STATE OF NEWHAMPSHIRE
PUBLIC UTILITIES COMMISSION

DG 10-041

In the Matter of:
EnergyNorth Natural Gas, Inc. D/B/A/ National Grid NH
November 1, 2010 – October 31, 2015 Integrated Resource Plan

Direct Testimony
of
George R. McCluskey
Analyst

September 24, 2010

DIRECT TESTIMONY
OF
GEORGE R. McCLUSKEY

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STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc d/b/a National Grid NH) Docket No. DG10-041
2010 Integrated Resource Plan)

DIRECT TESTIMONY
OF
GEORGE R. McCLUSKEY

I. PROFESSIONAL EXPERIENCE & BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.
A. My name is George R. McCluskey, and my business address is the New Hampshire Public Utilities Commission ("Commission"), 21 South Fruit Street, Suite 10, Concord, New Hampshire 03301.

Q. WHAT IS YOUR POSITION WITH THE COMMISSION?
A. I am an analyst within the Electricity Division.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.
A. I am a utility ratemaking specialist with over 30 years experience in utility economics. I rejoined the Commission in March 2005 after working as a consultant for La Capra Associates for five years. Before joining La Capra, I directed the Commission's electric utility restructuring division and before that was manager of least cost planning, directing and supervising the review and implementation of electric utility least cost plans and

demand-side management programs. I have presented or filed testimony before state regulatory authorities in New Hampshire, Maine, Ohio and Arkansas and before the Federal Energy Regulatory Commission. A copy of my resume is included as Attachment GRM-1.

II. PURPOSE OF TESTIMONY & REQUIREMENTS OF ORDER NO. 24,941

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose is to present Staff's position on EnergyNorth Natural Gas, Inc.d/b/a National Grid NH ("ENGI" or "Company") resource planning, as described in its February 26, 2010 Integrated Resource Plan ("2010 IRP" or "filing"). An important factor in developing this position is the extent to which the Company complied with the requirements set forth in Order No. 24,941 in Docket DG 06-105.

Q. WHAT WERE THE REQUIREMENTS THAT CAME OUT OF ORDER NO. 24,941?

A. In Order No. 24,941, the Commission stated its expectations as to what the Company's next IRP filing should include:

1. Planning Period: the Commission stated that the planning period should be five (5) years but the length of the planning horizon should not limit the time period over which long-lived resource options are evaluated. Order at 18.

2. Demand Forecast: the Commission stated that the demand forecast should be based on the econometric forecasting model developed by the Company pursuant to the settlement approved in Order No. 24,531. Id.

3. Design Planning Standards: the Commission stated that, consistent with the settlement approved in Order No. 24,531, the Company:

a. should use the Monte Carlo weather forecasting analysis for establishing design planning standards and use the Monte Carlo simulation to:

i. develop a probability distribution for its weather and

ii. base its design planning standards on a statistical

analysis of that distribution. Order at 18-19.

b. should assess the capability of its resource portfolio to satisfy the design day and design year planning standards and meet demand requirements during a cold snap. Id.

c. should also evaluate how its portfolio would perform under alternative high and low demand scenarios. Id.

4. Capacity Reserve: the Commission stated the Company should address in its 2010 IRP "whether circumstances have changed such that a capacity reserve is warranted." Order at 19.

5. Supply-Side Resource Planning: the Commission stated the Company should "perform a systematic assessment of potentially available supply-side options based on a given set of realistic cost and demand forecasts." Id. at 20.

6. Demand-Side Resource Planning: the Commission stated the Company's IRP "should include a systematic evaluation of reasonably available demand-side management programs, including a description of the methodology for calculating avoided costs (i.e., cost savings) associated with not having to purchase additional gas supplies for constructing new peaking capacity." Id. at 21. The Commission noted that new information on the technical and economic

potential of demand-side resources in EnergyNorth's service area had recently become available in a report entitled: "Additional Opportunities for Energy Efficiency in New Hampshire" by DGS Associates and the Commission required National Grid "to use this information as the basis of its demand-side assessment in its next IRP filing." Id. at 21-22. The Commission went on to state that "[o]nce the avoided cost method is developed, the resulting avoided costs should be compared to the costs of implementing the demand-side resources." "As was the case with Public Service Company of New Hampshire, it is appropriate that EnergyNorth use the total resource cost test for determining which of the potential demand-side resource programs are cost effective." "Although we expect that the Company's evaluation of demand-side resources will be done on an equivalent basis with its evaluation of supply-side resources, we anticipate that this evaluation will reflect any differences in the reliability of demand-side measures compared to supply-side resources." Id. at 22.

7. Integration of Supply-Side and Demand-Side Resources: "the Company should describe its process for integrating demand-side and supply-side resources so that customer needs will be met at the lowest reasonable cost while maintaining reliability and taking into account other non-cost planning criteria." "Among other things, the Company should discuss how differences in the reliability of supply-side and demand-side resources are taken into account in the integration process and whether it expects to acquire the demand-side resources through Company-sponsored programs and/or programs acquired on its behalf by third parties through a request for proposal process."

8. The Commission stated that it will use the same criteria as it described in Order No. 19,546 for reviewing the next IRP, namely "completeness, comprehensiveness, integration, feasibility and adequacy of planning process."

Q. WHAT IS YOUR POSITION ON THE REQUIREMENTS SET FORTH BY THE COMMISSION IN ORDER NO. 24,941?

A. I have performed a detailed review of the Company's filing and found its positions on the planning period, the demand forecast, the design planning standards and the capacity reserve to be reasonable and consistent with the Commission's order. The remaining requirements, relating to supply-side and demand-side resource planning and integration, are the subjects of my testimony. Issues concerning the Company's supply-side resource assessment are presented in Section II: the first relates to excess supply capacity on the Company's system and whether its plans will produce cost savings for customers; the second issue relates to whether the Company's plans involve the replacement of expiring contracts with lower cost alternatives; and the third issue relates to the utilization of the Granite Ridge peaking contract. Issues concerning the Company's demand-side resource assessment are presented in Section III and have to do with the adequacy of the Company's analysis of the optimal mix of demand-side and supply-side resources in the resource portfolio.

Q. BEFORE YOU BEGIN YOUR CRITIQUE OF THE SUPPLY- AND DEMAND-SIDE RESOURCE ASSESSMENTS, PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. My conclusions are as follows:

Supply-Side Assessment

(1) Data included in the supply-side assessment indicate that the Company has more gas supply capacity on hand than needed during the planning period.

(2) Absent actions to eliminate or reduce this excess capacity, customers risk paying unnecessary gas supply costs.

(3) Retirement of some of the Company's peaking facilities could eliminate most of the excess and produce significant cost savings for customers.

(4) There is no indication in the filing or in responses to discovery that the Company plans to eliminate the excess capacity during the planning period.

(5) With the exception of one option involving firm supplies from the Marcellus shale development in West Virginia/Pennsylvania, the filing is silent on the opportunities for cost savings that involve the replacement of expiring supply contracts with lower cost alternatives.

(6) While the results of the Company's supply modeling point to continued use of its propane facilities, the same modeling indicates no role for the lower cost Granite Ridge peaking contract.

(7) There is no explanation in the filing for why higher cost propane is dispatched before Granite Ridge in the model runs.

Demand-side Assessment

(1) According to the Company, the results of the study conducted by GDS Associates for the Commission[1] into the potential for demand-side resources in New Hampshire indicate that at least 8.5 percent of its projected demand for gas in 2018 could be met economically with demand-side resources.

(2) Although the Potentially Obtainable Savings scenario is the least aggressive of the scenarios considered by GDS, the Company contends that a savings target of 8.5 percent by 2018 does not represent a practical target for supply planning purposes.

(3) The Company's modeling to determine the optimal mix of demand-side resources in its portfolio suffers from numerous flaws that limit the accuracy of the results. These include: (i) conducting the cost-benefit analysis over five-years instead of the useful life of the demand-side resources; (ii) neglecting to present value and sum the resulting annual cost savings; (iii) annualizing the cost of the demand-side resources; and (iv) neglecting to escalate the demand charges in gas supply contracts.

[1] Titled Additional Opportunities for Energy Efficiency in New Hampshire.

(4) The modeling also suffers from a number of unreasonable constraints that bias the results. Examples include limiting the number of supply contracts that can be displaced by demand-side resources and limiting the size of the demand-side resources.

(5) The results of the modeling are not supported by the costs of the individual demand and supply resources included in the analysis.

(6) The Company acknowledges that the problems with its modeling are the result of errors in the code to incorporate demand-side resources into the dispatch analysis.

In view of these conclusions, I recommend that the Commission: (i) find the 2010 IRP not adequate; and (ii) direct the Company to implement the recommendations in the remainder of this testimony.

Q. WHAT ARE THOSE RECOMMENDATIONS?

A. My key recommendations to the Commission are as follows:

(1) Open a proceeding to conduct a review of the Company's supply/demand balance over the 2010/11 through 2014/15 period and, if necessary, determine the prudence of carrying more capacity than needed to meet the reliability planning standard approved in this proceeding.

(2) Direct the Company to address explicitly in future IRP filings all issues related to excess capacity including identifying the amount of the excess, discussing the pros and cons of its elimination, and detailing the plans for handling the excess.

(3) Direct the Company to address in its next IRP the opportunities for gas cost savings that involve the replacement of expiring contracts with alternative supply options. Specifically, the filing should: (i) identify the potential supply alternatives; (ii) explain how the cost effectiveness of such alternatives are determined; and (ii) state whether requests for proposals, bilateral discussions or some other process will be used to acquire the replacement resources.

