STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 13-06-02 PURA INVESTIGATION OF CONNECTICUT'S LOCAL DISTRIBUTION COMPANIES' PROPOSED EXPANSION PLANS TO COMPLY WITH CONNECTICUT'S COMPREHENSIVE ENERGY STRATEGY

November 22, 2013

By the following Commissioners:

John W. Betkoski, III
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DECISION

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I. INTRODUCTION

A. Summary

In this Decision, the Public Utilities Regulatory Authorityapproves, with modifications, a regulatory model for the Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, and Yankee Gas Services Company, which will allow the companies tocarry out a large-scale natural gas expansion plan, pursuant to the Governor's 2013 Comprehensive Energy Strategy for Connecticut. Specifically, the Authority approves anew Hurdle Rate Model with modifications, establishes new rate and recovery mechanisms and institutes an annual reconciliation/reporting process to allow for more timely review and recovery of prudent expenditures related to natural gas expansion activity.

B. Background of the Proceeding

Section 51 of Public Act 13-298, An Act Concerning Implementation of Connecticut's Comprehensive Energy Strategy and Various Revisions to the Energy Statutes (Act), formerly H.B. 6360, requires in pertinent part:

> On or before June 15, 2013, the gas companies, as defined in section 16-1 of the general statutes, as amended by this act, shall jointly submit to the Commissioner of Energy and Environmental Protection and the Public Utilities Regulatory Authority a natural gas infrastructure expansion plan to provide natural gas service to on and off-main gas customers consistent with the goals of the 2013 Comprehensive Energy Strategy approved by the Commissioner of Energy and Environmental Protection in accordance with section 16a-3d of the general statutes as amended by this act . . .

Pursuant to the Act, theConnecticut Natural Gas Corporation (CNG), The Southern Connecticut Gas Company (Southern), and Yankee Gas Services Company(Yankee; collectively, Companies) filed a Joint Natural Gas Expansion Plan (Initial Plan) on June 14, 2013, with both the Commissioner of the Department of Energy and Environmental Protection's (DEEP) Bureau of Energy and Technology Policy (BETP) and the Public Utilities Regulatory Authority (Authority or PURA). The Commissioner of the DEEP was required, pursuant to Section 51(b) of the Act, to review and issue a preliminary determination as to whether the plan is consistent with the goals of the Comprehensive Energy Strategy (CES) no later than 30 days after submission. That determination was issued on July 17, 2013, whereby the BETP directed the Companies to make certain modifications and resubmit the changed portions of the Initial Plan to the Authority. On July 26, 2013, the Companies submitted the required modifications to the Initial Plan. Pursuant to Section 51(b) of the Act, the Authority has 120 days to review the Initial Plan, as modified by the Companies' joint July 26, 2013 letter to the BETP (Plan).

C. Conduct of the Proceeding

By Notice of Hearing dated August 15, 2013, pursuant to Section 51 of the Act, and §§16-11, 16-19kk, 16-19oo, 16-43 and 16a-3d of the General Statutes of Connecticut (Conn. Gen. Stat.), the Authority held a hearing on this matter on September 11, 2013, at its offices at 10 Franklin Square, New Britain, CT 06051. The Authority held further evidentiary hearing sessions on September 11, 12, 16, 17, 18, and October 2, 2013. The Authority closed the record on this matter by Notice of Close of Hearing dated October 21, 2013.

D. Parties &Intervenors

The Authority recognized the following as Parties to this proceeding: Connecticut Natural Gas Corporation, P.O. Box 1564, New Haven, CT 06506; The Southern Connecticut Gas Company, P.O. Box 1564, New Haven, CT 06506; Yankee Gas Services Company, P.O. Box 270, Hartford, CT 06141-0270; Office of Consumer Counsel, Ten Franklin Square, New Britain, CT 06051; Commissioner of the Department of Energy and Environmental Protection, 55 Elm Street, Hartford, CT 06106; and the Bureau of Energy and Technology Policy, Department of Energy and Environmental Protection, 10 Franklin Square, New Britain, CT 06051. The Authority recognized the following as Intervenors to this proceeding: the Office of the Attorney General; Connecticut Industrial Energy Consumers; and Environment Northeast.

E. Public Comment

In their comments provided on September 10, 2013, the Connecticut Energy Marketers Association (CEMA) and the Propane Gas Association of New England(PGANE)expressed concerns that the Plan places the heating oil and propane dealers at a further competitive disadvantage. First, the Companies' shareholders assume little to no risk in carrying out the Plan. Therefore, theCompanies will have no incentive to control costs and investment decisions they make on projects based on inaccurate forecasts of costs or consumption that will have no financial impact on the Companies. Second, the 30% premium the Companies propose to levy on new customers is insufficient to cover their costs.The remaining costs would have to be picked up by existing customers, further distorting the competitive market. In addition to the larger trade organizations, smaller fuel oil dealers expressed similar concerns.

Several Connecticut municipalities submitted letters in support of the Plan, including Darien, East Hampton, Ellington, Ledyard, Stamford, and Wilton. Town officials stated that they had received numerous calls asking why natural gas is not available in their area. Many have tried to work with the Companies to bring gas to their communities, to no avail. See, for example, correspondence dated September 24, 2013 from the City of Stamford.

The Competitive Natural Gas Suppliers urged the Authority to be mindful that no actions are undertaken in the instant proceeding that may adversely affect or undermine the competitive market. Further, they recommended that the Authority establish a separate proceeding to examine the current competitive market. See, correspondence dated October 1, 2013 from Santa Buckley Energy.

The Connecticut Business &Industry Association (CBIA), in its comments, stated that Connecticut's business climate is challenged, specifically with regard to the high cost of energy in our state. One contributing factor is that Connecticut is located at the "end of the pipeline" when it comes to obtaining traditional energy sources.We are disadvantaged in our ability to provide clean and affordable natural gas to homes and businesses due to transmission and distribution capacity limitations. See, correspondence dated October 8, 2013 from CBIA. Connecticut Construction Industry Association (CCIA) also submitted comments indicating its support for the Plan.See, correspondence dated October 7, 2013from CCIA.

One individual raised the question as to whether an environmental impact study was required pursuant to Conn. Gen. Stat. §22a-1a(b)(7). See, correspondence dated October 15, 2013from Charles Banfield. On October 31, 2013, the Authority requested public comments on this matter. Both commenters indicated that no such study was required by the Authority. See, written comments dated November 5, 2013 from the BETP and the Companies.

F. PROPOSED JOINT NATURAL GAS EXPANSION PLAN

The Plan aims to convert approximately 280,000 customers in total to natural gas over a 10-year period. Plan, p. 15. CNG and Southern proposed to convert 29,500 low-use (non-heating) customers to heating, add 113,700 new on-main customers and 54,000 new off-main customers by 2023. Plan, pp. 27-31. Yankeeproposed to convert 10,000 low-use customers to heating, add 41,296 new on-maincustomers and 31,125 off-main customers by 2023. Plan, pp. 55-58.

The Plan included what the Companiescall an "enhanced regulatory model" comprised of a new Hurdle Rate[1] model designed with a 25-year payback period, no requirement to run a Hurdle Rate test for customers that are located less than 150' from an existing main, and a "portfolio view" approach to Hurdle Rate modeling projects in a common geographical area. The portfolio view approachincludes three to five years of forecasted revenues in the Hurdle Rate analysis to capture anticipated customer conversions not initially supported by firm commitments at the time of signing, and an adjustment to the imputed revenues in the Hurdle Rate model to account for "societal benefits" of limited expansion projects.

The Companies' proposal for recovering the costs of the Plan has three primary components:

[1] The Hurdle Rate model is a net present value calculation the Companies' use to determine whether installing a service line or main extension for a customer or set of customers will be an economical investment over a given timeframe.

1. A Shared Savings Rate (SSR) for all “new” customers (those added after January 1, 2014). The SSR would include a surcharge of 30% on current distribution rates. Yankee proposed to charge both new off-main and on-main customers this same premium rate. CNG and Southern proposed to charge this premium rate only to new off-main customers. All three companies propose that new, premium-rate customers commencing gas service during the Plan remain on that rate for seven years. They would then switch to standard rates for their classes of service.

2. Sharing Non-Firm Margin (NFM) credits:

   a) Assign at least half of the NFM credit to offset the rate base of eachcompany;
   b) Assign the lesser of (i) an amount equal to one half of the NFM credit, or (ii) an amount equal to $15 million dollars from the NFM credit annually for all gas companies in the aggregate, apportioned to each gas company in proportion to revenues of and the existing and new capacity contracted for by each gas company. This assignment would offset expansion costs, including, but not limited to, the costs of adding new state, municipal, commercial and industrial customers where such additions provide societal benefits, including, but not limited to, increased or retained employment, local economic development, environmental benefits and transit-oriented development goals.

3. Should revenues from the SSR and the NFM credits not prove sufficient to cover the revenue requirements, the Companies proposed a System Expansion Rate (SER). Existing customers would pay the SER, allocated among customer classes pursuant to the approved cost-of-service studies in their last rate cases. CNG proposed to charge new on-main customers the SER rather than the SSR.Expansion Program customers would also pay this charge following expiration of their seven years on the SSR.

The Companiesalso seek authorization from the Authority to enter into long-term capacity agreements necessary to ensure adequate supply will be available to serve new natural gas customers they add while carrying out the Plan.Plan, pp. 15 and 16; pp. 110-112. The Companiespresented a summary of all of their requests for approval in the instant proceeding in Late Filed Exhibit No. 39. Consequently, the Authority is addressing these specific requests in this Decision and no other requests. The Authority’ssilence on a matter does not constitute approval.

II. AUTHORITY ANALYSIS

A. Objectives of the CES

Based on its assessment of current and future natural gas supplies, customer demand and costs of fuel oil and natural gas, the BETP directs the development of a seven-year natural gas expansion planning process. The goal of this plan would be to provide customers in Segment A (conversion prospects within 150’ of an existing main) and Segment B (cost-effective off-main conversion prospects) the choice of converting to natural gas quickly and efficiently. The BETP recognized that this program would require significant investment by the Companies, new and existing gas customers and private capital.

The BETP found that a large scale fuel-switching program fits within the state's energy, economic development and environmental policy.

> After weighing all of these risks and uncertainties, the BETP's analysis concludes that a large benefit will accrue to the state if it can effectively convert Segment A buildings and those Segment B buildings whose economics are most positive (i.e., the net benefits exceed the costs of investment).

CES, p. 138.

The BETP determined that a large scale-fuel switching program is in the interest of the state.The BETP also examined the current gas-line extension policies of the Connecticut utilities and proposed certain regulatory changes, together with a robust set of financing options. It foundthese proposals necessaryto carry out the objectives of the CES. The components of the CES's long range energy planning objectives related to natural gas are as follows:

1. Establish a planning process.
2. Raise customer awareness through marketing.
3. Financing mechanisms to make fuel switching more affordable and reduce upfront costs.
4. Incentives to assist systematic aggregation of new off-main customers.
5. Provide incentives to encourage installation of high-efficiency furnaces.
6. Change the Hurdle Rate calculation to reduce upfront customer charge for main extensions.
7. Alternative rate rider to pay customer main extension costs.
8. Allow greater flexibility when calculating customer's main extension costs.
9. Establish a mechanism for timely recovery of capital expenditures made by the gas companies.
10. Sharing of purchased gas adjustment credits.
11. Reduce the costs of equipment conversion and main extension.
12. Offer training/assistance programs to reduce economic dislocation.
13. Create options for customers who are unlikely to convert.

CES, pp. 146-156.

1. Public Act 13-298

The Act provided a statutory framework for the natural gas expansion plan proposed in the CES. It required thePlan to include, at a minimum, the following:

1. A customer conversion plan and schedule for a ten-year period.

2. An analysis demonstrating the feasibility of reaching the new customer conversion goals as directed by the Comprehensive Energy Strategy for on- and off-main customers.
3. A plan for outreach and marketing tailored to each customer segment.
4. A description of steps the gas companies will take to reduce the costs of conversion.
5. A strategy for capacity procurement.
6. A strategy for leveraging third-party investment to finance equipment replacement and main extensions for new customers.
7. A plan to harmonize natural gas infrastructure expansion with steps to reduce methane leakage from existing gas infrastructure.
8. A description of steps the gas companies will take to ensure that potential customers targeted for conversion to natural gas are incented to install efficient equipment and improve the efficiency of the building envelope at the time of conversion, provided such steps include, but are not limited to, providing such customers with information regarding the Home Energy Solutions audit, and to the extent feasible, an application form for said audit.
9. A proposal for rate changes consistent with the recommendations of the CES, including specific cost recovery mechanisms for each customer segment and a description of the rate impact of any proposed rate changes.

The Companiesproposed a detailed, comprehensive Plan to address the various requirementsunder the CES and theAct.

2. BETP Review

On July 16, 2013, the Energy and Technology Policy Bureau of the BETP issued a preliminary CES consistency review (BETP Review) of the Plan. In that review, the BETP found the Plan to be generally consistent with the goals of the CES, but not fully consistent. The BETP ordered the following modifications:

- The Plan must include greater detail on the worker training program to be consistent with the CES. The BETP recommended that the training program be open to displaced oil workers, and that those workers be encouraged to participate.
- The Plan must include more detail on proposed marketing strategies.
- TheCompaniesshould propose a time limited “credit” payment up to $250 to stimulate demand.
- Matching rebates should be offered by theCompanies and made available <u>only</u> for equipment that meets the same efficiency standards required for the Conservation and Load Management rebate programs for high efficiency gas furnaces and boilers.
- At the outset of the Plan, a company should be able to demonstrate that at least 60% of potential customers have committed to gas conversion before

construction commences, and forecasting of revenues should be limited to three years when determining the contribution-in-aid-of-construction (CIAC).

- The inclusion of societal benefits in the Hurdle Rate calculation should be limited to commercial, industrial and government customers that will add important societal benefits by converting to natural gas. The total value of the societal benefits should be no more than 20% of the total revenues of the project.
- If the Companies include a performance incentive proposal in the Plan, it must be conditioned on not only meeting the expansion goals, but also maintaining low rates and ensuring that customers install high efficiency furnaces and other “deeper” efficiency measures (such as insulation) at the time of conversion.
- The Plan should indicate the steps that will be taken to refer homes and businesses that are not located near a natural gas main to the Conservation and Load Management Programs.
- The Companies should establish an ongoing reporting system so they, the BETP, and the PURA can monitor the status of the gas expansion program on an ongoing basis and make adjustments as necessary. More appropriate triggers would be: a 50% reduction in the gas oil spread, 10% increase in distribution rates, and 20% less conversions than planned.

