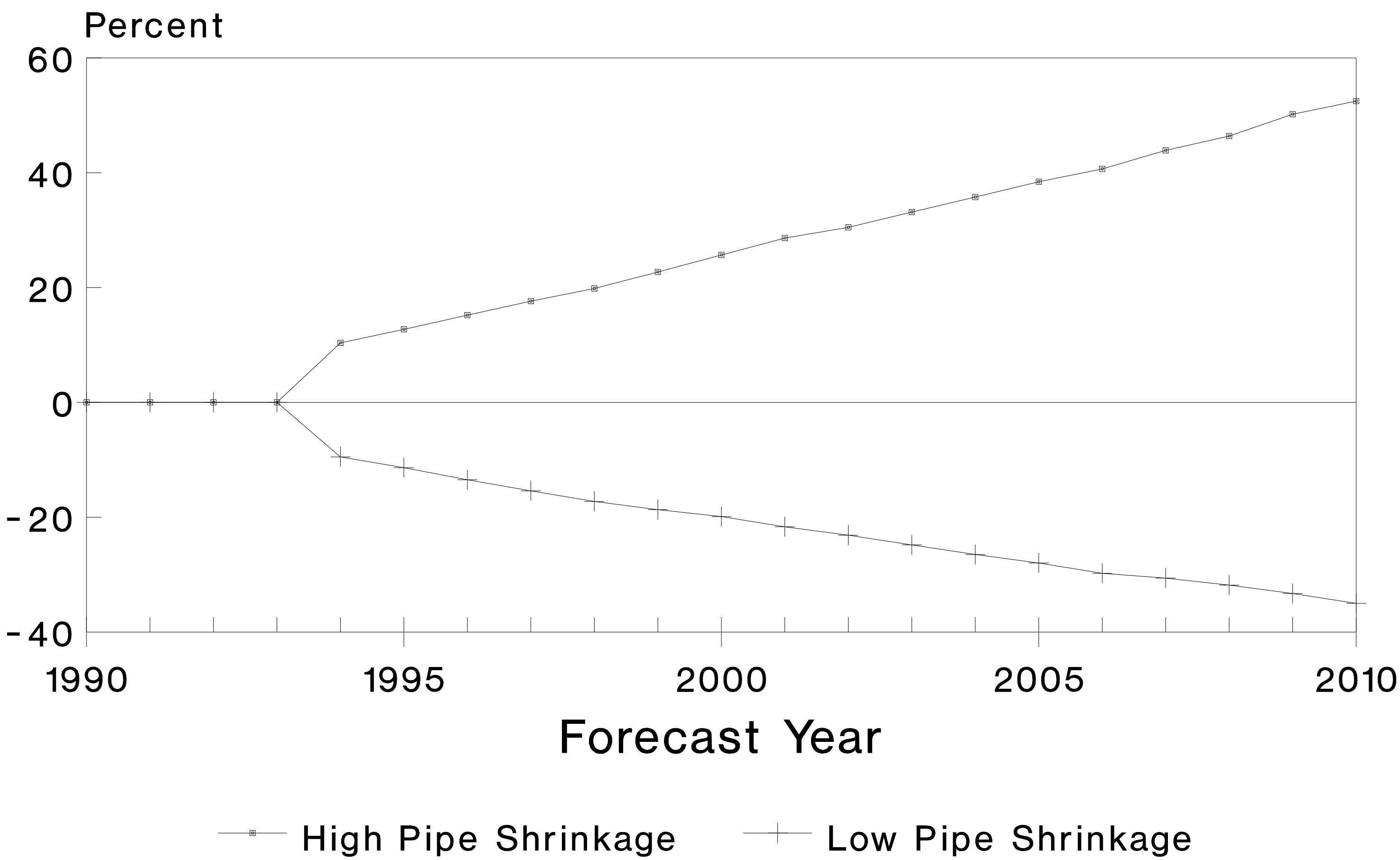
Variation relative to NGTDM2.D1014941

Fig.8. Variation in Pipeline Fuel Consumption due to Changes in Shrinkage



Variation relative to NGTDM2.D1014941

Fig.9. Variation in Carbon Emissions
in Response to Changes in Shrinkage



Variation relative to NGTDM2.D1014941