(4) Direct the Company to explain at the net CGA hearing why its resource plans do not include the Granite Ridge peaking contract.

(5) Direct the Company to file, within six months of the date of the final order in this proceeding, an updated resource mix analysis that: (i) incorporates the recommend methodological changes contained in this testimony; and (ii) identifies the least cost mix of supply- and demand-side resources.

III. STAFF'S REVIEW OF THE COMPANY'S ASSESSMENT OF AVAILABLE SUPPLY-SIDE RESOURCES

Q. THE COMMISSION DIRECTED THE COMPANY TO CONDUCT A SYSTEMATIC ASSESSMENT OF AVAILABLE SUPPLY-SIDE RESOURCES AND TO PRESENT THE RESULTS IN THE 2010 IRP. WHAT IS YOUR UNDERSTANDING OF THE TERM SYSTEMATIC ASSESSMENT?

A. As indicated in Order No. 24,941, the primary objective of the IRP is to develop a plan that allows the company to satisfy its obligation to meet the demands of their firm customers at the lowest overall cost consistent with maintaining supply reliability. Historically, most utilities have fulfilled that responsibility by operating a portfolio of gas supply contracts that comprise different start and end dates, different pricing terms, different pipelines to transport the gas, and different gas basins from which the gas is purchased.[2] If a utility's demand forecast indicates that its customers' future need for gas on the peak day exceeds its current supply capacity, the utility would perform a logical and unbiased economic comparison of the available supply-side resource options before making a decision to purchase the needed capacity from the least cost supplier. The term systematic assessment means simply that: the identification of the available supply-side options and an objective determination of the supply option that minimizes costs while maintaining supply reliability. Without such an economic comparison, the utility runs the risk of making resource decisions that prove costly over the long-term and increase costs to customers unnecessarily.

[2] More recently, demand-side resources have played a role in meeting gas demand at least cost. We address these resources in Section III.

Q. DOES THE COMPANY'S DEMAND FORECAST INDICATE A NEED FOR CAPACITY DURING THE PLANNING PERIOD?

A. No. On the contrary, the demand forecast indicates that the existing supply-side resources will exceed the projected design-day demand in each year of the five-year planning period resulting in excess capacity and the potential for unnecessary gas costs. However, because several existing resources are due to expire during this period or can be retired at any time, I believe the Company is well positioned to eliminate this excess. Additionally, the Company is well positioned to replace some of its high cost contracts with lower cost alternatives, which would be beneficial for customers.

Q. DOES THE FILING RECOGNIZE THESE COST SAVING OPPORTUNITIES?

A. No, not fully. The filing identifies the existing contracts that are set to expire during the planning period. The Company does not, however, acknowledge that excess capacity will exist during the period. As a consequence, the potential cost savings associated with eliminating or reducing the excess capacity are not addressed in the 2010-2015 IRP filing.

With one exception, the filing is silent on the additional opportunities for cost savings that involve the replacement of high cost expiring contracts with lower cost alternatives. The exception is the Marcellus shale development. The Company evaluated converting a portion of its Tennessee long-haul capacity with supply located in the Gulf of Mexico to Tennessee short-haul capacity with supply from the Marcellus shale basin.[3] The Company concluded that the cost

[3] The Marcellus shale formation extends from West Virginia into Ohio, Pennsylvania, and New York.

uncertainties of transporting gas from the Marcellus supply basin to Northeast markets are too great at this time to allow it to make the conversion.[4] I will have more to say about replacing expiring contracts with lower cost options later in this testimony.

A. Excess Capacity

Q. IF THE COMPANY'S IRP FILING DOES NOT ACKNOWLEDGE AN EXCESS CAPACITY SITUATION, WHY DO YOU BELIEVE IT EXISTS?

A. At a technical session in this proceeding, I provided the parties with an analysis that compared the projected design-day demands over the planning period with the Company's existing firm gas supplies. The information for this analysis was taken from the Company's 2010-2015 IRP filing. Using the same format but with revisions to certain quantities, the Company then responded with its own analysis of the balance between supply and demand over the planning period. That analysis, which is reproduced as Attachment GRM-2 attached, shows the excess in 2010/11 to be over 40,000 MMBtu per day or 29% of the projected design-day demand for that year. In 2014/15, the excess is smaller but still significant at over 31,000 MMBtu per day, or 21% of the Company's projected design-day demand.[5]

Q. WHAT IS THE CAUSE OF THIS EXCESS CAPACITY?

A. There are two primary reasons. The first is the addition of 30,000 MMBtu per day of new Tennessee capacity effective November 1, 2009 associated with the

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[4] A Company representative informed the parties that Tennessee is planning on filing a rate case at the FERC that would seek approval of a new rate design methodology that could lessen the impact of the Marcellus shale development on its business and reduce the cost savings that pipeline customers such as ENGI could realize from converting long-haul capacity to short-haul.

[5] Note that the Company analysis, which was provided as an attachment to Staff 1-49,calculated the percent excess by comparing it to the total capacity instead of the design-day demand. See Attachment GRM-3.

Concord Lateral expansion project. The second is the filing's lower design-day demand forecast compared to the forecast in the Concord Lateral proceeding, attributable largely to the recent downturn in the economy. These two factors have combined to produce the expected excess capacity.

Q. COULD THE EXCESS CAPACITY BE GREATER THAN INDICATED IN ATTACHMENT GRM-2?

A. Yes. Because the design-day demand projections in Attachment GRM-2 do not reflect the impact of demand-side programs installed during the planning period,[6] and because such incremental programs will reduce design-day demands below the levels projected, the capacity excesses could be greater than indicated.

Q. HOW MUCH GREATER?

A. Clearly, the extent of the reduction in design-day demand due to demand-side resources depends on the programs installed during the planning period. Using the programs and associated design-day demand reductions depicted in Chart IV-D-1[7] of the filing, I estimate the 2010/11 excess will increase to approximately 43,000 MMBtu per day or 31% of the projected design-day demand for that year. In comparison, the 2014/15 excess will increase to 38,000 MMBtu per day or 27% of the projected design-day demand. These quantities are also shown in Attachment GRM-2.

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[6] Only the impact of programs installed prior to the planning period is reflected in the demand projections.

[7] Since these demand reductions are based on normal weather conditions, the equivalent reductions under design-day weather conditions will be larger. Hence, the resulting design-day demand with DSM will be lower than indicated in Attachment GRM-2.

Q. DID YOU INQUIRE WHETHER THE COMPANY HAS ANY PLANS TO ELIMINATE OR REDUCE THE EXCESS CAPACITY?

A. Yes, I did. The Company said that as contracts expire or come up for renewal it intends to consider each asset and its contribution to the portfolio and determine whether to renew, replace or terminate the respective agreement. [8]

Q. HOW DO YOU INTERPRET THIS RESPONSE?

A. I interpret the response to say that the Company is not willing to commit at this time to eliminating the excess.

Q. WHAT ARE THE LIKELY EFFECTS OF A DECISION TO RETAIN THE EXCESS CAPACITY?

A. The most obvious effect will be to maintain costs at their current level instead of lowering them. Firm gas supply contracts typically include demand charges to recover the costs that the gas supplier incurs to ensure gas is produced whenever the customer requests it. Thus, if the Company elects to retain the excess capacity, customers will continue to pay these charges and forego the cost savings. For this reason, the Company's decision would be contrary to the primary objective of an IRP which is to develop and implement a plan that satisfies customer energy service needs at the lowest overall cost consistent with maintaining supply reliability.

Q. WILL THE COST INCREASE BE OFFSET BY AN INCREASE IN SUPPLY RELIABILITY?

[8]See response to Staff 1-50 attached to this testimony as Attachment GRM-4

[9]Customers would receive practically no reliability benefit from carrying more on-site peaking capacity if the cause of the curtailment is the failure of an interstate pipeline. The same is the case if the peaking facility interconnects with a distribution system that is isolated from the remainder of the system.

A. While it is generally true that customers are less likely to have their gas service curtailed the more firm resources the utility has at its disposal,[9] it is important to know that the reliability planning standard proposed by the Company in this proceeding, which requires an amount of capacity sufficient to meet the projected design-day demand, will itself produce "a reasonable level of reliability for firm customers."[10] This is so because the design-day demand is not a normal peak demand but a peak demand that occurs very infrequently and only under extreme weather conditions. Stated differently, the design-day demand standard proposed by the company will create a capacity reserve that serves the purpose of reducing the likelihood that service will be curtailed due to weather-related increases in demand. Furthermore, because the size of this reserve is based on a calculation that seeks to balance the benefits of increased reliability with the costs of incremental resources, there is no compelling reliability argument for retaining capacity in excess of the design-day demand. According to the Company, customers will already receive reliable gas service without the excess capacity.

B. Potential Cost Savings Associated with Reducing Excess Capacity

Q. WHAT IS THE POTENTIAL COST SAVINGS ASSOCIATED WITH ELIMINATING THE EXCESS?

A. The answer depends on which of its available supply-side resources the Company decides to reduce. Given the large number of supply contracts that are scheduled to expire during the planning period, a 38,000 MMBtu per day reduction in the Company's supply resources could be achieved in several ways. One option

[10] See 2010 IRP, Section III at 62.

would be to retire all of the Company's propane production and storage facilities except those located in Tilton.[11] This would reduce firm capacity by about 32,000 MMBtu per day. The remaining 6,000 MMBtu per day reduction could be achieved by retiring some of the Liquified Natural Gas (LNG) facilities located in Concord and Manchester. Unfortunately, the cost savings associated with these actions are not currently known because the Company has declined to gather the data and perform the analysis required to break down the $2.4 million annual cost that it is seeking to collect for these facilities in Docket DG 10-017 into its LNG and propane components.