BETP Review, pp. 9 and 10.

The Companies were also directed to submit modifications to the Initial Plan within 10 days. The BETP indicated that the subsequent modifications the Companies made to the Plan were generally responsive to its concerns.However, the BETPobjected to some aspects of the Plan. Specifically, the BETP took exception tocustomer incentives for non-high efficiency equipment. Response to Interrogatory RA-23.

B. Regulatory Considerations

1. Conversion goals

The CES proposed as a goal “to make gas available to as many as 300,000 additional Connecticut homes and businesses. . . ” CES Executive Summary, p. V. The Plan’s stated goal is to convert approximately 280,000 new gas heating customers: 1) 39,500 current non-heating gas customers (primarily residential) with new incentives, availability of financing options, and targeted marketing efforts; 2) 155,000 on-main conversions (i.e., customers within 150 feet of an existing main) with changes to the Hurdle Rate model, plus incentives, financing options, and targeted marketing campaigns; and 3) 85,500 off-main conversions over the 10-year period driven by a rate design proposal outlined in the Plan. Plan, p. 3.

a. On-main Conversion Targets

The Plan aims to convert approximately 39,500 “low-use” customers and acquire 155,000 new “on-main” customers (within 150’ of an existing main). The Companiesstated that with the changes to the Hurdle Rate model, incentives/financing options and targeted marketing campaigns, they will be able to achieve their targets. Plan, p. 3.

Environment Northeast (ENE) recommended that the Authority require the Companies to prioritize and frontload the most cost-effective conversions in its initial years. Specifically, these are the “on main” additions that would likely require almost no capital investment by existing ratepayers. Brief, p. 2. The OCC recommended a similar approach. BachelderPFT, p. 37.

While the Authority has some concern with the Companies’ ability to achieve the total number of on-main potential customers identified in the CES, it encourages the Companies to pursue these types of conversions to the greatest extent possible, due to their cost-effectiveness and minimal customer acquisition barriers. However, the Authority will not place a specific requirement on the Companiesregarding prioritization of these customers.

b. Off-main Conversion Targets

The Companies are estimating that they will achieve 85,000 “off-main” customers during the 10-year period. Plan, Exhibits III-10 and IV-8. The Companies planning process for these off-main new customer additions will be divided into the following three major categories:

1. “Identified” main extension projects in its sales funnels at the start of the year.
2. “Neighborhood” projects that will primarily involve extending main to residential neighborhoods.
3. “Unknown” projects that will emerge later on through the course of the Plan.

Plan, pp. 59 and 60.

The Authority notes that the CES acknowledged that current forecasted market conditions greatly reduced the number of cost-effective off main conversion prospects. It recommended the Companies do their best to estimate the number of probable conversions over the next seven years. The BETP further recommended the Companies prioritize projects within Segment B with a focus on anchor-loads and concentrated residential areas and customers that provide wider economic benefits to the state to maximize the gas volumes and dollar savings on a given main extension. CES, pp. 144 and 145.

While the Companies appear to have taken steps to prioritize projects within the Segment B category, their overall plan to achieve approximately 85,000 new off-main customer additions appears to be a high goal. The Authority will closely monitor the Companies activity with regard to off-main customer line extensions.

c. Customer Definition

In this proceeding, theCompanies used different definitions of customer than what is typically used for ratemaking purposes. For ratemaking purposes, the Authority defines a customer as a meter. For purposes of the Plan, CNG and Southern defined customer as an end-user while Yankee used meters. Depending on what is being measured, this fact can be irrelevant or significant. Using a meter account, the Authoritycalculated and informed CNG and Southern at a hearing, that their customer counts would decrease 19% and 15%, respectively. The witness first indicated that “it’s the same amount of additions,” which the Authoritydisagrees. The witness also indicated that “the amount of the load is the same,” to which the Authority concurs. The witness went on to give the following example:

> If there's one apartment building out there, and there's 40 apartments, we counted it as 40. Under traditional kind of ratemaking counting, we would count that one meter as one customer. The amount of load is the same. Those 40 units are going to use the same whether you count it as one meter or if you count it as 40 units. . .

Tr. 10/2/13, pp.1502-1504.

While the amount of gas sold is the same, the difference in method of counting could be important when defining the level of success for the Plan. In the example given above, it is unknown who will receive some, all or none of the direct financial benefit from this conversion. There is no guarantee that the 40 tenants will see any monetary benefit from the conversion, unless their unit is metered for gas.

The Authority will direct the Companies to provide all new heating customer counts by both meter and end-user. Whether this nuance is important to any stakeholder can then be decided. However, the Authority will continue to require a count of metered customers for its purposes.

2. **Process Review / Cost Reduction Strategy**

The CES recommended that a cost reduction strategy be part of the natural gas expansion plan. CES, pp. 148, 154 and 155. Specifically, the BETP recommended thatthe Plan “. . . identify steps the gas companies will take or have taken to reduce the cost of conversion, such as neighborhood outreach efforts, organizing dedicated crews for main extension, streamlining permitting and siting compliance, etc.” The Plan addresses several actions planned or underway to meet this CES objective. Plan pp. 48-50 and 73-76.

While the Authority applauds the actions planned thus far, it finds that a more aggressive approach is needed to take advantage of the size and scope of this project. The Companies have the challenge of adding approximately 280,000 new customers in the next 10 years, on average approximately 28,000 a year; significantly greater than normal. An incremental 'business-as-usual' approach will only build upon the less than optimum existing processes and not maximize the potential opportunity at hand. A structured approach to identify the necessary steps of each major process can identify specific cost savings on repetitive processes, such as service installations, is critical to achieving break-through changes that significantly affect the overall project costs and customer rate impacts. Defining standardized consistent process approaches among the three Companies can effectively drive best practices, enhance measurement and comparison and maximize overall efficiency.

The Authority will direct the Companies to begin development of a process review approach (Process Review Approach), which could consist of a joint cross-sectional process team(s) that includes external members from relevant stakeholder groups (e.g., HVAC community, financing entities and/or Municipalities). This effort should be charged with a full review of the key processes within the context of this major expansion effort. The Process Review Approach would include:

- Clearly defining the processes to review – e.g., installation of a service line & meter or customer acquisition process.

- Map the 'as-built' / existing process and highlight individual utility differences if necessary. At the same time highlight/reference requirements if they exist (e.g., legislative requirements, regulatory order, municipal/permit mandates).

- Review in the field the accuracy of this 'as-built.'

- Evaluate each step in the process and address if it is essential to the actual process or an imposed control/requirement/mandate.

- Research alternative approaches (best practices) – industry practices, contractors, etc.

- Define new ideal processes – identify potential savings by eliminating inefficient steps.

- Pilot test the new processes and identify any necessary changes.

- If necessary review desired changes and benefits with the organization requiring the step (e.g., Legislature/Energy and Technology Committee, Regulatory, Municipality).

- Define method to collect meaningful data, to measure and monitor results.

- Identify communication and training approach within each organization and conduct.

Once the process is mapped, redefined and understood, it becomes easier to monitor progress and compare performance utility-to-utility, contractor-to-utility, contractor-to-contractor or municipality-to-municipality. If handled properly, fair comparisons can generate positive competition, which can benefits all stakeholders. Clear identification of the processes also leads to understanding of responsibilities for all aspects of the Plan.

3. Resource Adequacy

The Companies acknowledged that the large scope of the plan will require additional internal and external resources and that this is one of the reasons behind their recommendation to add three years to the Plan's originally proposed duration of seven years. Tr. 9/16/13, p. 845. The ability to secure and deploy these added resources were a matter of significant attention in the proceeding.

The Companies are presently examining how to meet the resource additions that they consider necessary, which include looking at recruitment, training, and certification programs in areas that include marketing, sales, construction, supervision, and safety. Companies' Brief, p. 20; Response to Interrogatory EN-21. They have also been meeting with contractors, state agencies, organized labor, and industry trade groups to address needs for external resources and report the existence of procurement plans to secure needed construction resources. Companies' July 26, 2013 letter to the BETP, pp. 2 and 3; Tr. 9/16/13, pp. 844 and 845; and Tr. 10/2/13, pp. 1484-1492.

The OCC cautioned that the availability of personnel resources threatens the pace at which the Companies proposed to conduct the Plan's activities. OCC Brief, pp. 23 and 24. The OCC cites the following factors to support this concern:

- CNG and Southern will increase installations of mains to serve new customers from 34 in 2014 to 48 in 2016, CNG and Southern Response to Interrogatory OCC-36 and Plan; Exhibit III-10.
- CNG and Southern proposed to increase off-main customer additions from 3,900 in 2014 to 5,600 in 2016. Id.
- Yankee proposed to increase off-main customers from 867 in 2014 to 2,272 in 2016. Plan, Exhibit. IV-3.

- CNG and Southern acknowledged: (a) the “potential risk that contractors will be unable to find sufficient qualified labor to carry out the construction activities required by the Plan,” and (b) installation contractor difficulty in locating trained and appropriately qualified utility labor and frustration in locating and skilled workers. CNG and Southern Response to Interrogatory OCC-80.

- CNG and Southern plan to double their crews from a 2014 level of 29 to 59 in 2019. CNG and Southern Response to Interrogatory OCC-46.

- The Companies face large numbers of potential retirements from among their internal workforces, with Yankee at 15% and CNG and Southern at 47% during the Plan’s first five years of implementation. Late Filed Exhibit No. 38.

The OCC stated that the need to supplement in-state labor sources with those from out-of state will diminish economic benefits to the state from the expansion and may increase labor rates. The OCC recommended that the Authority monitor resource availability to ensure that meeting plan goals do not compromise work safety or quality. To the extent that monitoring discloses a lack of sufficient numbers of skilled and appropriately qualified labor, the OCC recommended that Plan work be scaled back until such labor is trained and ready. OCC Brief, pp. 23 and 24.

The BETP addressed the issue of resource adequacy in its review of the original plan. The focus of its review related to development of in-state resources, which the BETP expected to perform the majority of Plan work. Commenting on the criticality of securing adequate personnel, the Plan discussed training in only general terms (e.g., without detailing the programs, dates, or goals). The BETP required the Companies to provide more details about the training required to provide sufficient resources to execute the Plan. BETP Review, p. 3.

The Authority shares the concerns expressed about the details of plans to ensure the availability of sufficient numbers of capable resources for the Plan’s execution. The Plan contemplates a vast expansion in the rate of Connecticut customer additions over the coming three to five years. This expansion is at the same time that many Northeast gas companies face what has been described to be major repair, replacement, and extension needs. Tr. 9/11/13, pp. 468–470.

TheCompanies plan to use contractors for field construction of mains and services. Yankee also anticipates using contractors for program engineering. Tr. 9/11/13, p. 492. When asked about the availability of these resources, company representatives spoke of their relationships with their contractors, and expressed confidence that contractors can effectively and timely respond to vastly increased requirements. Tr. 9/11/13, pp. 489–491. The only constraint that the Companies acknowledged in hearings was a possible limit on the number of qualified HVAC contractors available for converting customer equipment. The Companies reported programs for pre-qualifying HVAC contractors in an effort to facilitate the customer-conversion process. The Companies also added staff internally and report that they have been surprised at the number and quality of available candidates. Tr. 9/11/13, pp. 521–527, 492 and 493.

In response to the BETP'srequest for more detail on worker training programs, Yankee stated that "the Company is working closely with State agencies, organized labor and industry trade groups to help coordinate their efforts around the Plan's resource requirements." Companies' July 26, 2013 letter to the BETP. Yankee further stated that "coordination and cooperation among these diverse stakeholders is important and their input is pertinent to the successful development of the State's workforce". Yankee also stated that by mid-to-late October it will have a more fully developed plan relative to its crews. Tr. 9/11/13, p. 475.

Yankee's statements indicated confidence (qualitatively, rather than quantitatively) that engineering, project management, construction, quality assurance, and other human resource limitations will not comprise a barrier to meeting program expectations and goals.

The OCC also expressed concern about resource availability, citing three factors:

- The aggressive pace of the Plan.
- Competition with the cast-iron and bare-steel replacement programs in Connecticut.
- All of the Northeast states are in the midst of aggressive infrastructure replacement programs and adding new customers. They are all competing for skilled labor to install gas mains and services.

Bachelder PFT, p. 5.

The Authority believes a robust, analytically supported consideration of resource limitations is required to assure that planning can mitigate a number of risks. For example, these include: (a) competition with other programs, especially cast-iron and bare-steel replacement; (b) public safety if expansion impacts replacement activities; (c) schedule slippage; (d) cost escalation; and (e) quality assurance over work performed by stressed and, presumably in many cases, new resources.

Based on the above, the Authority will direct the Companiesto present a more detailed resource plan, incorporating, but not limited to the following items:

1. Plans for workforce training.
2. Plans for sequencing system-expansion activity in ways that minimize the strain on available resources:
   a. Focusing initially on connecting on-main and low-use customers.
   b. Concentrating marketing efforts for Expansion Plan in areas where cast-iron replacement is occurring, so that the programs do not compete.

3. Semi-annual reports addressing cost and schedule performance, and report on any resource-limits issues:
   a. These reports shall chart and explain plans versus results (including work accomplishments, resources estimated versus actually required, new resources acquired versus estimated) and explanations for variances.
   b. The reports shall include detailed reviews/audits of sample projects in the reports.

4. Annual cost projections for labor and material; these plans shall include past-year costs, future-year costs, and estimates for years 2 through 5 following.

5. Contracting/partnering arrangements with selected contractors:
   a. An on-the-job apprentice program to develop and employ skilled gas construction workers (with the assistance of governmental agencies).
   b. Agreements that seek to balance the risks/rewards associated with work flows that are likely to prove fluctuating and uncertain.

6. The Companies' current and planned work with the towns and cities to develop and implement a streamlined permitting system to reduce the permit time.

7. Standardized engineering designs for the more common types of construction such as new mains in urban streets, suburban streets, along sidewalk areas, which include typical service tie-ins and other normal fittings.

8. The number and caliber of construction inspectors to compensate for the newly trained gas workers; mandate that contractors institute their own quality-control group to evaluate their own employees and report the results to the gas company involved.

9. Plans to secure long-term fixed pricing for pipe and other materials to limit the amount of inflation and cost escalation on materials.

The Companies will be directed to report annually to the Authority regarding the efforts made, results obtained, effectiveness of, and potentially useful changes to the matters addressed above.

4. Financing Plan

The CES proposed two financing mechanisms which could be utilized for natural gas conversions. Those mechanisms include a low- or no-interest rate loan program for high efficiency heating and domestic hot water systems modeled on the "Mass Save" program. The second mechanism is an on-bill financing program that would enable customers to finance conversions on their utility bill over time. CES, p. 150.

Section 51(a) of the Act required the Plan to include "a strategy for leveraging third-party investment to finance equipment replacement and main extension costs for new customers." An additional statutory requirement, Section 117 of Public Act No. 13-247, An Act Implementing Provisions of the State Budget for the Biennium Ending

June 30, 2015 Concerning General Government (Budget Act), creates an on-bill financing program. It allows residential property owners to finance up to 90% of the cost of replacement of a heating system, as long as the equipment meets Energy Star ratings. Plan, p. 83.

The Companies proposed several financing tools. These tools include leveraging existing programs already offered by the Department of Economic and Community Development (DECD), the Connecticut Energy Efficiency Fundand the Clean Energy Finance and Investment Authority. These programs focus on conversions that involve the installation of high-efficiency furnaces, boilers and hot water heaters. Several of these programs include subsidies that allow a lower than market rate to be offered. Plan, p. 81.

The Companies developed a new program for a boiler/furnace replacement program pursuant to the Budget Act, and expect approval from the BETP by the end of October 2013. Under this program, participants can receive loans for up to $15,000 at up to 3% interest rate, as set by the financing program administrator. At the time of the hearings, the Companies were still in the process of selecting a third party administrator for the program. The Companies anticipate the program to run for three years at a net cost of approximately $8 to $23 million, depending on the number of participating customers, to be paid for by electric ratepayers through the system benefit charge. Plan, p. 83; Tr. 9/16/13, pp. 923-928.

Lastly, the Companies indicated they have or are in the process of developing new programs in partnership with financial institutions, such as the Peoples United Bank Home Heating Efficiency Conversion Loan program, Citizens Bank Efficiency Loan Program and an equipment leasing or loan receivable program with Altus Power Conversion and Partner RE. The Companies are also in discussions with Connecticut credit unions and other commercial banks to develop additional financing programs. Plan, pp. 84 and 85.

The OCC is concerned that the Companies' financing and rebate programs may not be robust enough to attract mid-to-low income customers. OCC Brief, p. 25. The OCC proposed that the Budget Act's loan program that requires electric ratepayers to subsidize residential furnace and boiler heating replacementbe structured in such a way as to limit the rate impact. The OCC further discussed the rate impact of a "mid-range" scenarioof approximately $1.02 monthly for The Connecticut Light and Power Company customers, $12.25 annually, and $2.57 monthly for The United Illuminating Company customers, $31 annually. Brief, p. 48; Late Filed Exhibit No. 29.

The Authority recognizes that many of the Plan's financing programs are still in the development/approval phase and as such, represent a "work in progress." The proposed portfolio of financing programs, when fully implemented, should be robust enough to enable the Companies to begin meeting their conversion goals. However, the portfolio of financing programs currently appears to be heavily dependent on ratepayer funding, rather than leveraging private capital. Of the four most important financing programs available in the 2014-2016 timeframe, only one program, the Smart-E Loan Program, is supported by private capital in combination with ratepayer funding.

Late Filed Exhibit No. 26.The Authority will direct the Companies to revisit their financing strategy periodically, including the ratio of ratepayer vs. private capital-funded financing dollars, through theProcess Review Approach discussed in II.B.2, Process Review / Cost Reduction Strategy. The enhanced financing strategy should be submitted to the Authority for approval. Improvements to this ratio could be a good basis on which to develop utility incentives.

While the Authority appreciates the OCC's recommendation regarding mitigating the potential rate impacts arising from the Budget Act's loan program, this recommendation is better directed to the BETP, who is statutorily charged with the review of the boiler/furnace replacement program, including a determination of the budget. The Authority will review the resulting charges from that program as part of the semi-annual systems benefit charge (SBC) filing.

5. Marketing Plan

The Companies presented their marketing efforts to encourage customer conversion under the Expansion Plan. Some of those efforts are in progress; others are in development.

The BETP requested more detail on the Companies' proposed marketing strategy. The BETP also observed that "the marketing plan should be data driven and results oriented. The Companies should develop specific, measurable and verifiable goals for the marketing plan." BETP Review, p. 4.

In response, the Companiesdiscussed leveraging the best practices of the marketing and sales process they developed. They described the marketing plans that they are developing, including possible areas of research to assist the Companies in tailoring strategies. These included testing messaging, media and other tactics to reach prospective customers. Marketing tactics will be tracked and those that fail to be cost effective will be discontinued.Companies' July 26, 2013 letter to the BETP, p. 6.

The Companies also discussed market research on customers who had converted over the past two or three years. This research included survey cards for new customers designed to help them understand why they had converted, their experience, and adapting their processes to improve the customer experience. Tr. 9/16/2013, pp. 994-997; Tr. 9/17/2013, pp. 1011-1018.

The Companies expressly requested approval of a limited "credit" payment up to $250 to stimulate demand as needed.The amount and timing of this credit will be planned to coincide with certain aspects such as town paving schedules, presence of the Companies' construction in the area (e.g., for replacement of older gas mains under the DIMP program), periods of reduced workload (e.g. in early spring when residential conversion demand is typically less), etc. This credit will be used to generate interest as needed and to generate cost savings from economies of scale gains as well as during the slower construction work period as a means to shave the peak workload of construction crews. The cost of the credit will easily be justified by the savings generated.Companies' July 26, 2013 letter to the BETP, p. 6.

The BETP stated that the qualitative descriptions provided by the Companies are suitable. However, the BETP requested quantified goals and objectives, and detailed tracking of progress in meeting them. BETP Review, 4. These goals and objectives are critical in assuring that a program of the massive dimensions and significant uncertainties applicable here gets implemented in a way that promotes efficient commitments of resources and maximization of desired results. The Companies will be directed to develop quantified marketing results goals, each of which sets forth a suitable range of outcomes, through a Process Review Approach as discussed in II.B.2, Process Review / Cost Reduction Strategy. Marketing plans tailored to each goal should be developed. The Companies should list the specific activities associated with each goal, and identify the resources, internal and external, required to conduct those activities. The Companies should also measure the effectiveness of those activities (e.g., customer awareness and understanding of offerings, customer perceptions of messaging effectiveness, reasons customers choose/reject offerings).

The record in this proceeding makes clear that much depends on what remains a reasonably, and to a large degree understandably, speculative view of customer behavior. A comprehensive and quantified set of goals and associated marketing plans will provide a sound baseline for beginning to measure actual reactions and behaviors. Regular reporting of progress against those goals and about the effectiveness of marketing activities will permit important adjustments to how and where expenditures are made under the program generally. More particularly, it will give important information about the market competitiveness of program offerings, and potential areas of customer resistance that may be addressed by better marketing.

The ENE recommended that the Authority require the Companies to make the expansion more energy efficient, such as stronger incentives for efficient equipment funded exclusively with shareholder capital. ENE Brief, p. 2. The Authority declines to make this ruling as it does not involve ratepayer funding.

The AG recommended that the Authority require the Companies toprovide to all customers considering conversion to natural gas pursuant to the Plan, a PURA-approvedconversion cost calculator. This handout would include a commodity cost differential calculator as well as a form for customers to get quotes from three vendors for each of the costs they could incur to convert to natural gas. AG Brief, p. 11. This form should also include a checklist of component costs of conversion, such as duct/piping changes, chimney lining, special venting and wiring, labor, permit costs and oil tank removal.The Authority agrees that a tool like this will assist customers in making a more informed decision on the full costs and benefits of conversion. The Authority will direct the Companiesto submit such a proposal for approval.

The Authority approves the use of a "credit" payment of up to $250, funded via the SER, which the Companies can use to stimulate demand as needed.The

Companies may be required to demonstrate that this credit was used to generate interest as needed and cost savings from economies of scale gains as well as utilized during the slower construction work period.The Authority will not restrict this credit payment to high-efficiency installations only due to the limited nature and the amount of this cash incentive.

6. Capacity Plan

The Companies requested authorization to enter into proposed long-term capacity agreements, which are referred to in the Plan as Precedent Agreements. The Companies further sought a ruling that the Precedent Agreements are appropriate and necessary to ensure adequate supply will be available to serve new natural gas customers. Late Filed Exhibit No. 39.The Companies updated their respective design-peak-day demand forecasts. Based on the anticipated customer growth, the Companies forecasted a requirement for additional peak day capacity as soon as the winter of 2014/2015. By the end of the expansion program, significantly more capacity would be required. Plan, pp. 86 and 95. The Authority notes that the CES observed that there will not be enough interstate pipeline, storage, or peaking capacity to serve a large-scale addition of new customers. Natural gas pipeline supply projects typically take 3 to 4 years to develop, meaning that capacity must be purchased based on projections of customer demand several years in the future. CES, p. 145.

The Companies requested that the Authority determine the agreements are appropriate and prudent and approve the capacity plan and proposed Precedent Agreements before December 1, 2013. The Plan stated that the capacity plan works with the existing diverse, reliable and low cost portfolios of supply, transportation, storage and peaking resources. The capacity agreements were jointly initiated, pursued, negotiated and finalized by theCompanies. Consequently, the agreements are identical except for the specific requirements of each respective gas company. Connecticut’s long standing gas reliability policy is consistent with many other jurisdictions and requires service reliability under all weather conditions and employs a design weather condition of the coldest day in 30 years. The qualifying type of capacity that is required to meet the reliability standard is primary firm non-recallable pipeline capacity, which is the highest priority of pipeline transportation contracts. The Companies testified that they maintain sufficient pipeline capacity to provide these design peak day services while retaining the inherent flexibility in their portfolios to manage its customer load profile, changes in market conditions and specific distribution system requirements. Plan, pp. 87 and 88.

The Companies testified that they develop their design-peak-day forecasts in similar fashion. Each one uses a load-factor analysis technique to develop per-customer peak-day requirements by customer class for typical customers. Those numbers are adjusted to reflect conservation initiatives, then multiplied by the numbers of customers in each class and added together, to determine total peak-day requirements of alltypical customers. Peak-day requirements for large customers are estimated individually, and then added to the typical-customers number to get total peak-day requirements. Tr. 9/12/13, pp. 607-616. The Companies provided year-by-year estimates of their large customer peak-day requirements through 2018. Response to Interrogatory EN-4. In addition, Yankee provided confidential estimates for five large customers' peak-day requirements for the same period. Response to Interrogatory EN-10 (protected).

The Companies jointly presented a plan to address the need for additional capacity to meet the proposed Plan. They provided confidential appendices to the Plan that presented their respective analyses to identify and compare alternative sources of supply capacity that could meet their requirements. Plan, Appendices 2A (CNG and Southern) and 2B (Yankee, protected). The capacity would be obtained from three sources:

- Long-term Precedent Agreements to purchase capacity from two pipeline expansion projects, the Tennessee Gas Pipeline (TGP) Connecticut Project, and the Algonquin Gas Transmission (AGT) AIM Project, both due to be in-service by November 1, 2016.
- Expansion of the daily output from existing liquefied natural gas (LNG) facilities connected to the CNG and Southern systems, which is anticipated to be in-service by November 1, 2016.
- Use of some existing capacity on the Iroquois Gas Transmission (Iroquois) system, which is anticipated to enter service on November 1, 2013.

Response to Interrogatory EN-8; Tr. 9/12/13, pp. 766-768.

The Companies presented evidence that, in addition to supporting the general customer-growth objectives of the CES and the Plan, address particular supply problems that have limited their ability to add customers in certain portions of their service territories. Expansion of the LNG plants connected to CNG and Southern systems can serve most parts of their service territory through displacement. Those expansions do not, by themselves, provide sufficient capacity to support the expansion-of-service objectives of the CES or the Plan. The pipeline-capacity additions provide additional capacity to particular gate stations on all three systems that are experiencing growth. Responses to Interrogatory EN-9 (protected). CNG and Southern need expanded capabilities that are part of the AGT expansion to expand their services to Glastonbury and Guilford, respectively. Yankee needs the TGP expansion to increase deliveries to Vernon, and the AGT expansion to provide increased service along the Montville Lateral (referred to by AGT as its E Lateral). Response to Interrogatory EN-5; Tr. 9/12/13, pp. 729-737 (protected).

The Companies' presentation of their capacity plan makes clear that the per-unit cost of the new capacity will be considerably higher than the per unit cost of their current capacity. The Companies are optimistic that the overall impact to customers will be relatively minor for several reasons, including access to new sources of supply, and the ability to mitigate capacity costs through secondary-market transactions, capacity releases and off-system sales. Plan, pp. 92 and 93.

The OCC stated that a necessary piece of the Companies' Plan is the purchase of pipeline capacity to support the load growth expected to be added over the course of the Plan. At current growth rates, without any incremental growth resulting from the Plan, the Companies need additional pipeline capacity. Until the new contracted pipeline capacity is in-service, the Companies are tight on deliverability capacity. The OCC recommended that: (i) the Authority should approve the execution of incremental pipeline capacity agreements as soon as possible to meet the ratification deadline for the pipeline agreements and not delay commencement of service; and (ii) all three Companies monitor their peak day growth carefully, particularly until new pipeline deliverability capacity arrives. If LNG facility upgrades to provide incremental deliverability can be moved forward on the calendar, the Companies should do so. Brief, p. 30.

The BETP determined that the Companies had provided an adequate plan to procure additional gas capacity to meet the expansion goals at a reasonable cost. The Companies' plan to acquire incremental pipeline capacity into Connecticut in support of the Plan's expansion goals should be approved. However, accomplishing the Companies' gas supply objective to ensure that gas continues to be fully reliable on their respective systems and is provided in an economic manner is not without challenges. This is particularly true as this region is recognized as the most pipeline capacity constrained area of the country. Brief, pp. 5, 10 and 11.

The Authority recognizes that managing gas capacity is a difficult and often uncertain undertaking. This is particularly true during the proposed gas expansion plan where there is the expectation that a large amount of new capacity will be needed over a relatively short period of time. In particular: opportunities for capacity additions do not typically coincide with the need for capacity; capacity additions are lumpy, not normally matching the need at the time; and forecasted demand for capacity may not materialize. As such, firm customer demand for capacity will necessarily chase the design day peak supply the Companies will have had to procure. These realities, among others, often cause the results of capacity additions to be suboptimal. The Companies have vast experience effectively managing their gas capacity portfolios and they should continue to do so through the gas expansion plan and beyond.