Q. DO YOU BELIEVE THE COMPANY SHOULD CONSIDER RETIRING THE PROPANE FACILITIES?

A. Yes. In my opinion the propane facilities are the most likely candidate for retirement because the cost of the gas they produce is higher than the cost of any other resource in the Company's supply portfolio. In other words, there is no economic need to use these facilities to meet customer demand.

Q. HAS THE COMPANY USED THESE FACILITIES RECENTLY?

A. Prior to the expansion of the Concord Lateral on November 1, 2009, it was common for gas to be produced by the Nashua and Manchester propane facilities on multiple winter days. In January and February of 2008, for example, those facilities produced gas on 21 separate days. In the same months of 2009 the number was 15 days. After the expansion of the Concord Lateral, the comparable number for 2010 was 4 days.

[11] The Tilton propane facilities are required for distribution pressure maintenance purposes.

Q. IF THE COMPANY HAD TOO MUCH CAPACITY AT THE BEGINNING OF 2010 AND THE COST TO PRODUCE PROPANE IS HIGHER THAN THE COST OF ANY OTHER SUPPLY RESOURCE, WHY WOULD THE COMPANY DISPATCH THOSE FACILITIES AT ALL?

A. There is no economic reason to dispatch those facilities. Dispatching them will result in the under utilization of lower cost available supply-side resources. I will have more to say about this issue later in this section.

Q. HAVE YOU ESTIMATED THE COSTS THAT COULD BE SAVED BY RETIRING THE LNG AND PROPANE PEAKING FACILITIES?

A. Absent detailed accounting data that would allow the annual revenue requirement for the propane facilities to be calculated, any estimate would necessarily be inexact. Nonetheless, starting with the $2.4 million revenue requirement requested by the Company, I estimate using the relative vaporization capacities of the LNG and propane peaking facilities that the gross cost savings associated with retirement of the Nashua and Manchester propane facilities could be in the region of $1.4 million per year.[12] If some of the LNG facilities also have to be retired to balance supply with demand, the savings could increase to about $1.6 million per year. The net cost savings, however, could be somewhat less due to the likelihood that any undepreciated investment in the retired facilities would be amortized and collected over time.

Q. IS AN ANNUAL COST SAVINGS OF $1.6 MILLION SIGNIFICANT?

[12] This estimate assumes among other things that the $2.4 million cost is an accurate estimate of the revenue requirements associated with the peaking facilities. In technical session discussions, the Company stated that the number is not the result of a detailed bottom-up calculation based on the book values of the individual propane and LNG assets but a generic calculation that begins with the combined gross investment for LNG and propane peaking facilities.

A. Yes, $1.6 million represents approximately 2 percent of the total gas cost for 2010. Moreover, any amount that customers can avoid as a result of good utility practice should be regarded as significant.

Q. WHAT ARE THE COMPONENTS OF THE $1.6 MILLION COST SAVINGS?

A. Most of the $1.6 million will comprise return on investment and depreciation.

Q. IS IT YOUR INTENTION TO REPLACE THE ABOVE SAVINGS ESTIMATE WITH A MORE ACCURATE NUMBER BASED ON COMPANY ACCOUNTING RECORDS?

A. Yes. Staff continues to seek the relevant information from the Company and, if successful, will update the testimony prior to the hearing.

C. Contract Replacement

Q. ABOVE, YOU SAID THAT WITH THE EXCEPTION OF THE MARCELLUS SHALE DEVELOPMENT THE FILING IS SILENT ON THE ADDITIONAL OPPORTUNITIES FOR COST SAVINGS INVOLVING REPLACING EXPIRING CONTRACTS WITH LOWER COST ALTERNATIVES. PLEASE ELABORATE.

A. In Table IV-C-3 of the filing, the Company identifies five gas supply contracts,[13] with a total daily capacity of 86,000 MMBtu, that are scheduled to expire during the planning period. While it acknowledged in Attachment GRM-3 that important decisions will have to be made on the renewal or replacement of these contracts, the Company does not provide any information on how those decisions will be made. Specifically, the Company does not indicate whether it intends to: (i) renew the expiring contracts or replace them with lower cost alternative gas supply contracts while leaving the transportation contracts in place; or (ii) replace the existing gas supply and transportation contracts with lower cost alternative gas

[13] Excluding Distrigas.

supply and transportation contracts. The Company also does not indicate in its filing whether it plans on using requests for proposals, bilateral discussions, or some other process to determine the identity of the new gas suppliers. Finally, the selection criteria underlying each process are not identified or discussed. Without this type of detail, it is difficult for Staff to conclude that the Company is performing a systematic assessment of its available supply-side resources in a complete and comprehensive manner as required by Order No. 24,941. For this reason, Staff recommends the Company provide this information in its next IRP.

D. Granite Ridge

Q. DO YOU HAVE OTHER CONCERNS REGARDING THE COMPANY'S SUPPLY-SIDE ASSESSMENT?

A. Yes, I am concerned about the planned underutilization of the Granite Ridge peaking contract. This contract provides up to 15,000 MMBtus per day of firm gas for a total of 450,000 MMBtus during the months of December, January, and February. Despite the fact that the estimated commodity cost for this contract for the 2009/10 winter period was substantially below the corresponding costs for LNG and propane,[14] none of the SENDOUT model runs conducted by the Company resulted in the dispatch of Granite Ridge whereas both higher-cost resources were dispatched. The dispatch of propane before Granite Ridge in these runs is particularly troubling to Staff given that the variable cost of the former is about twice that of the latter.[15]

Q. DID THE COMPANY EXPLAIN WHY IT DOES NOT EXPECT TO UTILIZE THE GRANITE RIDGE CONTRACT OVER THE PLANNING PERIOD?

[14] See Table 3 below.
[15] Ibid. Note also that the estimated price differential widened for the 2010/11 winter period.

A. No, the role of the contract in the Company's supply plans is not addressed in the IRP.

Q. HAS THE COMPANY UTILIZED THE GRANITE RIDGE CONTRACT RECENTLY?

A. No. I reviewed the Company's Cost of Gas reconciliation filings for the 2008/09 and 2009/10 winter periods and found that the Company did not utilize the contract during those periods.

Q. COULD AN EXPLANATION BE THAT THE ACTUAL PRICE OF GAS UNDER THE GRANITE RIDGE CONTRACT WAS HIGHER THAN THE COST OF PROPANE?

A. I do not think so. Using the pricing formula in effect during the 2007/08 winter period, I calculated that the variable cost of gas under the contract ranged from $8.16 to $12.50 per MMBtu on the days in 2009/10 when propane was produced. The average variable cost of propane on the same days was $14.60 per MMBtu. These data indicate that the actual price of gas under the Granite Ridge contract was lower than the variable cost of propane.

Q. WHAT IS YOUR POSITION REGARDING THE GRANITE RIDGE CONTRACT?

A. The role of the Granite Ridge contract in the Company's future supply plans should be addressed in its next IRP. The explanation for why the contract has not been utilized in the recent past should be provided in the docket for the 2010/11 winter Cost of Gas proceeding.

IV. STAFF'S REVIEW OF THE COMPANY'S ASSESSMENT OF AVAILABLE DEMAND-SIDE RESOURCES

Q. IN ORDER NO. 24,941, THE COMMISSION DIRECTED THE COMPANY TO CONDUCT A SYSTEMATIC EVALUATION OF REASONABLY AVAILABLE DEMAND-SIDE RESOURCE OPTIONS AND TO PRESENT THE RESULTS IN ITS NEXT IRP. WHAT IS YOUR UNDERSTANDING OF THE TERM SYSTEMATIC EVALUATION?

A. The term systematic evaluation of demand-side resource options means the same as systematic assessment of supply-side resource options; namely, conducting an economic comparison of reasonably available demand-side options that is both logical and unbiased. There is, however, one important difference. An economic comparison of supply-side options involves comparing one supply-side option with another until the least cost option is identified. In contrast, an economic comparison of demand-side options involve comparing each option with the least cost supply-side option[16] to determine the optimal amount of cost-effective demand-side resources to be included in the Company's portfolio.

Q. DO YOU HAVE INDEPENENT SUPPORT FOR THIS VIEW?

A. Yes. Using the least cost supply-side option as the avoided cost in economic comparisons of demand-side options is recommended by NARUC in its Primer on Gas Integrated Resource Planning.[17]

Q. DID THE COMMISSION REQUIRE ANYTHING OTHER THAN A SYSTEMATIC EVALUATION?

A. Yes, the Commission also directed that: (i) the demand-side assessment be based on information on the technical and economic potential of demand-side resources contained in the report "Additional Opportunities for Energy Efficiency in New Hampshire" prepared by GDS Associates for the Commission ("GDS Report");

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[16] The least cost supply-side option in this analysis is also known as the avoided cost.

[17] See page 33.

and (ii) a description of the methodology for determining demand-side resource cost-effectiveness be provided.

A. GDS Report Recommendations

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF THE GDS REPORT AS THEY RELATE TO ENGI.

A. Among other things, GDS Associates evaluated the technical potential, the maximum achievable potential, and the maximum achievable cost effective potential for natural gas savings in ENGI's service area.[18] The results of these evaluations are presented in Table 1 below along with the results from the "potentially obtainable savings" scenario, which reflects that portion of the maximum achievable cost effective potential that might be achievable after consideration of customer behavior.

Table 1
GDS Report
Savings Potential (%)*

	Technical Potential	Maximum Achievable Potential	Max. Ach. Cost Eff. Potential	Potentially Obtainable Savings
Residential	35.7%	22.0%	18.6%	10.70%
Commercial	26.0%	22.0%	17.0%	7.0%
Industrial	11.2%	9.0%	9.0%	4.4%

* Savings in 2018 as a percent of total 2018 class demand.

[18] Technical Potential is defined by GDS as the complete and immediate penetration of all efficiency measures analyzed in applications where they were deemed technically feasible from an engineering perspective.
Maximum Achievable Potential is defined as the maximum penetration of an efficient measure that would be adopted absent consideration of cost or customer behavior. The term "achievable" refers to efficiency measure penetration, based on estimates of New Hampshire-specific building stock, energy using equipment saturations, and realistic efficiency penetration levels that can be achieved by 2018 if all remaining standard efficiency equipment were to be replaced on burnout and where all new construction and major renovation activities in the state were done using energy efficient equipment and construction/installation practices.
Maximum Achievable Cost Effective Potential is defined as the portion of the maximum achievable potential that is cost effective according to the Total Resource Cost Test.

Under the scenario considered most realistic by the Company, namely the Potentially Obtainable Savings scenario, the GDS Report concluded that by 2018 demand-side management savings could amount to approximately 10.7 percent of ENGI's expected residential demand in that year, 7.0 percent of expected commercial demand, and 4.4 percent of expected industrial demand. Because the Company combines its commercial and industrial classes, it determined that the weighted average percentage for these two classes is 6.5 percent. Applying the percentages for the residential and C&I classes to 2009/10 volumes, the Company calculated that 8.5 percent of the expected total demand for gas in 2018 could be met economically with demand-side resources.

Q. DOES ACHIEVEMENT OF THE POTENTIALLY OBTAINABLE SAVINGS TARGET REQUIRE INSTALLATION OF SIGNIFICANT NUMBERS OF EFFICIENCY MEASURES NOT CURRENTLY OFFERED BY THE COMPANY?

A. No, the GDS Report found that a significant majority of the natural gas efficiency measures identified in the technical potential study have already been incorporated in the programs offered by the Company.[19] The potential for additional savings derives in large part from the related finding that there is a substantial opportunity for further penetration of existing energy efficiency measures in all customer sectors.

B. Company's Response of GDS Report Recommendations

[19] Measures that are cost effective but not currently offered by the Company include ENERGY STAR dishwashers and close dryers, boiler tune up, and high efficiency cooking equipment.GDS Report at 135, Table 76.

Q. WHAT WAS THE COMPANY'S RESPONSE TO THE FINDING THAT 8.5% OF ITS EXPECTED 2018 GAS DEMAND COULD BE MET ECONOMICALLY WITH DEMAND-SIDE RESOURCES?

A. The Company said that a savings potential of this magnitude does not represent a practical target for supply planning purposes.

Q. WHAT IS THE BASIS FOR THE COMPANY'S OPINION?

A. The Company said that the savings potential is equivalent to more than 8.7 times the 2010 goal of 124,318 MMBtu in the Company's currently approved energy efficiency program. Assuming the 2010 ratio of savings to participants remains the same each year, achievement of the savings target would require approximately 57% of residential customers and 50% of C&I customers to participate in demand-side programs by 2018. It is these percentages that appear to be the basis of the Company's unwillingness to use the GDS savings potential for supply planning purposes.

C. Staff's Comments

Q. DO YOU SHARE THAT CONCERN?

While I agree that the above mentioned participation percentages are high and would require a major and sustained effort on the part of the Company,[20] a strong case could be made that a high level of participation is needed to address the primary weakness of utility-funded demand-side resource programs: namely, the payment by non-participants of most of the program costs and the receipt by participants of most of the benefits. That aside, the Company has provided no evidence that these participation percentages could not be achieved. More

[20] The GDS Report concluded that this level of savings would require "a concerted, sustained campaign involving aggressive programs and market interventions."

importantly, as the following discussion makes clear, the Company has not specified what it considers to be achievable participation percentages.

D. Company's Resource Mix Modeling

Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINED THE PERCENTAGE OF PROJECTED GAS DEMAND THAT COULD BE REASONABLY AND ECONOMICALLY MET WITH DEMAND-SIDE RESOURCES.

A. Instead of identifying the least cost supply-side option and then the demand-side resources that compare favorably to it, the Company elected to use the Ventyx SENDOUT model to determine the optimal mix of supply-side and demand-side resources. While this approach does not explicitly identify the avoided cost, it can determine the optimal mix of demand-side resources.

The SENDOUT model can be used in one of two ways: the optimization mode or the resource mix mode. In the optimization mode, the model is used to determine the best use of an existing set of contracts (supply-side and demand-side) to meet a specific demand. That is, it solves for the least cost dispatch of contracts given existing contracts and system-operating constraints and a specific demand. In this mode, contracts are dispatched based on their variable costs with demand charges fixed.

In the resource mix mode, the model is used to determine the optimal portfolio to meet the specific demand. To determine the optimal portfolio, the model analyze a set of existing and new contracts to determine the combination that results in the lowest total cost over time, taking into account the termination dates of existing contracts and the variable costs and demand charges of the existing and new contracts. In other words, all costs are considered variable in the resource mix mode.

To support its modeling, the Company developed three demand scenarios (a low-demand case, a base-demand case, and a high-demand case) and three levels of demand-side resource penetration (low-case, base-case, and high-case). The model was then run with different combinations of these demand and demand-side resource scenarios.[21] All but one of these model runs were executed in the optimization mode.[22]

Q. HOW DOES THE SENDOUT MODEL HANDLE DEMAND-SIDE RESOURCES?

A. The impacts of demand-side resources were modeled by the Company as new supply resources that have the potential to displace existing supply resources.[23] Each demand-side resource was given its own cost and supply characteristics. This is a change from the practice in previous IRPs were demand-side resources had no impact on supply planning because they were modeled as reductions in the demand for gas.

Q. PLEASE DESCRIBE THE SINGLE MODEL RUN IN THE RESOURCE MIX MODE.

A. The Company used the resource mix mode to evaluate the conversion of a portion of the Tennessee long-haul transportation capacity to short-haul from the Marcellus shale basin as well as determine the optimal mix of demand-side

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[21] Note that the demand forecasts are presented under both normal and design-year weather conditions. Thus, the total number of demand scenarios is six rather than three.

[22] See 2010 IRP, Section IV at 3 (Revised)

[23] Note that demand-side resources were not modeled as alternatives to new supply-side resources because the Company determined that existing supplies are adequate to meet the projected demands of its customers.

resources. The run was executed using the base-demand case under design-year weather conditions.

Q. PLEASE DIFFERENTIATE THE DEMAND-SIDE RESOURCES MODELED BY THE COMPANY.

A. For its low-case penetration scenario, the Company used a resource with an annual demand reduction of 79,198 MMBtu and a cost of $3,258,139 for residential and C&I customers combined. The quantities allegedly represent the annual average of the 2004 through 2009 programs. For its base-case penetration scenario, which begins in 2009/10, the Company used a resource with the characteristics of the 2010 program; namely, an annual demand reduction of 124,318 MMBtu and a total cost of $9,527,217. For its high-case penetration scenario, which begins in 2010/11, the Company developed three demand-side resource options for each of the residential and C&I customer groups. The Company refers to these options as tiers, which are distinguished by different levels of cost and demand reduction. The Tier 1 option for the residential (C&I) group is a demand-side resource with cost and demand reduction characteristics equal to the average of the 2004/2009 residential (C&I) programs. The Tier 2 cost and demand reduction characteristics for the residential (C&I) group are calculated as the difference between the 2004 through 2009 residential (C&I) program cost and demand reduction averages and the 2010 residential (C&I) program averages. Lastly, the Tier 3 cost and demand reduction characteristics are based on programs the Company believes it can readily increase in scale over the planning period. The three tiers combined produce a maximum annual demand reduction of 146,335 MMBtu.

Q. WHAT ARE THE UNIT COSTS FOR THESE DEMAND-SIDE RESOURCES?

A. The unit costs as presented by the Company are shown in Table 2 below.

Table 2
DSM Scenarios

Unit Costs
($/MMBtu)

	Low-Case Penetration	Base-Case Penetration	High-Case Penetration Tier 1	High-Case Penetration Tier 2	High-Case Penetration Tier 3
Residential	4.33	5.65	4.33	7.51	5.74
C&I	1.88	4.78	1.88	10.63	4.05
Total	2.74	5.11	2.74	9.26	4.56

E. Staff's Opinion on Company's Resource Mix Modeling

Q. DO YOU AGREE WITH THESE COST ESTIMATES?

A. No. Regarding the low-case demand-side resource, I found that the 2004-09 average annual demand reductions shown in Chart IV-D-1 for the residential and C&I groups were calculated incorrectly. My calculations indicate that the demand reductions are less than claimed resulting in unit costs of $4.70 and $2.05 per lifetime MMBtu respectively based on an assumed 15 year useful life. With respect to the base-case demand-side resource, I noted earlier that it was given the demand reduction and cost characteristics of the 2010 program. Consequently, it would be reasonable to expect that the unit costs for this resource match the unit costs for the 2010 program. This, unfortunately, is not the case.

Although the base-case resource and the 2010 program have the same annual demand reductions, the Company used a useful life for the base-case resource that does not match the life for the 2010 program. The useful life is too short.[24] As a consequence, the lifetime savings for the base-case resource are too low which results in the base-case resource having higher unit costs than the 2010 program. It also means that the base-case resource is less cost effective.

Q. WHAT IS THE DIFFERENCE?

A. The unit costs for the residential and C&I components of the 2010 program are $4.55 and $4.45 per MMBtu respectively. The corresponding base-case resource unit costs are $5.65 and $4.78 per MMBtu.