While the Authority does not presume to be able to effectively micro-manage the Companies' capacity purchasing strategies, it does offer the following observations. The incremental expansion projects selected by the three Companies only move gas from specific interconnections to their city gate stations and do not move gas from the upstream supply points to the interconnections associated with the selected projects. Based on this fact, the Companies have at least two options. The first option is that they could purchase additional capacity, if available, in their own name back to the supply source. The second option is that the Companies could purchase supply at the receipt points associated with the Precedent Agreements from firm shippers who can bring gas to specific interconnections/receipt points. Either of these options would increase the cost of incremental design peak day capacity to bring in Marcellus Shale gas. As to the commodity price, the Companies indicated that option two would result in a higher commodity price that would be above the actual Marcellus Shale cost of gas. Tr. 9/12/13, pp. 170-180.

During the protected portion of the Hearings, the Companies stated that they intend to purchase commodity at the respective delivery points shown in the Precedent Agreements from a supplier(s) of natural gas. The Companies expect to purchase commodity at these receipt points at a price that is higher than the posted Marcellus commodity prices. The testimony indicated that the receipt points associated with the Precedent Agreements have relatively few pipeline interconnects with Marcellus supply sources. Tr. 9/12/13, pp. 765-783.

The Authority notes that the receipt points for the respective Precedent Agreements may not be liquid supply point(s). Therefore, the price for which the Companies purchase their gas commodity at these receipt points could be impacted by changes in the supplies. Marcellus supplies have been priced lower than other supply sources. Any differential between the Companies total gas costs before and after the addition of the Marcellus supplies would offset increased pipeline demand charges. The Companies will not buy incremental suppliesat Marcellusprices, as the agreements are currently configured.. At this time, one of the receipt points shown in a Precedent Agreement does not have a direct interconnect with Marcellus supplies. The Companies would be dependent on future pipeline projects that would connect to the receipt point along with supplies that have been transported to that point. Capacity additions typically involve entering into long-term service contracts.

Regarding Yankee's protected response to Interrogatory EN-10, the Authority has concerns regarding the proposed addition of customers to Yankee's design peak day demand requirements listed in this response. As the information is protected, a specific discussion regarding the amount of peak day capacity that is needed for these customers cannot be adequately addressed in this Decision. The addition of these customers is a significant portion of the capacity Yankee proposes to procure. If any of these customers return to interruptible service or leave Yankee's distribution system, Yankee would have procured large volumes of design peak day capacity that would be unused and not paid for by these customers to meet its supplier of last resort obligation. The end result would be that ratepayers would have to cover the cost of this excess capacity. If Yankee seeks to procure firm capacity based in large part to its intent to provide firm service to thelarge customers it identified, the Authority will requirethat Yankee securefirm service contracts for a minimumofthreeyears with these customers to ensure that ratepayers are not left with the stranded cost of capacity should these customers decide to no longer take firm service.

The OCCis concerned about certain reliability issues. In particular, the possible consequences on the Companies' ability to meet their peak-day supply obligations from 1) equipment failure at an LNG plant, or 2) delay in completion of the AIM Project. The

Companies' addressed these concerns effectively. Tr. 9/12/13, pp. 784-814 (protected). The Authority shares the Companies' confidence that they will be able to deal with contingencies that arise.

The Companies' combined Written Exceptions (Comments) stated that the Precedent Agreements are necessary to meet the reliability standards associated with the Plan. The Comments raised an argument that the legislation requires that the Authority approve the proposed capacity. If any of the Companies were to exercise their "regulatory out" due to the Authority not approving the Precedent Agreements, the viability of the proposed pipeline capacity projects would be put in jeopardy."The aggregate cost commitment of the Precedent Agreements to the Companies over the fifteen year contract term is estimated to exceed $1 billion." Comments, p. 9, footnote 15.The Companies publicly releasedin their combined Comments confidential materialfrom the responses to Interrogatories OCC-41 and OCC-57related to the total cost of the capacity contracts.The OCC agreed with the Companies that the Authority should approve the Precedent Agreements. OCC Brief, p. 30. The BETP also agreed that the Precedent Agreements should be approved. The BETP arguedthat proposed capacity contracts, associated with the Precedent Agreements, provide the opportunity to obtain a more affordable, cleaner and secure energy future. The additional capacity into New England would lower fuel costs for heating, electric generation and industrial processes. The BEPT stated that "[d]uring the winter of 2012 – 2013,system constraints materially impacted electric ratepayers when heating needs created a shortage of gas supply for electric generation customer." BETP Brief, p. 20; Comments, p. 3.

The BETP's statement regarding the shortage of gas supply for electric generation in New England is included in the Comments and is not in the record of the instant proceeding. BETP Brief, p. 20. The Authority provided the following clarification to this statement. The Companies reserve primary firm capacity on the interstate pipelines from multiple supply sources to meet their firm customers design peak day demands. The design peak day is defined as the coldest day in the last 30 years. Electric generators typically have not purchased pipeline capacity to a supply source. The generators purchase commodity gas supply in the secondary interruptible market. This secondary interruptible market only exists when primary firm pipeline contracts are not fully required to meet firm customers daily demands. Since the interstate pipelines are designed to meet firm customers design peak day demands, no gas shortage occurred during the winter of 2012 / 2013 for firm customers in the New England market. The electrical generators simply made a conscious decision to purchase gas supply without primary firm peak day capacity. Consequently, the owners of the generators are susceptible to the price fluctuations and availability of commodity in the New England market.

The Plan included a considerable discussion of shale gas production, especially in the Marcellus producing region of western Pennsylvania and West Virginia. Plan, pp. 88, 96-98. The Authority expects that many new pipeline projects will enter service and have an impact on supply patterns, and thus on prices and basis differentials. Late

Filed Exhibit No. 22.The Authority reminds the Companies of their obligation to search out a combination of supplies from among all sources that provides the lowest cost of gas to their customers and is consistent with the Authority's reliability criteria discussed above.

The Authority finds that the $1 billion commitment by the Companies for the 15-year term of the capacity agreements produces a significant risk to ratepayers. Based on the total cost described in the Companies' Comments, the Authority calculated the combined annual increase in the cost of gas. Beginning in November 2016, it would cost all three Companies $67 million a year ($1 billion / 15 years) for the incremental pipeline demand charges. The Companies must pay the full cost of the annual demand charges that are necessary to reserve all contracted capacity beginning the year it enters service. Under current rulings, the Companies would offset the increased cost of gas to customers by using 99% of the annual NFMs. However, based on Section 51(d)(4) of the Act, most if not all of the NFMs will be allocated to offset rate base and those projects that have a societal benefit.

In regards to the Act's NFM allocation, the Authority notes the following. Unless the Companies combined NFMs are greater than $30 million there will be no dollars available to reduce the cost of gas. If the total combined NFMs are greater than $30 million,dollars would remain to reduce the cost of gas. For instance, if the Companies total combined NFMs are $40 million, 50% or $20 million would be allocated to offset rate base and the lesser of 50% of the remaining NFMs or $15 million would be allocated to offset projects with a societal benefit. Consequently, in this example, $5 million would remain to reduce the cost of gas. As a result, the total incremental impact of the new demand charges would be an increase in the cost of gas of $62 million ($67 million - $5 million). A portion of the incremental increase in the cost of gas would be offset by the addition of the new customers.

It is impossible for the Authority or the Companies to accurately project the future peak day demand or how much of the demand costs would be offset by new customer growth. Therefore, the firm ratepayers are at risk for all of the costs associated with the incremental capacity when it enters service in 2016. Under normal circumstances the Authority has not preapproved the purchase of incremental pipeline capacity contracts. Since the legislation requires the Companies to create an expansion plan of the magnitude discussed in this Decision, the Authority will approve the Precedent Agreements to make the expansion plan viable. However, a number of changes have been made to the expansion plan in this Decision that could increase or decrease the number of customers that the Companies will be able to serve over the next 10 years. Consequently, the annual design peak day demand associated with the Plan as modified by this Decision may be different from the Companies' projections. The Companies may need to revise the in-service date associated with their incremental purchases of pipeline capacity. Based on the aforementioned, the Authority will direct the Companies to examine whether the proposed capacity plan is still fully needed to meet the expected increase in the design peak day demand. If the full amount of the capacity plan is no longer needed to meet the Companies' expected design peak day demands or if the timetable for need has changed, the Companies shall submit a modified capacity plan for the Authority's approval.

The Authority reminds the Companies that preapproval of the Precedent Agreements does not include any preapproval of commodity costs included in the purchased gas cost adjustment clause (PGA). The Authority expects the Companies to effectively manage their gas supply portfolios and obtain the lowest cost, most reliable gas supplies that are available for the ratepayers. The Authority will examine and hold the Companies accountable for any and all issues related to the cost of gas and the reasonableness of future commodity purchases of gas supplies, including access to liquid pricing points, and capacity purchases in the relevant proceedings.

7. **Pipeline Safety**

a. **Methane Leakage Reduction Strategy**

Both the CES and the Act discuss the need to reduce greenhouse gas emissions. The Act specifically stated that the Companies' expansion plan shall include a plan to harmonize natural gas infrastructure expansion with steps to reduce methane leakage from existing gas infrastructure. Act, Section 51(a)(7). In the Plan, the Companies discuss the use of state-of-the-art plastic pipe with modern construction practices coupled with replacing older leak-prone distribution infrastructure as the most effective way to reduce emissions. Plan, pp. 50 and 76.

ENE recommended that the Authority require the Companies to monitor methane leakage rates in the distribution system and produce an annual inventory of greenhouse gas emissions attributable to the expansion for accurate climate change planning. Brief, p. 2.

The Authority agrees that using state-of-the-art plastic pipe is the best choice for reducing emissions. The Companies are advised to place a significant emphasis on expanding in areas where existing older systems contain cast iron and bare steel pipe. By focusing expansion efforts in these areas, the Companies can complete several goals at once: reducing methane leakage by replacing older leak-prone infrastructure; increasing safety by modernizing the system, increasing system reliability, increasing access to natural gas and reducing costs. The Authority encourages the Companies to monitor methane leakage rates and provide this information to the BETP.

b. **DIMP / Distribution Integrity Management Program**

The United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) recently implemented integrity management regulations for natural gas distribution systems (DIMP) that are intended to help ensure pipeline integrity and improve pipeline safety. The purpose of the DIMP regulations is to require that pipeline operators analyze their particular pipeline systems, circumstances and programs to identify potential threats that could result in high consequence accidents and to subsequently address those threats before accidents occur. If accidents occur, ratepayers are potentially impacted on several fronts including loss of life, injury, lawsuits against the Companies, higher insurance premiums, and lower investor interest. In addition to the obvious effect on health and safety, all of these would serve to drive up borrowing costs and lower interest from the public for conversions to natural gas.

One of the greatest threats to the Companies' system integrity is old distribution infrastructure, such as cast iron and bare steel piping. The only significant way to reduce the threat of cast iron and bare steel pipe leaks is replacement. In addition, another one of the key elements of DIMP is the need to demonstrate improvement in the safety of the Companies' systems. For the Companies to demonstrate the required safety improvement, it will be necessary to remove, at a significantly faster pace, the cast iron and bare steel piping from their systems.

The expansion of the natural gas infrastructure contemplated in the Plan will necessitate an increase in the workforce that is involved with designing and constructing said infrastructure. This is the same workforce that is involved with replacement of leak-prone piping as well as other requirements stemming from DIMP. It is imperative that the safety of the natural gas system be given the highest priority. The natural gas expansion program must not impact replacement programs or related DIMP requirements. Based on the Authority's concern over construction resource availability and pressure to ensure that expansion targets are met, the Companies will be directed to ensure that replacement projects are given priority over expansion projects if there are not sufficient resources for both programs. The Authority will closely monitor this issue through the audits performed by the Gas Pipeline Safety Unit. In addition, it should be noted that a tracker mechanism associated with the DIMP program is not approved in this Docket. Any proposed tracker mechanisms for DIMP programs will be examined during each gas company's respective rate case.

8. **Bill Impacts / Rate Cap**

The Companies have provided an analysis demonstrating that the expected annual rate impact on customers' bills is expected to be less than 3% over the entire Infrastructure Expansion Plan. Response to Interrogatory BETP-1.The BETP stated that rate impacts in this range are reasonable in the context of lowering energy costs for several hundred thousand Connecticut families.BETP Review, p. 3.

The OCC recommended that the combined rate impact be capped at 3%. OCC Brief, p. 8. In addition, the Attorney General recommended that just and reasonable rate impacts should be no more than 3% and that this limitation should be set as a hard cap. AG Brief, p. 4.

In its Reply Brief, the BETP sought to further clarify its original statement in its review that rate impacts of less than 3% are reasonable. Any initial detrimental impact to rates will be offset over the long-term by the addition of new customers.

Consequently, the BETP urged the Authority to avoid imposing a hard annual rate cap of 3%, and to instead rely upon annual reviews where rate impacts can be scrutinized and appropriately adjusted when necessary. BETP Reply Brief, pp. 4 and 5.

The Authority is very concerned about the potential rate impact of the Plan. While some rate impact may be inevitable, the Authority wants to ensure that any increases in rates for existing customers are minimized as much as practical while at the same time expanding the current gas system infrastructure to serve new customers. However, setting a hard annual rate cap at this time can be problematic. One of the hardest risks to assess under the Plan is the Companies' ability to acquire the remaining 40% of revenues for a given project that it is discounting under the Hurdle Rate model. While the Companies will have some ability to get the remaining customers on a project, it is ultimately an uncertain prospect. Further, it will take several years for the Companies' ratepayers to be made whole on a given project, if at all. The Authority intends to review the revenues of the off-main "portfolio" projects, and adjust the Hurdle Rate mechanics if it finds this approach is causing an unreasonable adverse impact on rates.

C. HURDLE RATE

The Hurdle Rate is a financial analysis used by the Companies to determine whether a new customer can be economically served such that the revenues collected over a period of time will recover the capital investment. It is designed to ensure that new customer additions made by the Companies are not unduly subsidized by existing customers. Bachelder PFT, 7. If the customer does not pass the Hurdle Rate analysis, they would be required to pay a CIAC to be served. A Hurdle Rate seeks to provide reasonable assurances to the Companies that the revenues expected to be produced by the new customer will exceed costs, including a return of and on investment (measured over a predetermined time period). When a specific project does not pass the Hurdle Rate analysis, the Companies must secure CIAC designed to reduce investment to a level that would satisfy the test. The Companies use the weighted average cost of capital from their most recent rate case to set the return on investment to be used in applying the Hurdle Rate analysis. According to the CES, Yankee currently uses a 15-year payback period; CNG and Southern have operated under an April 2011 authorization to use 20 years under a two-year pilot program. CES, p. 152.