Q. IS THE HIGH-CASE DEMAND-SIDE RESOURCE ALSO BASED ON A 15 YEAR USEFUL LIFE?

A. Yes, the Company used 15 years for all of its demand-side resources.

Q. WHAT ARE THE IMPLICATIONS OF THESE FINDINGS?

A. The findings raise questions about the validity of the modeling results.

Q. THOSE COMMENTS ASIDE, HOW DO THE UNIT COSTS OF THE MODELED DEMAND-SIDE RESOURCES COMPARE WITH THE COSTS OF THE COMPANY'S EXISTING SUPPLY RESOURCES?

A. In Table 3 below, I show the commodity and associated volumetric transportation charges for each gas supply resource excluding underground storage. The sum of these charges is the variable cost that would be avoided if lower cost demand-side resources were dispatched. A comparison of Tables 2 and 3 reveals that the low-

[24] The base case resource has a 15 year life whereas the 2010 program is based on an average life of 17.1 years.

case and base-case demand-side resources plus two of the three of the high-case demand-side resource tiers are less costly than all of the existing gas supplies. Further, if the demand charges in each supply contract are also taken into account, the gas supply savings from using demand-side resources would be greater than indicated by the differences in Tables 2 and 3.

Table 3
Existing Gas Supply Resources

Winter 2009/10 Commodity & Volumetric Transportation Charges
($/MMBtu)

	Commodity Charge	Transportation Charge	Total Charge
Dawn Supply	5.751	0.2591	6.010
Niagara Supply	5.802	0.1972	5.999
TGP Long-Haul	5.411	0.5831	5.994
Dracut	6.661	0.1248	6.786
PNGTS	6.161	0.0000	6.161
Granite Ridge	6.552	0.0000	6.552
LNG	7.320	0.0000	7.320
Propane	14.622	0.0000	14.622

Q. WHAT ARE THE RESULTS OF THE COMPANY'S RESOURCE MIX MODELING?

A. As noted above, the Company executed one model run in the resource mix mode using the base-demand case under design-year weather conditions. The results from that run are shown in Table 4 below. In 2010/11, the model dispatched the C&I component of Tier 1 only producing a demand reduction of 53.6 MMBtu.[25] All other tier components were judged to be uneconomic and hence not dispatched. The 53.6 MMBtu demand reduction when added to the reductions

[25] See Attachment to Staff 1-35(Supp.), which is reproduced here as Attachment GRM-5

due to the low-case and base-case programs resulted in an overall reduction of 268 MMBtu. In year 2011/12, both components of Tier 1 were dispatched for a cumulative demand reduction of 168.5 MMBtu and an overall reduction of 384 MMBtu. In years 2012/13, 2013/14, and 2014/15, all tier components with the exception of the C&I component of Tier 2 were dispatched producing overall annual demand reductions of 600 MMBtu, 729 MMBtu, and 858 MMBtu. In terms of percentages, these cumulative annual reductions range from 1.9% in 2010/11 to 5.5% in 2014/15.

Table 4

Design-Year Requirements
Under Resource Mix Runs
(MMBtu)

Resource Mix Run	2010-11	2011-12	2012-13	2013-14	2014-15
Without DSM	14,149,822	14,608,833	14,904,982	15,265,185	15,625,288
With DSM	13,881,674	14,224,701	14,304,338	14,535,825	14,767,211
Cumulative Reduction	268,148	384,132	600,644	729,360	858,077
Cumulative Reduction %	1.9%	2.6%	4.0%	4.8%	5.5%

Q. DO THESE RESULTS MAKE MUCH SENSE?

A. No. As already noted, two of the three demand-side resource tiers are more cost-effective than all of the existing gas contracts based on commodity costs alone. In contrast, the components of the Tier 2 resource are less cost-effective than all of the contracts except propane. Based on this information, an efficiently functioning model would have dispatched Tiers 1 and 3 each year in both the summer and winter period and Tier 2 during the winter only.

Q. DID THE COMPANY EXPLAIN THESE IRREGULARITIES?

A. Following lengthy discovery on its modeling and several conference calls, the Company informed the parties that it had concluded that the demand-side resource code in the SENDOUT model was not functioning correctly when operated in the resource mix mode. The Company also said that the problems with the model could not be fixed before the parties were scheduled to file their testimony. As a consequence, the Company was not able to identify the optimal mix of demand-side resources for its portfolio as required by the Commission in Order No. 24,941

Q. DO YOU HAVE OTHER CONCERNS REGARDING THE RESOURCE MIX MODELING?

A. Yes, I have two. First, even if the SENDOUT model had been functioning correctly, the quantity of gas displaced by the demand-side resources in the resource mix mode would not be optimal.[26] This is because the SENDOUT model does not have the capability to dispatch any particular tier multiple times if it is economic to do so.[27] Without that capability, the maximum quantity of gas displaced in the resource mix mode will be limited by the size of tiers developed by the Company instead of by the cost effectiveness of those tiers relative to the marginal supply resources.

Second, the resource mix analysis is unreasonably hindered by several illogical constraints. For example, despite having some of the highest commodity costs in the portfolio, the Company decided against treating the Granite Ridge, LNG, and propane contracts as variable resources in the SENDOUT model on the ground

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[26] The optimal amount is the amount that minimizes the cost of the portfolio.

[27] See Company response to Staff 4-4. See Attachment GRM-6 It should also be noted that the SENDOUT model does not have the capability to dispatch part of a tier.

that those contracts are peaking resources with characteristics different from demand-side resources. While it may be accurate to say that some and maybe most demand-side resources have demand reduction characteristics that do not provide a good match to peaking resources, this is not the issue in this type of analysis. The issue is whether existing base load or peaking contracts can be displaced cost-effectively by demand-side resources. It matters little that a new demand-side resource might displace more commodity than is supplied by the peaking resource that is being replaced provided the net effect is to lower the total cost of meeting customers' demand. Also, because the peaking resources have higher commodity costs than the Dawn, Niagara, and Gulf Coast contracts, the amount of supply-side resources that could potentially be displaced by demand-side resources would obviously be greater if the peaking resources are classified in the analysis as variable instead of fixed.

F. The Company's Cost-Benefit Analysis Underlying Resource Mix Modeling.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE COST-BENEFIT ANALYSIS UNDERLYING THE COMPANY'S RESOURCE MIX MODELING.

A. In the resource mix mode, certain supply contracts along with the associated transportation contracts were assumed fixed while others were classified as variable contracts. Initially, the expiring Dawn, Niagara, and Gulf Coast contracts were identified as the variable contracts; meaning they could potentially be displaced by more cost-effective demand-side resources. Subsequently, the parties were informed that the Gulf Coast contracts were excluded from this analysis because the Company determined that the current version of the

SENDOUT model could not handle those contracts as variable resources. The Company also clarified that the demand costs under the Dawn and Niagara contracts plus the commodity costs under all contracts were classified as variable costs in its resource mix run.

Because a demand-side resource continues to produce savings throughout its useful life, the investment decision should be based on a multi-year calculation that compares the cost of acquiring the demand-side resource with the corresponding lifetime gas supply cost savings.[28] To perform this cost-benefit analysis correctly, the gas supply costs (i.e., demand and commodity costs) associated with variable contracts must be escalated over the life of the demand-side resource in a way that reflects the expected increase in those cost components. In addition, the resulting annual cost savings (i.e., the avoided demand and commodity costs) must be present valued and summed. The Company, however, elected to use a simpler but much less precise approach that involves comparing the annual cost of the demand-side resources and the annual cost savings in each year of the five year planning period instead of over the useful life of the resource.[29] In calculating the annual cost savings, the Company also decided against escalating the contract demand charges and even omitted to present value and sum the net annual savings. Thus, under the Company's formulation, demand-side resources would be deemed cost effective if annual cost savings exceed annual resource costs in each year of the planning period.

[28] The Company's economic analysis assumes a 15 year useful life for each demand-side resource.
[29] The annual cost of a demand-side resource was calculated by dividing the total cost of that resource by its assumed useful life.

G. Staff's Comments on the Company's Cost-Benefit Analysis Underlying Resource Mix Modeling

Q. DO YOU SUPPORT THE COMPANY'S COST-BENEFIT ANALYSIS?

A. No, it has several obvious weaknesses. Because the approach only analyzes costs and benefits over the first 5 years of the assumed 15 year life of the resources, it could result in the Company making an incorrect investment decision. This would be the case if, for example, the demand-side resources produced net cost savings during each year of the planning period but net cost increases during the remaining years such that the sum of the cost increases exceeded the sum of the cost savings.

Also, the failure to escalate the demand charges would tend to understate the cost savings and hence bias the result against demand-side resources. In contrast, the failure to present value the annual cost savings would tend to overstate the cost savings and hence bias the result in favor of demand-side resources. Finally, the failure to sum the net annual cost savings is a major omission that could lead to inappropriate and non cost-effective investment decisions.

Q. FINALLY, DID THE COMPANY BASE ITS EVALUATION OF DEMAND-SIDE RESOURCES ON PROGRAM INFORMATION CONTAINED IN THE GDS REPORT AS REQUIRED BY THE COMMISSION IN ORDER NO. 24,941?

A. Yes. Because the GDS study found that a significant majority of the natural gas efficiency measures identified in the technical potential study had already been incorporated in the programs offered by the Company, I believe the Company's decision to model its demand-side resource options on existing programs conforms to the Commission's directive.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?
A. Yes.

GEORGE R. McCLUSKEY

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Analyst

George McCluskey is a ratemaking specialist with over 30 years experience in utility economics. Since rejoining the New Hampshire Public Utilities Commission ("NHPUC.") in 2005, he has worked on IRP, default service and distributed generation issues in the electric sector and IRP, lead/lag and cost allocation issues in the gas sector. While at La Capra Associates, a Boston-based consulting firm specializing in electric industry restructuring, wholesale and retail power procurement, market price and risk analysis, and power systems models and planning methods, he provided strategic advice to numerous clients on a variety of issues. Prior to joining La Capra Associates, Mr. McCluskey directed the electric utility restructuring division of the NHPUC and before that was manager of least cost planning, directing and supervising the review and implementation of electric and gas utility least cost plans and demand-side management programs. He has testified as an expert witness in numerous electric and gas cases before state and federal regulatory agencies.

ACCOMPLISHMENTS

Recent project experience includes:

Staff of the New Hampshire Public Utilities Commission – Expert testimony before NHPUC regarding the cost effectiveness of distributed generation resources in a case involving Unitil Energy Systems.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before NHPUC regarding default service design and pricing issues in case involving Unitil Energy Systems.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before Maine Public Utilities Commission regarding interstate allocation of natural gas capacity costs in case involving Northern Utilities.

Staff of the Arkansas Public Service Commission – Analysis and case support regarding Entergy Arkansas Inc.'s application to transfer ownership and control of its transmission assets to a Transco. Also analyzed Entergy Arkansas Inc.'s stranded generation cost claims.

Massachusetts Technology Collaborative – Evaluated proposals by renewable resource developers to sell Renewable Energy Credits to MTC in reponse to 2003 RFP.

Pennsylvania Office of the Consumer Advocate – Analysis and case support regarding horizontal and vertical market power related issues in the PECO/Unicom merger proceeding. Also advised on cost-of-service, cost allocation and rate design issues in FERC base rate case for interstate natural gas pipeline company.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before the NHPUC regarding stranded cost issues in Restructuring Settlement Agreement submitted by Public Service Company of New Hampshire and various settling parties. Testimony presents an analysis of PSNH's stranded costs and makes recommendations regarding the recoverability of such costs.

Town of Waterford, CT – Advisory and expert witness services in litigation to determine property tax assessment of for nuclear power plant.

Washington Electric Cooperative, Vt – Prepared report on external obsolescence in rural distribution systems in property tax case.

New Hampshire Public Utilities Commission - Expert testimony on behalf of the NHPUC before the Federal Energy Regulatory Commission regarding the Order 888 calculation of wholesale stranded costs for utilities receiving partial requirements power supply service.

Ohio Consumer Council - Expert testimony regarding the transition cost recovery requests submitted by the AEP companies, including a critique of the DCF and revenues lost approaches to generation asset valuation.

EXPERIENCE

New Hampshire Public Utilities Commission (2005 to Present)
Analyst, Electricity Division

La Capra Associates (1999 to 2005)
Senior Consultant

New Hampshire Public Utilities Commission (1987 – 1999)
Director, Electric Utilities Restructuring Division
Manager, Least Cost Planning
Analyst, Economics Department

Electricity Council, London, England (1977-1984)
Pricing Specialist, Commercial Department
Information Officer, Secretary’s Office

EDUCATION:

Ph.D. candidate in Theoretical Plasma Physics, University of Sussex Space Physics Laboratory.
Withdrew in 1977 to accept position with the Electricity Council.

B.S., University of Sussex, England, 1975.
Theoretical Physics

ATTACHMENT GRM-2

Supply/Demand Balance (MMBtu)

	Capacity	
Long Haul Transportation		
PNGTS	1,000	
Iroquois	4,000	
Niagara	3,122	
Tennessee Gulf		
FT-A 1	24,777	
FT-A 2	25,223	
FT-A 3	21,596	
Total	79,718	
Underground Storage		
Total	28,115	
Supplemental Facilities		
AES	15,000	
DOMAC		
Vapor	0	
Liquid	0	
LNG from Storage	22,800	
Propane		
Vapor	34,600	
Truck	0	
Total	72,400	
Grand Total	180,233	
	Demand w/o DSM	Demand w/ DSM
Design-Day-2014/15	148,866	141,813
Design-Day-2010/11	140,043	137,326
Excess-2014/15	31,367	38,420
Excess-2010/11	40,190	42,907
% Excess -2014/15	21.07%	27.09%
% Excess -2010/11	28.70%	31.24%

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-041

National Grid NH's Responses to
Staff's Data Requests – Set #1

Date Received: May 21, 2010 | Date of Response: June 14, 2010
Request No.: Staff 1-49 | Witness: Theodore Poe, Jr.

REQUEST: At the May 20, 2010 technical session, Staff provided to the company a listing of ENGI's supply resources along with their peak day capacities on a primary firm basis. Please state whether the Company agrees with the individual quantities listed under the column headed Chart IV-C-2 and with the grand total of 179,537 MMBtu/day. If not, please explain why and provide the correct quantities.

RESPONSE: Please refer to the attachment to this response. On the left-hand side, the Company has replicated the format and data of the listing provided to the Company at the May 20, 2010 technical session. On the right-hand side, the Company has listed and annotated with references its peak-day deliverability as well as its forecasted design day requirements paralleling the Staff's format.

**ENGI
Design Day Resources**

	Appendix D	Chart IV-C-2
Long Haul		
PNGTS	354	354
Iroquois	4000	4000
—		
Niagara	3122	3122
Tennessee Gulf		
FT-A 1	24777	25407
FT-A 2	25223	30000
FT-A 3	21596	20000
Total	79072	82883
Underground Storage		
Dominion		934
Honeoye		1957
Nat Fuel		6098
FS-MA		15265
—		
Total	28115	24254
—		
Supplemental		
AES	0	15000
DOMAC		
Vapor	0	0
Liquid	4000	22800
LNG From Storage	9397	0
Propane		
Vapor	32282	34600
Truck	5607	0
Total	51286	72400
Grand Total	158473	179537
Design Day-2014/15		158473
Design Day-2010/11		149650
Excess-2014/15		21064
Excess-2010/11		29887
% Excess -2014/15		13.29%
% Excess-2010/11		19.97%

**ENGI Contractual Rights to City-Gate
Deliverability on Design Day (MMBtu)**

	Company's Response		
Long Haul			
PNGTS 1999-01	1,000	<—	Chart IV-C-2; Page 1 of 4; PNGTS City Gate MDQ
Iroquois			
ANE	4,000	<—	Chart IV-C-2; Page 1 of 4; TGP #33371 (ANE) City Gate MDQ
Niagara	3,122	<—	Chart IV-C-2; Page 1 of 4; TGP #2302 (Niagara) City Gate MDQ
Tennessee			
FT-A From Gulf	21,596	<—	Chart IV-C-1; TGP contract #8587 less the Zone 4 component
FT-A From Dracut	20,000	<—	Chart IV-C-2; Page 1 of 4; TGP #42076 (Dracut) City Gate MDQ
FT-A From Dracut	30,000	<—	Chart IV-C-2; Page 1 of 4; TGP #72694 (Dracut) City Gate MDQ
Total	79,718		
Underground Storage			
Dominion			
Honeoye			
Nat Fuel			
FS-MA			
TGP Zones 4 and 5	28,115	<—	Chart IV-C-1; TGP contracts #632 plus #11234 plus the Zone 4 component of #8587
Total	28,115		
Interstate Subtotal	107,833		
Supplemental			
AES	15,000	<—	Chart IV-C-2; Page 4 of 4; Granite Ridge Energy LLC MDCQ
DOMAC			
Vapor	0		
Liquid	0		
LNG From Storage	22,800	<—	Chart IV-C-2; Page 4 of 4; Max Vaporization (LNG): Concord+Tilton+Manchester
Propane			
Vapor	34,600	<—	Chart IV-C-2; Page 4 of 4; Max Vaporization (Propane): Nashua+Tilton+Manchester
Truck	0		
Total	72,400		
Grand Total	180,233		
Design Day-2014/15	148,866	<—	Appendix D; Page 8 of 87; 'Firm Sendout' line under 'Peak Day' column
Design Day-2010/11	140,043	<—	Appendix D; Page 4 of 87; 'Firm Sendout' line under 'Peak Day' column
Excess-2014/15	31,367		
Excess-2010/11	40,190		
% Excess -2014/15	17%		
% Excess-2010/11	22%		

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-041

National Grid NH's Responses to
Staff's Data Requests – Set #1

Date Received: May 21, 2010 | Date of Response: June 14, 2010
Request No.: Staff 1-50 | Witness: Theodore Poe, Jr.

REQUEST: If the Company agrees that it currently has under contract primary firm capacity totaling 179,537 MMBtu/day, does it also agree that this is 21,064 MMBtu/day greater than the projected design day demand in the final year of the forecast period? If not, please explain. If yes, what consideration has the Company given to eliminating this excess by not renewing one or more of its expiring contracts?

RESPONSE: Referring to the attachment to the Company's response to Staff 1-49, the Company has total peak day deliverability of 180,233 MMBtu/day. The forecasted peak day requirement in the final year of the forecast period is 148,866 MMBtus (Base Case Design Year 2014-15: No DSM: Appendix D, Page 8 of 87). Assuming all contracts are renewed at the current levels and pricing relationship remain constant throughout the forecast period, in the final year of the forecast (2014/15), the peak day deliverability exceeds the peak day forecast by 31,367 MMBtus. As listed in the forecast results for the 2014/15 design day (Appendix D, Page 8 of 87), the excess occurs in the three supplies: Granite Ridge ('AES') supply sharing, LNG and propane. At this time, these supplies represent the highest variable costs. Since the Company has just completed the contracting for its latest incremental Tennessee capacity ('Concord Lateral'), there will be some excess in the portfolio as the Company grows into the new capacity. Until transportation contracts come up for renewal, the Company will continue to optimize these contracts to extract additional value from them and reduce the cost to its customers. Throughout the forecast period, as contracts expire or come up for renewal, the Company will consider each asset and its contribution to the portfolio and determine whether to renew, replace or terminate the respective agreement.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-041

National Grid NH's Responses to
Staff's Data Requests – Set #1

Supplemental Response

Date Received: May 21, 2010 | Date of Supplemental Response: July 2, 2010
Request No.: Staff 1-50 | Witness: Theodore Poe, Jr.