Section 51(d)(1) of the Act, states that the Authority shall:

> . . . establish a Hurdle Rate utilizing a twenty-five-year payback period to compare the revenue requirement of connecting new customers to the gas distribution system to determine the level of new business capital expenditures that will be recoverable through rates, provided the authority shall develop a methodology that reasonably accounts for revenues that would be collected from new customers who signaled an intention to switch to natural gas over a period of at least three years within a common geographic location.

While the changes stated in the Act would somewhat alter the economics of the Hurdle Rate analysis, projects would still need to pass the test using the longer time frame. Participating customers would still have the option to pay a CIAC to be served if expected revenues are insufficient to recover the costs. Pursuant to the Act, the Authority approves a 25-year payback period in the Hurdle Rate calculation.

1. Companies' Requests for Approvals

The Companies requested that the Authority approve the following modifications to each company's current Hurdle Rate analysis:

1. The Companies shall adopt a Hurdle Rate model incorporating 25 years of revenues for all customer classes, as required by Public Act 13-298, Section 51(d)(1).
2. There shall be no requirement to run a Hurdle Rate test for residential heating prospects with a service extension of less than 150 feet, except for non-typical on-main installations including those:
    - with runs greater than 150 feet;
    - with visible ledge or rock that will affect excavation;
    - with retaining walls;
    - that requires an easement agreement to be executed;
    - that is steel;
    - on a state highway;
    - that crosses a culvert, stream or other obstacle;
    - that would involve extensive landscaping restoration;
    - on a newly paved or concrete road; and
    - that has three or more meters.
3. Individual projects, where appropriate, shall be consolidated in a common geographical location into a "portfolio view" for purposes of running the Hurdle Rate analysis as provided by Public Act 13-298, §51(d)(1) with the following guidelines:
    - Aggregated customers must be in the same geographic area (same town or contiguous towns) where the proposed main construction will take place and capable of being served by the same gas company.
    - Properties owned by same entity: properties owned by the same entity may be consolidated if all of the properties are part of an identified planned conversion effort.
4. Consistent with Public Act 13-298, §51(d)(1), three to five years of forecasted revenues may be included in the Hurdle Rate analysis to capture anticipated customer conversions not initially supported by firm commitments at the time of initial construction:
    - A minimum of 60% of the necessary customer commitment shall be secured upfront before the Companies will proceed with a project. For example, if a residential neighborhood of 100 homes requires a minimum of 60 homes to

convert to pass the Hurdle Rate, then a minimum of 36 commitments will be secured before construction commences.
- The 60% threshold shall be reviewed and adjusted, as required, based on actual data of future load additions.
- In the case of a main extension to a large anchor load(s), the anchor customer(s) will be required to execute an installation agreement with the Companies. Additionally, if incremental customers are needed to meet the Hurdle Rate test, then a minimum commitment of 60% of those incremental customers will be secured before construction commences.

5. Societal benefits may be included in the Hurdle Rate model analysis for certain prospective commercial, industrial and government customers that are expected to provide societal benefits by converting to natural gas. The amount of distribution margin to be added to any of these projects shall not exceed 20%. Selection of projects will be developed in cooperation with the DECD and societal benefit projects will be presented to the Authority for pre-approval.

Late Filed Exhibit No. 39.

2. Parties Positions

a. BETP

The BETP contended that the Companies have done an effective job of developing an approach to the Hurdle Rate model that supports the goals of the CES and conforms to the provisions of the Act. The BETP recommended modifying the current Hurdle Rate model to:

a. extend the time horizon of Hurdle Rate model calculations to 25 years for all customers;
b. eliminate CIAC requirements for all on-main heating prospects that are located 150 feet or less from an existing main;
c. allow the Companies to consolidate individual projects into a single Hurdle Rate model analysis within a common geographic location (the "portfolio view");
d. allow the Companies to forecast future project conversions over a three- to five-year period; and
e. establish an expanded project selection and prioritization model that takes into account broader societal benefits including economic activity due to customer savings, economic development benefits from extending mains to commercial and industrial and/or State and municipal customers and environmental benefits.

Brief, pp. 4 and 8.

The BETP stated that flexibility is needed to encourage more customers to convert, but at the same time potential rate impacts to existing customers must be minimized. For that reason, the BETP recommended that forecasting be limited to three years, and extended to five years if information in the annual reports indicates the effectiveness of such forecasting. The BETP encourages the Authority to approve the Plan and makes two suggestions. First, that the list of “exceptions” to the Hurdle Rate requirement of the Companies be unified, so that there is one accepted definition to be used by theCompanies. Second that a “catch all” should be added to the list, such as: “or any other apparent or foreseeable condition which would reasonably be expected to impact installation costs.” Brief, p. 15.

The BETP underscores the importance of annual reporting and filings made by the Companies that will include year-to-date conversion revenues and costs, forecast conversion costs and revenues for the remaining months of the year. Notably, Section 51 subsection (e) of the Act provides for annual reporting by the Companies to the Authority and the BETP regarding the Plan’s progress. Such filings and the Authority proceedings will allow for a careful review including hearings to give PURA and others the ability to establish that costs and revenues were correctly calculated and costs were prudently and reasonably incurred. These filings will ensure accuracy and prudency for the entire Plan and the proposed rate-mechanisms at issue in this proceeding. Brief, p. 16.

b. Office of Consumer Counsel

The OCC stated that the Hurdle Rate model is the foundation upon which the Plan is built. It is the financial tool used by the Companies to determine if a potential new customer is economically viable. Although the Hurdle Rate model length has been adjusted through the Act, the model will still be data-driven. Given the importance of the Plan to the Companies, their existing and potential customers, and the State of Connecticut, it remains imperative that reliable data inputs in the Hurdle Rate calculations be used for it to be a viable and effective financial tool. However, the record revealed that the data used in the Hurdle Rate model to date has had serious shortcomings. The OCC was surprised to discover that:

a. the Hurdle Rate model results did not accurately predict cost-effective customers;
b. both the load estimates and the capital cost estimates were inaccurate;
c. load estimates were consistently high and capital cost estimates were typically low, allowing non-cost-effective customers to be approved;
d. CNG and Southern did not keep the data in their model updated;
e. the depreciation rates in the current model are outdated;
f. Yankee does not include O&M in the model; and
g. the Companies did not have effective contract enforcement with their new customers to regulate new customer load projections.

Brief, pp. 34 and 35.

The OCC argued that it is critically important that the Hurdle Rate model be effective in forecasting which new customers will be cost-effective. The OCC cites the Companies load and capital cost estimates for 2003 through 2010 that show little progress in achieving accurate forecasts. The OCC recommended that each gas company perform an internal audit to determine correction factors for the estimates of load and capital cost at least every two years. For the present, the Hurdle Rate models should be modified according to the following factors based on the latest gas company study:for Yankee, reduce the estimated load by 31% and increase the capital cost estimate by 25%;for CNG and Southern, reduce the estimated load by 35%;the Lost Load Study conducted by CNG/Southern does not address capital cost estimates. However, the internal audit does look at the accuracies of the capital cost. The OCC recommended that the Authority order the CNG/Southern internal audit department to update the August 2013 audit within 60 days of the final Decision to provide updated factors. Brief, pp. 35-39.

Further, the CNG/Southern model data is not updated and Yankee does not normally include operations and management expenditures (O&M) in the model unless it is a special O&M. CNG and Southern include O&M in their Hurdle Rate model and the Authority should order Yankee to do the same. Regarding the forecasted O&M in the Hurdle Rate model, CNG and Southern are proposing to include all the O&M identified in the Plan except the “Other O&M.” As the Hurdle Rate model is a tool to determine if a potential new customer is cost-effective, all the costs should be included in the model. Further, Yankee wants to wait to include Plan O&M in the model until there are actuals and the OCC disagrees with this approach. Since Yankee estimates load and capital costs for the model now, the O&M would be just another estimate and such O&M estimates should be included in the model. The OCC recommended that all Plan O&M be included in the Hurdle Rate model at the start of Plan implementation. In terms of defining the types of O&M to include, the OCC recommended that any O&M that the Companies can or might collect through the SER and/or NFM be included. In this way, a cost-effective customer would provide the appropriate level of revenues to pay for these items, and these costs would not be shifted to existing customers. Brief, pp. 39-42.

Regarding new customer contract enforcement, CNG and Southern had no documented enforcement actions during the past five years and Yankee claims that in the past year there is a “Grand Total” of 35 enforcement actions. The OCC recommended that the Authority require all of the Companies to develop contract enforcement policies and monitor compliance. The OCC stated that another issue is that Yankee’s policy only audits customers that have a construction cost of $50,000 or greater. Construction cost is the wrong audit initiating criteria; the criterion should be based upon load, which is the important quantity. Brief, p. 43.

c. Attorney General

The AG stated that the Hurdle Rate determines the amounts that existing gas customers should pay to expand the system to new customers. Any costs beyond the

Hurdle Rate amounts must be paid by the new customer(s). The proposed changes to the Hurdle Rate present risks associated with projecting future conversions that must be fairly allocated between the Companies and their ratepayers. The Authority must, among other things, establish a Hurdle Rate utilizing a 25-year payback period. Also, to develop a methodology that reasonably accounts for revenues that would be collected from new customers who signaled an intention to switch to natural gas over a period of at least three years within a common geographic location. Brief. p, 4.

Although the BETP recognized the risk that changes to the Hurdle Rate present to existing ratepayers, it only proposed to monitor those risks and allow for the possibility that adjustments to the Hurdle Rate could be made in the future. This does not adequately protect ratepayers because the Companies may have incentives to overestimate future revenue streams. In the event the projected future customers fail to appear, the Companies' existing ratepayers could be required to subsidize the revenue shortfall. If the Companies are permitted to project future customers when calculating the Hurdle Rate, the Authority should hold the Companies to those projections to encourage them to avoid uneconomic system expansion. The Authority could, for example, hold the Companies to their projections by applying their Hurdle Rate projections when forecasting revenues in rate proceedings. This would encourage the Companies to project future expansion reasonably and avoid inappropriate and unnecessary revenue shortfalls that would otherwise be assigned to existing customers.

The need to protect existing ratepayers from unreasonably optimistic Hurdle Rate forecasts is clear. The Companies have a poor track record of projecting the costs and revenues associated with new customers. Historically, the Companies have vastly understated projected construction costs associated with new customers and have significantly overstated gas consumption levels by those new customers. These poor projections have resulted in the Companies' understating the required CIAC from new customers which, in turn, imposed additional costs on existing customers. The Companies have a strong financial incentive to expand the gas distribution system. System expansion means more paying customers for the Companies as well as a larger rate base on which it can earn a return. This incentive could encourage the Companies to understate construction cost estimates and overstate consumption projections to justify uneconomic system expansion. The Authority should protect existing and future gas ratepayers from uneconomic system expansion by fairly allocating the risks of uneconomic system expansion on the Companies and holding the Companies accountable for their projections. Brief, pp. 6 and 7.

d. Environment Northeast

ENE recommended that the Authority consider making certain modifications to the proposed Plan to lower the Plan's risks and also to better allocate those risks. These modifications would help avoid long-term overinvestment in natural gas distribution infrastructure by ratepayers that could lead to a burdensome "stranded cost" scenario. The Companies' Hurdle Rate analysis should be tightened to focus the expansion on only the most cost-effective and lowest-risk proposed conversions. More conservative modeling assumptions can be used – in particular, assuming the installation of high efficiency natural gas equipment. This would create a Hurdle Rate analysis that would be more protective of ratepayers by only approving those proposed conversions that have some margin for error in their cost-effectiveness to handle unexpected risks, such as a major increase in the price of natural gas.

Another possibility for refining the Hurdle Rate analysis could include running a worst-case cost-effectiveness scenario that combines an efficient equipment assumption with a high natural gas price assumption. The Authority could establish a cost-effectiveness rule, for instance, that would only allow proposed conversions that score above a certain threshold of this worst-case scenario. For all of these reasons, ENE opposes exempting all "on main" conversions from any Hurdle Rate analysis, as proposed by the Companies. Physical proximity alone – being located within 150 feet of an existing distribution main – is not sufficient to establish the sound presumption of a cost-effective conversion. Other key factors, such as the price of natural gas and whether the customer installed efficient natural gas equipment, will also have a significant effect on the results of any cost-effectiveness testing of "on main" conversions. Brief, pp. 2 and 5.

3. Discussion

During the proceeding, it appeared that there was confusion whether a customer was either on-main or off-main. The Authority defines an on-main customer to be one that has an existing main that is directly in front of the customer's premises as of December 31, 2013. If any addition of a main in the street is necessary to connect a potential customer, that customer is defined as an off-main customer.

a. 150-Foot Residential Service Extension

The Companies proposed that a Hurdle Rate analysis be performed for all potential on-main residential heating customers requiring a length of service pipe more than 150-feet away from an existing main. For those potential customers with a service extension of less than 150-feet, a Hurdle Rate analysis would not be performed except for non-typical installations (defined as an exception). The Companies proposed largely overlapping, but not identical exceptions to the 150-foot on-main rule. Yankee proposed three types of exceptions to the rule where a Hurdle Rate analysis would need to be performed: (a) presence of visible ledge or rock; (b) presence of retaining walls or extensive landscaping; and (c) installations requiring new or expanded access rights. CNG and Southern proposed the following exceptions to the rule: (a) need for detailed engineering design or cost estimates (including all steel installations); (b) unusual excavation or restoration conditions producing much higher than average costs; (c) significant rock; (d) on state highways; (e) crossing culverts, streams or other obstacles; (f) extensive landscaping restoration; (g) on newly paved or concrete roads; (h) requiring new easements; and (i) premises of at least three meters. Companies Responses to Interrogatory OCC-115. Subsequently, the Companies consolidated their on-main proposals and provided the list cited above of "non-typical" occasions when they would run a Hurdle Rate analysis, which potentially could require a CIAC. Joint Companies Brief, p. 9.

ENE opposed exempting a broad 150-foot exemption from Hurdle Rate analyses. ENE considers physical proximity to be an insufficient reason for presuming cost effectiveness, citing other factors, such as gas prices and efficiency of customer equipment to be installed. Brief, p. 5.

The OCC raised a vintage question with respect to defining “on-main customers.” Specifically, whether potential customers within 150 feet of an installed main are on-main customers, or should be considered off-main. The OCC urged a determination that customers who are definable as off-main as of 2013 remain so for the Plan’s 10-year duration. This determination affects the obligation to pay premium rates under the SSR. Brief, p. 5.