REQUEST: If the Company agrees that it currently has under contract primary firm capacity totaling 179,537 MMBtu/day, does it also agree that this is 21,064 MMBtu/day greater than the projected design day demand in the final year of the forecast period? If not, please explain. If yes, what consideration has the Company given to eliminating this excess by not renewing one or more of its expiring contracts?

SUPPLEMENTAL RESPONSE:

During the forecast period, existing resources in the Company's portfolio that are set to expire or come up for renewal are listed in the table below (provided as Table IV-C-3 in the Company's filing):

Contract	MDCQ	Annual Quantity (MMBtu)	Date of Expiration
Granite Ridge Energy, LLC	15,000	450,000	***9/30/2012 (Corrected)***
BP Canada Energy Company	3,199	1,167,635	3/31/12
BP Canada Energy Company	4,047	1,477,155	03/31/2010
Chevron Natural Gas	21,596	3,908,876	04/30/2010
Repsol Energy North America Corporation	42,500	7,607,500	10/31/2010
Distrigas of Massachusetts Corporation FLS160		100,000	10/31/10
Sempra Energy Trading	7,500	907,500	03/31/2010
Honeoye Storage Corporation	1,957	245,280	04/01/11Evergreen
National Fuel Company N02358	6,098	2,225,770	3/31/11 Evergreen

Contract	MDCQ	Annual Quantity (MMBtu)	Date of Expiration
National Fuel Company O02357	6,098	670,800	3/31/11 Evergreen
Tennessee Gas 523	21,844	1,560,391	10/31/2015
Tennessee Gas 632	15,265	5,571,725	10/31/2015
Tennessee Gas 2302	3,122	1,139,530	10/31/2015
Tennessee Gas 8587	25,407	9,273,555	10/31/2015
Tennessee Gas 11234	9,039	3,299,235	10/31/2015
Tennessee Gas 33371	4,000	1,460,000	10/31/2011
Tennessee Gas 42076	20,000	7,300,000	10/31/2015

As each of these contracts expire or come up for renewal, the Company will follow its planning process as described in the Company's filing. The Company will evaluate the need to maintain each contract as part of the resource portfolio. As part of this need analysis, the Company will consider the trends in transportation migration and the growth in transportation relating to new customers that have not previously been served by the Company, and therefore, are not subject to the assignment of capacity. Depending on the type of need, the Company will canvas the marketplace to determine the availability of a replacement resource with consideration being given to demand–side resource options. Where appropriate, the Company will solicit competitive bids to determine the lowest-cost available resource. Finally, the Company will evaluate non-price factors associated with the available replacement options such as flexibility, diversity, reliability and contract term to determine the least-cost, most reliable option to meet the Company's resource need. This same approach will be implemented when the need arises for a new resource to be added to the portfolio. It is too early at this time to pin-point the exact modifications the Company will look to implement in the last year of the forecast period, but should all factors remain constant, the Company will seek the optimal balance of the resource portfolio to meet customer requirements in a least-cost, reliable manner.

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-041

National Grid NH's Responses to
Staff's Data Requests – Set #1

Supplemental Response

Date Received: May 17, 2010 Date of Supplemental Response: July 2, 2010
Request No.: Staff 1-35 Witness: Theodore Poe, Jr.

REQUEST: Ref. IV-8. Specify, by demand-side resource and by year, the demand-side management costs included in the SENDOUT model under the resource mix mode. Also provide on the same basis the projected MMBtu savings and number of participating customers.

SUPPLEMENTAL RESPONSE:

In its initial response to Staff 1-35, the Company inadvertently indicated that resultant MMBtu savings for the resource mix analysis were to be found in Chart IV-D-11. However, Chart IV-D-11 contains the MMBtu savings for the High-Case DSM scenario. There was no summary MMBtu savings chart presented in the Company's filing regarding the resource mix analysis optimizing DSM and traditional gas resources along with the conversion of a portion of the Company's Tennessee long-haul capacity to short-haul from the Marcellus Basin. However, the detailed scenario information was included in Appendix D (Page 76 through Page 81).

Demand-side management cost savings are not found in the filing since there was no resource mix scenario without DSM to calculate comparable costs. That being said, the Company has prepared a comparable run of its Base Case Demand – Design Year excluding the availability of DSM measures, in order to be responsive to Staff. (See Attachment Staff 1-35 (Supp.))

Reduction in Total Resource Costs
Base Case Design Year
Resource Mix Scenario without DSM vs. Resource Mix Scenario with DSM

Resource Mix Scenario without DSM	2010/11	2011/12	2012/13	2013/14	2014/15
Total Gas Resource Cost	$116,033,464	$123,998,279	$127,339,390	$130,922,420	$134,513,641
Total DSM Cost	$0	$0	$0	$0	$0
Total Resource Cost	$116,033,464	$123,998,279	$127,339,390	$130,922,420	$134,513,641
Total Gas Customer Requirements (MMBtu)	14,149,800	14,608,800	14,905,000	15,265,200	15,625,300
Total DSM Customer Requirements (MMBtu)	0	0	0	0	0
Total Annual Customer Requirements (MMBtu)	14,149,800	14,608,800	14,905,000	15,265,200	15,625,300
Average System Cost ($/MMBtu)	$8.2004	$8.4879	$8.5434	$8.5765	$8.6087

Resource Mix Scenario with DSM	2010/11	2011/12	2012/13	2013/14	2014/15
Total Gas Resource Cost	$113,738,170	$120,425,264	$121,730,814	$123,987,499	$126,244,940
Total DSM Cost	$395,557	$888,583	$1,923,808	$1,923,808	$1,923,808
Total Resource Cost	$114,133,727	$121,313,847	$123,654,622	$125,911,307	$128,168,748
Total Gas Customer Requirements (MMBtu)	13,881,700	14,224,700	14,304,300	14,535,800	14,767,200
Total DSM Customer Requirements (MMBtu)	268,100	384,100	600,700	729,400	858,100
Total Annual Customer Requirements (MMBtu)	14,149,800	14,608,800	14,905,000	15,265,200	15,625,300
Average System Cost ($/MMBtu)	$8.0661	$8.3042	$8.2962	$8.2483	$8.2026

DSM Reduction in Requirements (BBtu)					
Program 1 - Residential - 2009	30.200	30.300	30.200	30.200	30.200
Program 1 - C&I - 2009	53.600	53.900	53.600	53.600	53.600
Program 2 - Residential - 2010	30.200	30.300	30.200	30.200	30.200
Program 2 - C&I - 2010	53.600	53.900	53.600	53.600	53.600
Program 2 - Residential - 2010 (Incremental)	21.300	21.400	21.300	21.300	21.300
Program 2 - C&I - 2010 (Incremental)	25.600	25.700	25.600	25.600	25.600
Tier1 - Residential	0.000	60.700	90.500	120.600	150.800
Tier1 - C&I	53.600	107.800	160.900	214.600	268.200
Tier2 - Residential	0.000	0.000	63.900	85.200	106.500
Tier2 - C&I	0.000	0.000	0.000	0.000	0.000
Tier3 - Residential	0.000	0.000	22.800	30.400	38.000
Tier3 - C&I	0.000	0.000	48.000	64.000	80.000
Total	268.100	384.000	600.600	729.300	858.000
DSM Cost Savings By Program					
Program 1 - Residential - 2009	$213,995	$211,818	$185,281	$207,508	$223,328
Program 1 - C&I - 2009	$379,806	$376,799	$328,844	$368,292	$396,371
Program 2 - Residential - 2010	$213,995	$211,818	$185,281	$207,508	$223,328
Program 2 - C&I - 2010	$379,806	$376,799	$328,844	$368,292	$396,371
Program 2 - Residential - 2010 (Incremental)	$150,930	$149,601	$130,679	$146,355	$157,513
Program 2 - C&I - 2010 (Incremental)	$181,400	$179,661	$157,060	$175,901	$189,311
Tier1 - Residential	$0	$424,336	$555,231	$828,658	$1,115,163
Tier1 - C&I	$379,806	$753,598	$987,145	$1,474,544	$1,983,334
Tier2 - Residential	$0	$0	$392,036	$585,420	$787,565
Tier2 - C&I	$0	$0	$0	$0	$0
Tier3 - Residential	$0	$0	$139,881	$208,882	$281,009
Tier3 - C&I	$0	$0	$294,487	$439,752	$591,598
Total	$1,899,737	$2,684,432	$3,684,768	$5,011,113	$6,344,893

ENERGYNORTH NATURAL GAS, INC.
d/b/a NATIONAL GRID NH
DG 10-041

National Grid NH's Responses to
Staff's Data Requests – Set #4

Date Received: August 31, 2010 Date of Response: September 13, 2010
Request No.: Staff 4-4 Witness: Theodore Poe, Jr.

REQUEST: Ref. Response to Staff 3-16. In response to a question asking whether the demand-side resource tiers can be dispatched more than once by the SENDOUT model in the resource mix mode, the Company said that "because of limitations in SENDOUT the Company is not able to respond to this question." Regardless, was it the Company's intention that the model dispatch each tier multiple times assuming it was economic to do so?

RESPONSE: No, it was not the Company's intention that the model dispatch each tier multiple times. The documented functionality of the SENDOUT model indicated that the user could not dispatch a DSM tier multiple times. It was dependent on the Company to specify the maximum load reduction and the concomitant cost of each DSM tier. Doing so, the Company avoided extrapolating linear pricing for increases in DSM which may in fact be non-linear.

Guide material 192.703 General

View Code

1 GENERAL

Any time a pipeline is found to be damaged or deteriorated to the extent that its serviceability is impaired or leakage constituting a hazard is evident, immediate temporary measures should be employed to protect the public and property. If it is not feasible to make a permanent repair at the time of discovery, then as soon as feasible, permanent repairs should be made.

2 REPAIR OF PIPE

2.1 General.

Prior to repairing a pipeline, the operator should consider the operating conditions, design, and maintenance history, as necessary, to ensure that repair actions do not further damage the pipe. Where warranted, the operating pressure should be lowered, pipe exposure should be limited, access to the area should be limited, personnel protection should be provided, and fire extinguishing equipment should be available.

2.2 Repairs to distribution lines.

Methods of permanent repair to non-thermoplastic distribution lines include the following.

(a) Cutting out as a cylinder and replacing the piece of damaged pipe.

(b) Applying a full-encirclement welded split sleeve of appropriate design.

(c) Applying a properly designed bolt-on type of leak clamp or sleeve.

(d) For steel pipe, applying a fillet-welded steel plate patch of similar material of equal or greater thickness, of appropriate grade, and with rounded corners.

2.3 Repairs to transmission lines.

For repairs to steel transmission lines, see §§192.711, 192.713, 192.715, 192.717, and 192.751. Section 192.485 allows the alternative of lowering the MAOP on corroded transmission pipe where a safe operating pressure can be calculated based on the remaining strength of the corroded pipe. See guide material under §192.485.

2.4 Permanent repairs to thermoplastic piping.

Repair methods for thermoplastic piping include the following.

(a) Cutting out as a cylinder and replacing the piece of damaged pipe.

(b) Applying a properly designed bolt-on type saddle, leak clamp, or sleeve.

(c) Installing a repair sleeve meeting the requirements of ASTM D2513.

(d) See guide material under §192.311.

(e) For gas flow control during repair, see 5 of the guide material under §192.321.

2.5 Repair procedures.

The repair should be made in accordance with a qualified repair procedure.

2.6 Compression couplings in pipelines.

Repairs using compression couplings and repairs to pipelines that may contain compression couplings should consider the following.

(a) Coupled pipe is subject to pullout near bends, near the end of the pipeline, at temporary end closures, while performing stoppering or stopping procedures, when the pipeline is severed, and while long sections of pipeline are exposed.

(b) Some factors that can contribute to pullout potential are the pipe diameter, material, and surface; operating pressure; temperature changes; buoyancy; and soil moisture, compaction, and type.

(c) The procedure for safely repairing the pipeline should include consideration of the following precautionary, preventive, and mitigating actions.

(1) Reviewing maps and records to determine if couplings exist.

(2) Reviewing manufacturer's recommendation for installing and maintaining compression couplings.

(3) Analyzing each project for the potential of coupling pullout, including pullouts on adjacent line sections.

(4) Performing an electrical continuity test to check for indications of unknown insulating couplings.

(5) Reviewing contingency procedures to be used in the event of a pullout.

(6) Reducing pressure prior to excavation.

(7) Installing anchors sufficient to resist anticipated pullout forces in the pipeline.

(8) Reinforcing known couplings.

(9) Minimizing the length of exposed pipe during the repair work.

(10) Backfilling offset replacement piping before severing the pipeline.

(11) Providing a separate excavation for pressure control operations to prevent injury from pullout of an unknown coupling.

(12) Designing and installing protective sleeves or bridging when making mechanical joints that either connect plastic piping or plastic piping to steel piping. This is especially true for PE pipe manufactured prior to 1982, since some is known to be susceptible to premature brittle-like failures. Also, attention should be given to any recommendations by the pipe manufacturer. For protective sleeves, see guide material under §192.367.

2.7 Inspection and testing.

(a) All repairs to distribution lines should be visually inspected and leak tested at operating pressure.

(b) All repairs to transmission lines should be tested in accordance with §192.719.

3 CONSIDERATIONS FOR REPLACEMENT OR RENEWAL

3.1 All pipelines.

A guide to assist an operator in developing a method of evaluating the serviceability and need for replacement or renewal of existing pipelines is AGA XL8920, "Attention Prioritizing and Pipe Replacement/Renewal Decisions."

3.2 Cast iron pipe.

See Guide Material Appendix G-192-18.

4 REALIGNMENT OF PIPING

4.1 Steel.

(a) General.

Prior to realigning (moving in any direction) piping, the operator should establish a procedure for determining the feasibility of safely realigning the piping and performing the work. A useful reference for developing such a procedure is PRCI L51717, "Pipeline In-Service Relocation Engineering Manual."

(1) *Feasibility analysis*. The procedure for determining the feasibility of safely realigning the pipe should include consideration of the following.

(i) Determining the amount of realignment required.

(ii) Reviewing the operating history of the involved section, such as records of leaks, damage, and external and internal corrosion.

(iii) Reviewing the material properties of the pipe and associated valves and fittings, such as specification, rating or grade, wall thickness, SMYS, toughness, and seam and joint characteristics.

(iv) Performing a new stress analysis, reviewing relevant prior stress analyses and safe practices established by prior projects.

(v) Determining the maximum safe operating pressure during the realignment.

(vi) When the feasibility analysis indicates a potentially unsafe condition may be caused by moving the pipe under normal operating conditions, consideration should be given to isolating the line segment, lowering the pressure in the segment, depressuring the segment, or other appropriate action.

(2) *Performance of the work*. The procedure for performing the work should include consideration of the following.

(i) Training and qualification of personnel for the realignment procedure.

(ii) Monitoring the pressure during the realignment to ensure that the maximum safe operating pressure is not exceeded.

(iii) Providing for shutdown and purging of the piping if necessary.

(iv) Minimizing employee and public exposure at the work site.

(v) Potential adverse effects of weather conditions, ground and surface water, and bank stability.

(vi) External inspection of the exposed pipe for variation from the feasibility study and for visible defects, such as dents, gouges, grooves, arc burns, corrosion, and coating damage.

(vii) Making appropriate repairs.

(viii) Full control by the operator of the actual realignment process.

(ix) The adequacy of pipe supports to prevent unintended movement.

(x) Ditch padding and backfill materials to prevent damage to the pipe and coating.

(xi) Backfill and compaction procedures to prevent additional movement due to settlement after realignment.

(b) Additional considerations for compression-coupled piping.

(1) *Feasibility analysis.* The procedure for determining the feasibility of safely realigning the piping should also include consideration of the following.

(i) Reviewing the manufacturers' recommendations for installing and maintaining compression couplings.

(ii) Analyzing each project for the potential of coupling pullout, including pullouts on line

(ii) Analyzing each project for the potential of coupling pullout, including pullouts on line sections connected to each side of the project piping.

(iii) Installing anchors to resist unbalanced forces on each side of the project piping.

(iv) Reinforcing all involved couplings prior to actually realigning the pipe.

(2) *Performance of the work.* The procedure for performing the work should also include consideration of the following.

(i) Reducing pressure prior to excavating, reinforcing, and realigning.

(ii) Minimizing excavation during the locating and reinforcing activities.

(c) References.

(1) PRCI L51717, "Pipeline In-Service Relocation Engineering Manual," (PR218-9308).

(2) API RP 1117, "Movement of In-Service Pipelines."

4.2 Cast iron.

Realignment of cast iron pipe is not recommended. See Guide Material Appendix G-192-18.

4.3 Plastic.

Realignment of plastic pipe is not recommended except where replacement is not feasible. If realignment is necessary, then the following should be considered.

(a) General.

See 4.1 (a) and (b) above.

(b) Additional considerations.

(1) Damaged sections should be replaced.

(2) Recommendations of pipe and fitting manufacturers should be reviewed in determining the allowable pipe movement and joint deflection.

(3) To minimize or avoid stress concentration at joints during and after realignment, the operator should:

(i) Consider the effect of thermal stresses.

(ii) Provide continuous pipe support (e.g., bridging, protective sleeves, ditch grading, and proper backfill) to prevent movement from settlement after realignment. For protective sleeves, see guide material under §192.367.

(iii) Review records to determine the type of plastic material used in manufacturing the pipe. Thermosetting plastics (e.g., fiberglass reinforced epoxy composite pipe) and some thermoplastics (e.g., ABS and PVC) allow only marginal flexing of joints without damage.

(iv) During PE piping relocation, minimum bend radius recommendations should be observed to avoid overstressing joints at fittings in PE piping, which can lead to premature failures. For bend radius recommendations, see guide material under §192.367
.

(v) Review records to determine the types of fittings that may be involved. Some fittings provide little, if any, pullout resistance.

(4) Branch lines and service lines connected to the section to be realigned should be reviewed and replaced or extended as necessary. Extensions will usually be required to prevent imposed tensile stresses in the pipe material due to the realignment.

(5) Buried valves should be properly supported and aligned for correct operational orientation.

5 GAS LEAKAGE CONTROL GUIDELINES

Guide Material Appendix G-192-11 (Natural Gas Systems) and Guide Material Appendix G-192-11A (Petroleum Gas Systems) provide guidelines for the detection, classification, and control of gas leakage. These appendices include information related to the prompt repair of hazardous leaks.