The Authority reviewed the proposal that residential customers less than 150 feet from an existing main do not need to have a Hurdle Rate analysis performed (Rule) and finds the Rule reasonable. The Rule would make the administrative process of connecting a potential new residential customer more efficient and reduce the amount of a sales representatives’ time when marketing service to potential new customers. The Authority agrees that the Companies exemptions to the Rule need to be expanded. The inclusion of a catch all clause would allow them to return to the potential customer if unforeseen condition(s) were to occur during excavation. Item two of the non-typical on-main installation items, cited in Section C.a. Companies Requests for Approvals, states “with visible ledge or rock that will affect excavation.” However, unforeseen conditions such as environmental contamination, hidden rock or an underground septic system could exist. Obviously these unforeseen conditions would not be visible. Therefore, the Authority directs the Companies to remove the term “visible” from this item so that it reads “with ledge or rock that will affect the excavation.” With this change, the Authority finds the proposed Rule acceptable.

The Authority will direct the Companies to file annual reports to address on a categorical level, the costs per installation for extensions in each of the nine listed categories in Item two. These reports should identify and discuss (quantitatively and qualitatively) any additional categories of construction cost (e.g., over-runs, penalties) associated with on-main extensions.

b. Portfolio View for Aggregating Customers

In Item 3, Section II.C.1.Companies’ Requests for Approvals, the Companies requested that the Authority approve a portfolio view for aggregating off-main customers and “running the hurdle rate analysis.” It specifically stated:

3. Individual projects, where appropriate, shall be consolidated in a common geographical location into a “portfolio view” for purposes of running the hurdle rate analysis as provided by Public Act 13-298, §51(d)(1) with the following guidelines:

    - Aggregated customers must be in the same geographic area (same town or contiguous towns) where the proposed main construction will take place and capable of being served by the same gas company.

    - Properties owned by same entity: properties owned by the same entity may be consolidated if all of the properties are part of an identified planned conversion effort.

Late Filed Exhibit No. 39.

While Section 51(d)(1) of the Act discusses new customers within a common geographical location, the legislation is vague as to the definition of “geographical location.” The Authority interprets this to mean off-main customers within the same geographical location as those customers that would be along a route where one continuous main can be placed into the ground. The Authority finds that the portfolio view should result in enhancing the efficiency and lowering the overall cost associated with installing a main extension project. In the above request for approval, the use of the term “same town or contiguous towns” or the term “properties owned by the same entity may be consolidated if all of these properties are part of an identified planned conversion effort,” could potentially allow the Companies to develop projects to serve off-main customers in different parts of a town or multiple towns. The Companies could then include these projects in the portfolio view and in one Hurdle Rate analysis. This could ultimately mask the true costs of a project within the Hurdle Rate analysis, thereby, potentially shifting additional costs into the SER or through the rate case process to all customers.

The Authority finds the “portfolio view” of off-main customers allowed in a Hurdle Rate analysis should be clearly stated. An acceptable portfolio view of customers allowed in a single Hurdle Rate analysis would be those customers on a continuous main or a single customer with multiple locations. Based on this interpretation, the Authority will direct the Companies to incorporate the above cited definition when creating a portfolio view of customers. As the portfolio view is a new approach, the Authority will monitor and possibly revisit the above definition over the life of the Plan.

c. 60% Customer Commitment

The Companies proposed that a minimum of 60% of the necessary residential and/or commercial and industrial (C&I) customer commitments in a designated portfolio view be secured upfront before they proceed with a project. For example, if a residential neighborhood of 50 homes requires a minimum of 30 homes be converted to pass a single Hurdle Rate analysis, then a minimum of 18 (30 x 60%) commitments must be secured before construction commences. The Companies requested approval to have the ability to review and adjust, as required, the 60% threshold based on actual data associated with future load additions. Further, in the case of a main extension to a large anchor load(s), the anchor customer(s) would be required to execute an installation agreement with the Companies. Additionally, if incremental customers are needed to meet the Hurdle Rate test, then a minimum commitment of 60% of those incremental customers would be secured before construction commences. Late Filed Exhibit No. 39.

While the Authority agrees with the Companies that a new customer commitment threshold should be obtained before any portfolio view project proceeds, it finds that a revenue-based threshold is superior to a customer-count threshold. The Companies will be expected to perform an anticipated full customer hurdle rate model to quantify the profitability of each project. Profitability will then be used to rank project implementation. The Companies will also perform a breakeven Hurdle Rate model for each project. Projects can proceed to construction when enough signed customers have been acquired to provide 60% of the minimum amount of revenue necessary to breakevenin the Hurdle Rate model. The Companiesshould also havea reasonable amount of prospective customers along the project to obtainthe remaining 40% of revenue necessary to breakeven in the Hurdle Rate model in a 3- to 5-year period. Any further adjustments to this percentage must be proposed to the Authority in a contested proceeding for approval,since it would change the risk to the ratepayers associated with a proposed project, and have a potential rate impact.Finally, in the case of a main extension to a large anchor load customer(s), the Authority approves the Companies' request to require these customers to execute an installation agreement as it is an appropriate safeguard for ratepayers.

d. Forecasted Additional Revenues

CNG / Southern and Yankee each proposed a different way to include three to five years of forecasted future revenues in the Hurdle Rate analysis to meet the legislative mandate. CNG and Southern intend to use a standardized process to predict future forecasted sales and revenues after year one of the project by assuming that a percentage of the remaining available prospects would convert during each successive year. During year two, CNG and Southern anticipate 20% of the remaining customers would convert, in year three 15%, year four 10%, year five 10% and 10% of the remaining customers would convert in year six. Yankee testified that its experience with marketing to potential customers associated with expansions is limited. Consequently, Yankee used information provided by its affiliateNStar Gas Company (NStar) regarding its forecasting methodology. NStar's methodology shows a 50% penetration in year one and an additional 10% of customer growth for each year after the project is complete. By the third year, NStar anticipates a total customer penetration of 70%. NStar's conversion rates are anticipated by Yankee to be similar to what it should be can obtain during the same period of time. Companies Responses to Interrogatory EN-56; Yankee Response to Interrogatory OCC-21.

As discussed in Section C.1.e.iii. 60% Customer Commitment, the Authority finds that the Companies must use three to five year of forecasted future revenues as opposed to customer counts in the Hurdle Rate analysis to comply with the Public Act.

e. Inaccurate Estimates in the Hurdle Rate

The cost, sales and revenue estimates are the most important components of conducting a Hurdle Rate analysis. The OCC did a thorough review, analysis and presentation on the ability of the Companies to conduct Hurdle Rate analysis accurately. The OCC requested that the Companies provide internal audit reports and/or analysis that verified the accuracy of historic Hurdle Rate estimates. Yankee responded that it has not conducted an internal audit of the Hurdle Rate model and/or its input data in the past 10 years. Yankee Response to Interrogatory OCC-14. However, Yankee performed some internal analysis, namely, a Post Mortem Report on load and capital cost estimates. Yankee Response to Interrogatory OCC-15. In these reports, the annual consumption estimates were uniformly higher than the actuals and the capital cost estimates were typically lower than the actuals. Below is a summary of all of the Yankee Post Mortem Reports.

Year	Load Estimate	Capital Cost Estimate
2003	Overestimated by 35%	Underestimated by 13%
2004	Overestimated by 18%	Underestimated by 1.46%
2005	Overestimated by 17%	Overestimated by 2%
	Residential overestimated by 39%	
2007	Overestimated by 31%	Underestimated by 35%
2010	Overestimated by 31%	Underestimated by 25%

Yankee Response to Interrogatory OCC-15-RV01.

Each report for each year contained similar recommendations to recalibrate the load-estimating and capital cost estimate procedures. Yankee verified that all recommendations were implemented. Tr. 9/11/13, pp. 417 and 418. However, the summation above shows that little progress in achieving accurate forecasts was accomplished even though all recommendations were implemented. Yankee stated that it has been working on this problem since 2003, when its Post Mortem Report stated that load was overestimated by 35% and capital cost underestimated by 13%. Again, the evidence suggests little progress as the 2010 report stated that annual consumption was overestimated by 31% and capital cost underestimated by 25%. Id.

CNG and Southern provided a 2011 Lost Load Study, which showed residential load overestimated by 43% and C&I by 32%, for a total of 35%. CNG and Southern Response to Interrogatory OCC-15. In addition, CNG and Southern provided an internal audit dated August 2013, which reached the following conclusion:

> The analysis of the construction cost estimates indicated that more than 60 percent of the projects we tested had variances where estimates either exceeded or understated actual construction costs beyond 20 percent.

> The analysis of consumption estimates of consumption across three years indicated that more than 90 percent of the projects were over-estimated and that 80 percent of these projects had estimation variances greater than 25 percent. It is our opinion that the estimation variances are much too high based upon the results of our sample of projects that was tested. Therefore, Business Services management should take the necessary steps to improve the accuracy of construction projects and consumption estimates.

CNG and Southern Response to Interrogatory OCC-14, Supplement, Attachment 1, at 3.

All of the CNG and Southern studies and internal audit reports have one theme in common; the load is consistently overestimated by as much as 43%.

The Authority finds the inaccurate estimates included in the Hurdle Rate analysis for all three Companies unacceptable. The inaccuracies show that the Companies process for controlling and monitoring the project cost estimates and the projected sales included in the Hurdle Rate analysis inadequate at best. The most troublesome part of the inaccurate estimates is that Yankee performed five Post Mortem Reports during the past 10 years and still has a high level of inaccuracies. Each report included similar recommendations and Yankee implemented all of them. Tr. 9/11/13, pp. 417 and 418. The results of these reports show that since the 2004 report, Yankee's estimating errors have almost doubled. Regarding CNG and Southern, they have only performed one complete study (during 2013), where the results were worse than any of the Yankeeresults.

These large estimation errors definitely affected the outcome of the historic Hurdle Rate analyses. These errors may have resulted in a significant number of customers either paying CIACs when they were not needed or not paying CIACs when they should have. The Authority concurs with the OCC and the AG that the Companiesshould be held accountable for their forecasting inaccuracies. The Authority understands that some amount of variation between the estimates and the actual costs, sales and revenue forecasts can occur. To encourage the Companies to improve their estimates included in a Hurdle Rate analysis, the Authority finds it reasonable to allow no more than a 20% difference between the estimated and actual costs, sales and revenue. One way to correct the estimation error issue is to hold the Companies to their estimates in their respective Hurdle Rate analysis. For the Authority to monitor these ongoing calculations, the Companies will be directed to submit a monthly compliance filing that shows the original Hurdle Rate Summary page associated with each off-main portfolio view / project the company began construction on during that month. A year after the gas flow has begun to be metered,the Companies will submit another Hurdle Rate Summary page detailing actual cost, sales and revenues. In addition, the Companies will be directed to provide a working excel spreadsheet comparing the original estimates to the actual data. With that data, a true-up of the estimates in the model to the actuals for each portfolio view project will be completed. The Companies and not the ratepayers will be responsible for any estimation error that is greater than 20%.

The Authority will direct the Companiesto hire an outside consultant that has a working knowledge of the issues associated with Hurdle Rate estimation inaccuracies. This individual or company could analyze the input data being used and analyze the sales forecasting models to determine how the Companies can improve their future estimations. The results of that review should be filed with the Authority.

f. Societal Benefits Hurdle Rate

The Companies proposed a second Hurdle Rate model entitled Societal Benefits Hurdle Rate. The analysis would be for certain prospective C&I and/ormunicipal customers that are expected to provide societal benefits by converting to natural gas. The proposed amount of distribution margin to be added to any of these projects would not exceed 20%. Selection of projects would be developed in cooperation with the DECD and societal benefit projects would be presented to the Authority for pre-approval. Late Filed Exhibit No. 39. The Companies testified that the intent of the Societal Hurdle Rate is specifically related to those projects that are important to the state but do not pass the Hurdle Rate analysis. The Companies also testified that they will develop a list of projects and present them to the DECD for approval. The Companies would then submit the list of projects for the Societal Benefits Hurdle Rate to the Authority for its approval. Tr. 9/10/13, pp. 193-200.

In addition, the Companies testified that they are in the process of finalizing, over the next six months, a Memorandum of Understanding (MOU) between them and the DECD. The final MOU would include a provision as to the annual costs related to the DECD's annual analysis of Societal Benefits Hurdle Rate projects. The annual costs associated with any DECD analysis would then be passed on to ratepayers through the annual tracker. Tr. 10/2/13, pp. 1538–1554.

The Authority finds there is no requirement that a separate Societal Benefits Hurdle Rate model be designed. The Authority defers approving any MOU or any financial commitments associated with oneuntil the MOU has been provided. Further, the 20% of additional revenue with no limit on the amount of dollars involved, over and above the legislatively mandated three to five years of revenues that the Companies proposed to include in the existing Hurdle Rate places the ratepayer at significant financial risk. The Act requires that NFM be used to offset costs associated with these types of projects, effectively limiting the dollar amount by which the projects are to be supported by ratepayers. See, II.D.2.<u>Assignment of Non-firm Margin Credits</u>.Based on these factors, the Authority will not approve a separate Societal Benefits Hurdle Rate at this time. The Authority directs the Companies to use the standard Hurdle Rate model on societal benefits projects and use the NFM to offset some of the costs as discussed in Section II.D.2.

D. RATES AND RECOVERY

The BETP recommended the following changes to traditional rate-making policies and practices.

1. **Alternate Rate Rider to Pay Customer Main Extension Costs:**

   The CES recommended that the Authority allow new customers to pay their CIAC charges over time through payments on their gas bill, instead of requiring an upfront payment.

2. **Establish a Mechanism for Timely Recovery of Capital Expenditures Made by the Gas Companies:**

   Due to the capital-intensive nature of a large-scale natural gas expansion program, the CES proposed that the Authority consider establishing a mechanism for the gas companies to recover prudent investments in a timely manner, outside of a rate proceeding.

3. **Sharing of Purchased Gas Adjustment Credits:**

   In developing the gas expansion plan for submission to DEEP,[2] the Companies should propose methods that the Authority could consider for reassigning some or all of the Purchased Gas Adjustment Credit to support system expansion.

CES, pp. 152-154

The Companies' Plan contains these same changes. The proposal for an infrastructure-expansion tracker reflects a growing trend in utility rate-making. The Companies report that a number of states are using infrastructure-expansion trackers to support increasing access to gas service for residents and businesses. Plan, p. 11. A problem addressed by the trackers is regulatory lag. Traditional rate-making practices do not provide rate relief as timelyas trackers do in the face of rapid increases in revenue requirements occasioned by fast-paced system expansion.

As a result of the recommendations in the CES noted above, Connecticut's legislature mandated a series of changes. The table below lists the relevant requirements in the Act and the Companies' proposed elements intended to fulfill those requirements.

Requirements for the Authority in Public Act 13-298	Proposals
(1) Establish a new rate for new customers added to offset incremental expansion costs	SSR
(2) Establish a rate mechanism for to recover investments timely and outside a rate proceeding, considering additional revenues	Expansion tracker / SER

[2] Public Act 13-298 required that the Plan be submitted to the DEEP and the PURA at the same time.

generated	
(3.A) Assign at least half the non-firm margin credit to offset rate base (3.B) Assign lesser of (i) half of the non-firm margin credit, or (ii) fifteen million dollars from the credit, apportioned to each gas company in proportion to revenues and existing and new capacity contracted for by each gas company, to offset expansion costs, including but not limited to, the costs of new state, municipal, commercial and industrial customer additions providing societal benefits	Sharing NFM credits

1. Shared Savings Rate / SE rate

To help fund the system expansion envisioned by the CES, the Companies proposed new customer rate tariffs to help minimize the impact of the expansion on existing customers. The Companies titled the proposed rate tariffs the "SSR", which would apply to new customers as of January 1, 2014. CNG and Southern proposed charging the SSR only to new off-main customers, while Yankee proposed charging the SSR to both new off-main and new on-main customers. The Companies recommended the SSR be applicable for seven years for each customer from the time they come online, after which the customer would be transferred to the applicable existing customer rate class. The proposed SSR represents a 30% premium over the customer's applicable distribution rates. This allows new customers to pay a portion of what would otherwise be upfront costs over time while contributing the cost of the necessary expansion of the gas system. Plan, pp. 18-20.

Yankee stated that the SSR was designed with two goals: (1) to achieve a bill savings for customers to help pay for conversion costs from oil to gas, and (2) to provide a reasonable amount of incremental revenue to contribute to the Plan's revenue requirement so that the rate impact to existing gas customers is minimized. The 30% increase in distribution rates was a judgment Yankee made to achieve a balance between these two primary objectives. According to Yankee, a higher SSR premium would contribute more to the Plan's revenue requirement, but leave less of a customer savings, making it more difficult to achieve an overall payback for converting customers. A smaller SSR premium would contribute less to the Plan's revenue requirement, but enable a larger payback opportunity for converting customers. Yankee Response to Interrogatory OCC-39; Tr. 9/17/13, pp. 1168 and 1169.

CNG and Southern stated that the 30% premium and corresponding proposed seven-year term are a value-based assessment given current market conditions between gas and oil and customer conversion costs. The 30% of distribution revenues was derived based on the total annual savings for a typical residential customer, and a reasonable amount for system expansion that would not materially affect the Companies' ability to convert the number of customers contemplated in the CES. CNG/Southern Responses to Interrogatories RA-10 and OCC-39; Tr. 9/17/13, p. 1170.

The Companies stated that while they attempted to align their application of the SSR, they were unable to do so because of the Companies' different geological footprint, conversion opportunities and estimated bill impacts. If Yankee were required to modify its proposed treatment of the SSR to apply only to off-main customers, the result would be a greater impact on existing ratepayers. The Companies contended that Yankee's proposed SSR treatment strikes the necessary balance, allowing Yankee to achieve its conversion targets and is in the best interest of Yankee's ratepayers. Companies' Joint Brief, p. 11.

The OCC agreed that the SSR would be an appropriate mechanism to achieve the goals of the Act and the CES. However, the OCC disagreed with Yankee's decision to apply the SSR to new on-main customers. The OCC maintained that Yankee should apply the SSR to those customers who do not pass the Hurdle Rate using existing rates; however, new residential customers on a main who meet the 150 foot criteria should be placed on the applicable existing rate, not the SSR. Bachelder PFT, pp. 13 and 14.The OCC objected to Yankee's proposal to charge the higher rate to new on-main customers. The reasoning is three-fold:

1. On-main customers should be economic for the companies to add in the absence of any special provisions for the Expansion Plan; therefore, there is no reason to charge them a large premium.
2. A cost differential exists between on-main and off-main additions; a legitimate purpose of a premium is to address that differential.
3. Blending the on-main and off-main groups masks the true costs of off-main expansion, including potential cost-estimation errors.

Tr. 9/18/13, pp. 1420-1422.

The OCC also maintained that the Companies could increase the number of years they would charge the SSR to allow for new off-main customers to cover their costs. For instance, the Companies could consider a ten-year SSR instead of the proposed seven-year SSR. BachelderPFT, p. 15.

The AG stated that Yankee's approach is consistent with the requirements of the Act as well as the goals of the Plan, and the Authority should not approve a proposal which allows CNG and Southern to charge rates differently than Yankee under the same Plan. The inclusion of on-main customers in the SSR effectively assigns a greater proportion of the costs of the Plan to new customers whether on-main or off-main, protecting existing gas customers from funding more of the gas expansion. Brief, pp. 16-18.

The ConnecticutIndustrial Energy Consumers (CIEC) also supported the inclusion of on-main customers in the SSR so that existing customers are not required to subsidize new gas infrastructure for other new customers. This concern is particularly acute in the C&I sector, where existing gas customers could be asked to fund cost-reduction efforts for potential competitors. In the same vein, the CIEC supported the idea of either increasing the rate or the term of the SSR, to cover the otherwise-applicable CIAC cost. The concern again being, existing C&I customers may have invested hundreds of thousands of dollars to become gas customers without the benefit of subsidies from other customers, and may be asked to contribute funds for natural gas conversion projects for potential competitors. Brief, pp. 3-9.

The Authority hereby approves a new set of rates for new customers to offset the incremental costs of expanding natural gas infrastructure pursuant to the Plan. The Authority finds that the SSR proposed by the Companies would be more aptly named the System Expansion (SE) rate as the term "shared savings rate" is a misnomer. Therefore, each of the Companies will have five new firm customer tariffs,[3] which will be "SE" rates that are identical to the five major firm tariffs[4] except that the charge includes a premium. For example, CNG's residential heating rate (Rate RSH) will now have a companion tariff for new customers added after January 1, 2014, called Rate RSH-SE. The Companies will be directed to file new tariffs in accordance with this Section either in an outstanding rate case or in a limited reopener of their last rate case.

The Authority also finds the 30% SE premium for all off-main residential customers to be sufficient at this time. The 30% increase to new average residential customers on the SE Rate increases the payback period from 5.4 years to 6.2 years for both CNG and Southern customers. The 30% increase to new average residential customers on the SE Rate also increases the payback period for a Yankee customer from 6.8 years to 8.3 years. Companies' Responses to Interrogatory BETP-7.

The Companies provided an analysis of the proposed SE premium and itseffect on distribution revenues and annual savings when certain customers convert to natural gas. An analysis of bill impacts and payback for C&I customers was also provided. The tables below demonstrate the resulting change in payback period with a proposed SE premium for the Companies' C&I customers.

CNG Rate	**Payback Base (Yrs.)**	**Payback w/30% SE premium (Yrs.)**
SGS	4.7	5.8
MGS	1.2	1.3
LGS	0.2	0.2

Southern Rate	**Payback Base (Yrs.)**	**Payback w/30% SE premium (Yrs.)**
SGS	4.4	5.4
MGS	1.2	1.3
LGS	0.2	0.2

Yankee Rate	**Payback Base (Yrs.)**	**Payback w/30% SE premium (Yrs.)**

[3] Residential General (non-heating) service will not have an SE companion tariff as very few new customers are expected to take service under this rate.

[4] Residential Heating Service, Residential Multi-dwelling Service, Small General Service, Medium General Service and Large General Service.

Rate 10	4.5	5.6
Rate 20	1.3	1.4
Rate 30	1.1	1.1

Plan, Exhibits II-3 through II-5; Interrogatories RA-1, RA-10 and OCC-39.

Based on the aforementioned, the Authority finds that a 30% SE premium for all off-main C&I customers is also reasonable because of the minimal increase to already short payback periods. The Authority finds that the 30% premium proposed by Yankee for on-main customers is high, given the economics of the on-main customer segment. A 10% SE premium for on-main customers is appropriate for each of the Companies to recover some of the incremental costs of the Plan. These costs include but not limited to costs associated with the change to a 25-year Hurdle Rate, the elimination of the requirement to run a Hurdle Rate test for all residential on-main heating prospects that are located 150 feet or less from an existing main and other Plan costs such as marketing, incentives and customer-financing costs. Requiring new on-main customers to pay a 10% SE premium helps further protect existing gas customers from paying a disproportionate amount of the costs of the gas expansion that will directly benefit new customers.

The Authority accepts the OCC's argument that the proposed seven-year term for the SE Rate should be extended to a ten-year term to align better with the duration of the Plan and further mitigate potential rate increases to existing gas customers. The Authority approves the implementation of SE rateseffective January 1, 2014,with applicable SE premiumsforall new customers[5] as follows:

1. A 10% premium for all new on-main customers for each of the Companies.[6]
2. A 30% premium for all off-main residential and C&I customers for each of the Companies.
3. A ten-year term for the SE Rate.

The Companies also proposed that the draft Decision be amended to acknowledge that any customers that sign conversion contracts in 2013, but will not begin to receive gas until 2014, be grandfathered under existing rates. Comments, p. 30. The Authority grants this request but notes that service requests for these customers must be granted pursuant to the existing Hurdle Rate treatment and the resulting CIAC, not the modified Hurdle Rate established herein.

2. Assignment of Non-firm Margin Credits

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[5] Existing, low-use customers can be placed on standard tariff rates, since they are existing customers as of January 1, 2014.

[6] The Companies shall define a new on-main customer as "one, who as of December 31, 2013, has an existing main that is directly in front of the customer's premises, and who becomes a company customer on or after of January 1, 2014".

The BETP concluded that “using a portion of the Non-Firm Margin credit to offset rate base or other costs incurred for expansion would reduce the possible impact on existing customers. . . . Another approach would be to use a portion of the NFM credit to reduce the CIAC costs for off-main customers converting to gas. In developing the gas expansion plan for submission to the BETP, the companies should propose methods that the Authority should consider for reassigning some or all of the Purchased Gas Adjustment Credit to support system expansion.” CES, p. 154.

The Act prescribed the treatment of NFM generated during the period of the natural gas expansion plan as follows:

> (A) assign at least half of the nonfirm margin credit to offset the rate base of the gas companies, and (B) assign the lesser of (i) an amount equal to half of the nonfirm margin credit, or (ii) an amount equal to fifteen million dollars from the nonfirm margin credit annually for all gas companies in the aggregate, apportioned to each gas company in proportion to revenues of and the existing and new capacity contracted for by each gas company, to offset expansion costs, including, but not limited to, the costs of adding new state, municipal, commercial and industrial customers where such additions provide societal benefits, including, but not limited to, increased or retained employment, local economic development, environmental benefits and transit-oriented development goals.

Act, Section 51(d)(4).

The Companies proposed to assign half of the NFM credit to offset rate base of the gas companies and use the remaining allowed NFM credit to offset revenue requirement shortfalls that may occur after incremental rate revenue and shared savings rate revenue is applied. Plan, p. 21, 110 and 112. Further, the Companies seek approval to “bank” surplus NFM credits where a revenue requirements deficiency is reasonably anticipated in the next two to three year period. Any remaining NFM credits not “banked” will be returned to ratepayers through the PGA.

The Parties were asked to brief on the intended application of NFM for gas expansion pursuant to §51(d)(item 4) of the Act. The Parties generally agreed on the first assignment to use at least half of the NFM credit as an offset to rate base. Regarding the second assignment in Section B above, there was some differences of opinion as to whether this portion of NFM could be used to further offset existing rate base, offset expansion costs (including the SER), banked by the Companies or return back to customers through the PGA. See, the Briefs ofthe AG, pp. 15 and 16; OCC, pp. 11-19;Companies, pp. 14-16;andBETP, pp. 11-12.

The OCC also noted that the shifting of the NFM should be accounted for as part of the overall impact of the Plan on customers. Brief, p. 8. The Authority agrees. On several occasions during the course of the proceeding, the Companies indicated they may not need to charge an SER in carrying out the Plan. This claim was made by the Companies based on their proposal to redirect NFM credits to offset the SER. In the opinion of the Authority, the redirected NFM should be included in the bill impact analysis that the Companies will provide annually pursuant to Section II.E.1. Reporting Requirements.

Therefore, the Authority will direct the Companies to assign at least 50% of all NFM credits[7] generated in a given year to offset gross plant additions made during that year, which should lower the Companies' rate base by the same amount. The Companiesshould assign the lesser of 50% of NFM it generates in a given year, or $15 million, primarily to offset the costs of projects deemed to have societal benefits. Additionally, the Authority will direct the Companies to develop a methodology for assigning these costs to individual projects, and, therefore, offsetting some CIAC costs for these customers, after they have concluded their work with the DECD. Any remaining NFM credits not used to offset the costs of societal benefits related projects in a given year shall be booked separately as an offset to rate base or may be used to offset a future revenue requirement deficiency at the Authority's discretion. The Authority will not approve any "banking" of the NFM at this time. Lastly, the Companies should identify the remaining NFM and proposed application in their annual reconciliation filing.

3. Infrastructure Expansion Tracker / SER

Between rate cases, the Companies make capital investments in new business. These investments are typically deferred for recovery in the next rate case, where the Authority would review them for prudency, used and usefulness and allow recovery on prudent investments. Ignoring potential decoupling impacts revenues from new customer growth can help offset the Companies' expenses between rate cases. Due to the capital-intensive nature of the Plan, the CES proposed that the Authority consider establishing a mechanism for the gas companies to recover prudent investments in a timely manner, outside of a rate proceeding. This mechanism could also be used to incorporate into rates a consideration of the additional revenues the gas companies expect to generate as more customers are added to the system. CES, p 153. This CES recommendation was adopted in the Act, directing the PURAto"establish a rate mechanism for the gas companies to recover prudent investments made pursuant to the natural gas expansion plan in a timely manner outside of a rate proceeding, provided such mechanism shall take into consideration the additional revenues that the gas companies will generate through implementation of such plan." Act, Section 51(d).

The Companies proposed that the recovery of the revenue requirements associated with the Plan be done through an annual infrastructure expansion tracker that is fully reconcilable and allows for quicker recovery. The SER is the Companies' proposed recovery mechanism pursuant to the Act. Should general rate revenue, SE

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[7] In the future, the 1% of NFM currently retained by the Companies' shareholders will be used to mitigate the expanded rate base revenue requirement.

rate revenues, and the redirected NFM prove insufficient to fund the annual revenue requirement of the Plan fully, the Companies proposed that any remaining revenue requirement be paid by existing firm customers through the SER. The Companies also proposed the revenue requirement components to be recoverable though the SER. Plan, p. 101.

The Companies were not aligned on their proposals regarding the applicability of the SER. Yankee proposed to include the full revenue requirements associated with all new business capital spent after January 1, 2014, into the SER, less the revenues collected from new customers through the SSR and the allowed level of NFM credits. Plan, p. 20. For CNG/Southern, any new business capital associated with on-main customers will be excluded from this calculation, and, therefore, it will only reconcile the revenue/expenses associated with off-main conversions. Id. CNG/Southern intend to treat the cost/revenues associated with on-main customers as "business as usual" through traditional ratemaking. Tr. 9/17/13, pp. 1105 and 1106.

The Companies also took different positions with respect to how the SER mechanism would mesh with general ratemaking. Yankee proposed that all gas expansion revenue requirements be trued up with all gas expansion incremental revenues as part of the annual reconciliation of the SER. This treatment would be in place until such time as the SE rate and SER are terminated. At that point, the SER would cease and the expansion revenue requirements and revenue will be folded into the overall rate case. CNG and Southern proposed to maintain traditional ratemaking and utilize the SER as a reconciling mechanism that compares actual results to that included in base rates. Consistent with this approach, CNG included the cost to serve new off-main customers and their anticipated revenues in its pro forma revenue requirements in its rate case application in Docket No. 13-06-08, Application of Connecticut Natural Gas Corporation to Increase its Rates and Charges, currently before the Authority. If new business revenue requirements and revenues are included in a pro forma estimate (as is the case for CNG) and can be quantified separately for analytical purposes, then an after-the-fact reconciliation can easily be performed. Late Filed Exhibit No. 32.

ENE recommended limiting ratepayers' investment risk and reallocating some risk to shareholders by capping ratepayer cost recovery and disallowing use of the proposed system expansion rate. ENE Brief, p. 2. The CIEC suggested that the Authority postpone consideration of the SER and any changes to the Companies' DIMP and decoupling mechanisms until the individual gas company rate cases. CIEC Brief, pp. 10-12.

The Authority approves the implementation of an SER for the Companies to reconcile gas-expansion related revenue requirements and revenues annually in between rate cases as of January 1, 2014. The Authority accepts the Companies' suggestion to rename the SER as the "System Expansion Reconciliation" mechanism as it more adequately reflects the purpose of this charge. The SER shall be a separate, standalone, line item on customer bills.

With regard to meshing the SER and general ratemaking, the Authority will zero-out the SER at the time of a general rate case. Essentially, the application will reflect pro forma plant, expenses and billing determinants for the totality of customers. New base rates and SE premium rates will be established anew with each case. While separate tariffs are easily created for existing and expansion customers, SE rates consist of base rates for existing customers plus a premium. To create new rate classes in the cost-of-service-study (COSS) for SE customer groupings is inappropriate. SE rates are not designed by adding a premium to their own standalone COSS derived base rates. Rather, they simply reflect a premium to existing customer base rates that are properly updated during a rate application using COSS principles. Ultimately, existing customers will pay the SER debit or credit through either the SER mechanism or through base rates. While expansion customers will also pay the cost of or receive the benefits of any SER embedded in base rates, the Authority anticipates a limited SER, if it exists at all. In any event, the SER can be controlled by altering premium payments as empirical information becomes available. Zeroing-out the SER, of course, is a rate application event that will not affect long-term program statistics for reporting purposes.

The Companies requested a ruling on whether the SER is eligible for rebate of delivery charges under the distributed generation rider (Rider DG). Late Filed Exhibit No. 39. The SER is a new distribution service charge, and as such, shall be rebatable under Rider DG. The Companies shall update their Rider DG accordingly.

a. Revenue Requirements Components

The Authority notes that it will not approve actual revenue requirements for the Companies herein, but rather establishes the components that would be recoverable under the SER. The actual revenue requirements incurred will be the product of many factors including, but not limited to,the actual capital expenditures incurred, the current and future allowed return on equity, depreciation rules, tax rules and requirements. The Authority approves the basic construct of the SER proposed by the Companies and will discuss the specific reporting requirements further in Section II.E.1. Reporting Requirements. The inclusion of all revenue requirement components in the SER is appropriate given the Act's requirement that incremental revenues be included to offset expansion costs. Because of this requirement, CNG and Southern will be directed to include their on-main revenues and costs in the SER. Excluding more than half of the customer additions in the plan appears to be contrary the intent of the SER mechanism as established by the Act wherein "the PURA shall establish a rate mechanism for the gas companies to recover prudent investments made pursuant to the natural gas expansion plan in a timely manner outside of a rate proceeding, provided such mechanism shall take into consideration the additional revenues that the gas companies will generate through implementation of such plan."

i. Rate Base

The Companies proposed to include capital expenditures into rate base, based on when the investment is projected to be placed into service. The rate base component also includes the accumulated depreciation reserve associated with the incremental capital investment included in the Plan. This balance is netted against the gross capital investment to provide the balance of capital to be recovered from customers. Plan, pp. 101 and 102. CNG and Southern estimate their total capital budget will increase from $40 to $120 million over the 10 years of the plan. Yankee estimates their total capital budget will increase from $35.2 million in 2014 to approximately $90 million by 2023. Plan, pp. 51 and 77. Currently, CNG, Southern and Yankee have allowed capital expenditures budgets of $5.4 million, $7.2 million and $17.3 million, respectively. Late Filed Exhibit No. 31.

A part of this revenue requirement calculation is the working capital component of rate base. Working capital generally represents the additional funding required to bridge the gap between the time that bills are rendered and the time that they are paid. As shown on Exhibits IX-4, IX-5 and IX-6, the Companies are not in agreement about including the working capital component in the revenue requirement calculation. Specifically, Yankee excluded working capital from its revenue requirement calculation while it was included by Southern and CNG. At the hearing, Yankee stated that its working capital was actually negative in its last rate case, and it is not appropriate to include a negative amount for system expansion. Consequently, Yankee omitted working capital altogether from its revenue requirement calculation. Tr. 9/17/13, pp. 1194 and 1195.

The Authority traditionally has included the working capital component of rate base in the revenue requirement calculation for each rate case. However, the SER proposed by the Companies will likely have a material change in the working capital calculation. Specifically, the expansion programs can be expected to materially change the timing of how the Companies will receive their total revenues. Based on the above, the Authority finds it appropriate to eliminate working capital from the revenue requirement calculation of the system expansion for the Companies. Instead, the working capital component of rate base will only be considered in each company’s rate case.

The Authority is concerned about the impact that a dramatic increase in capital expenditures will have on rates and will carefully monitor the impact of new business spending. Therefore, theCompanies will be directed to file their net rate base additions, a comparison of their gross capital expenditures vs. budget and the source(s) of new business capital in a workpaper in their SER reconciliation filing.

The Authority notes that the SER is not an automatic entitlement for all capital expenditures made on behalf of the Plan. While the regulatory changes required in the Act provide the Companies with more flexibility in planning and acquiring new business to comport with the goals of the CES, capital expenditures made by the Companies will continue to be held toexisting statutory and constitutional ratemaking principles, such as those outlined in Conn. Gen. Stat. §16-19e. This prudency standard is also reiterated in the Act whereby “the Authority shall . . . establish a rate mechanism for the gas companies to recover prudent investments made pursuant to the approved natural gas infrastructure expansion plan in a timely manner outside of a rate proceeding . . . .” (emphasis added). Rate base additions must be fully supported under the reporting requirements, discussed in more detail in Section II.F.1. Reporting Requirements. Similar to any rate amendment proceeding, the Companies must demonstrate that the plant additions made are complete, in-service and used and useful, as of the filing date to become recoverable.

ii. Depreciation Costs

The Companies proposed to include depreciation expenses associated with the incremental capital investment in their revenue requirements. Plan, p. 101. The Authority will allow recovery of depreciation expenses in the SER. The Companies should expense their plant assets under the depreciation schedules approved in their last general rate case.

iii. Operations and Maintenance Expenses

The forecasted revenue requirements include the recovery of a variety of O&M costs, including incremental O&M calculated on the basis of its historical "O&M per customer" times the number of customers it adds to the system. In addition, the Companies calculated an "O&M per mile of main" in a similar fashion based on the amount of main it installs. Depreciation expenses associated with the incremental capital investment, additions to its marketing staff, residential conversion credits and uncollectable are also included in the revenue requirements calculation.

The combined CNG and Southern gas operations' O&M budget ranges from $1.594 million in 2014 to $3.504 million in 2016.As the CNG and Southern customer count and new main increases, it will impact the O&M costs. The increased number of leak surveys, meter reading routs, periodic meter tests and other associated system costs will increase the O&M. In 2014, CNG and Southern expect to add six additional full time employees in its sales and marketing department to support the Plan. The proposed budgets will be reviewed and updated annually to account for unknown costs, such as information technologysolutions that may become essential going forward. The proposed O&M budgets represent an average O&M expenditure of $50.94 per customer. Plan, p. 51.

The Authority findsthat the inclusion of incremental O&M in the SER appropriate for ratemaking purposes. As required by the Act, the Companies must include the revenues from new customers into the reconciliation mechanism, and, therefore,they will not have the additional revenues available to offset incremental O&M incurred between rate cases. The Authority is concerned about the effect a dramatic increase in O&M will have on rates and will direct the Companies to track their actual O&M expenditures for the Plan separatelyfrom their respective general O&M for each year of the plan and provide this as the basis for recovery in the annual filing. In the annual SER filing, the Companies shall identify incremental O&M expenditures by account number and identify whether these expenditures were included in the Hurdle Rate model. The Authority will compare these figures to the proposed O&M expenditure per customer figures given in the Plan.The Authority will look to the Companies to develop goals through a Process Review Approach to drive down this cost and will consider proposed incentives for achieving such goals. See, II.B.2. Process Review / Cost Reduction Strategy.

iv. Taxes

Property taxes, gross earnings taxes, and income taxes related to the Plan incurred outside of a rate year are recoverable in the SER. With several municipalities expressing support for the gas expansion plan, the Authority suggests that the Companies discuss the tax guidelines with interested municipalities in potential new franchise areas. Specifically, to see if the potential for savings exists, such as property tax breaks, that could significantly lower the overall cost of expanding service into new and/or existing municipalities and allow more projects to meet the Hurdle Rate requirement.

b. Reconciliation of Revenue Requirements

In the Plan, the Companies proposed to file the annual SER each October and it will become effective on January first of the following year. Because the current year expense data will not be complete at the time the annual filing is made, the Companies will use eight months of actual data and four months of forecasted data.Plan, pp. 107 and 108.

The Companies proposed timeline would require the Authority to review actual data for eight months (January – August) along with a four-month forecast (September – December). Since most of the Companies' expansion projects are typically closed out in the last quarter of the year, making such a forecast could prove to be cumbersome for adequate regulatory review. The estimated four-month period, September-December, also happens to be the busiest time of year for conversions. Therefore, the chance of under- or over-forecasting costs, revenues and conversion targets increases.

The Authority will move the timing of the annual reconciliation filings to March 1st for the preceding calendar year. This shift in the timing of the annual revenue requirements reconciliation will better enable the BETP, the Authority and other stakeholders to determine whether the Companies are achieving their conversion targets, generating sufficient revenues and staying within budgeted costs and/or lowering the overall costs of conversion. This approach will allow the Authority to tie the actual expenditures to the utilities audited financial statements and annual reports. It would eliminate a review of assumptions associated with a forecast of plant additions for four months. If necessary, the Companies may also implement any new rates associated with this annual filing on March 1st subject to future adjustment after the Authority reviews the filing for prudency. The Authority will discuss the filing requirements in more detail in Section II.E.1. <u>Reporting Requirements</u>.

E. Performance Incentives/Penalties

The Companies' Plan, as originally filed, proposed an equity incentive based solely on meeting expansion goals, as shown in the following table:

CumulativeConversions	Returnon Equity PerformanceIncentiv
85%	0.50%
90%	0.60%
95%	0.70%
100%	0.80%
105%	0.90%
110%	1.00%

Plan, Exhibit IX-2.

Following the BETP Review, the Companies revised the incentive structure to include additional components. Together, the proposed incentives could still produce a maximum equity return adder of 1.00%, as shown below:

- Reduction in incentive for conversions achieved to 0.70% per the following schedule:

CumulativeConversions	Returnon Equity PerformanceIncentiv
85%	0.35%
90%	0.42%
100%	0.56%
105%	0.63%
110%	0.70%

- Establishment of a maximum 0.20% incentive for the installation of higher efficiency boilers/furnaces as a percentage of total conversions, per the following schedule:

% of High Efficiency Installations	Returnon Equity PerformanceIncentiv
15%	0.05%
20%	0.10%
25%	0.15%
30%	0.20%

- 0.10% incentive in each year that an SER is not required to be charged to existing customers, after applying non-firm margin credits.

Companies' July 26, 2013 letter to the BETP.

The financial impact of a 100 basis point adder to equity return grows over the period during which the Plan will operate. Yankee would experience a growth in return from about $200,000 in 2014 to approximately $5 million by 2023. CNG and Southern will separately grow returns from about $100,000 each in 2014 to approximately $1 million in 2019 for CNG, and to about $2 million for Southern by 2023. Late Filed Exhibit No. 1.

The Companies cited the CES in support of their proposal to provide an equity-return based performance incentive. In particular, the statement "Incentives for the state's gas companies to ramp-up the required construction quickly, which the BETP estimates will translate into as many as 7000 jobs." CES Executive Summary at V. The CES makes no further mention of incentives for the Companies' shareholders, instead recommending customer incentives for promoting energy efficiency and for choosing gas as an energy option.

The Companies stated that the Plan's equity return incentive ties directly to key CES objectives. Companies Brief, p. 16. It calls for the maximum 100 basis point increase equity return, which would accrue at levels up to the maximum, based on performance against the three metrics listed above. Plan, Exhibit IX, p. 108; Companies' July 26, 2013 Letter to the BETP, pp. 9-10. A measurement against each metric and resulting return adders would be independent. In other words, there is not a requirement for a threshold level of performance against all three (or some other metric) to be met before any incentive can be paid. The Companies will permit annual review of performance against the existing metrics and of the continuing validity of those metrics as time passes and experience is gained under the Plan. The metrics triggering added equity returns could be changed after three years. BETP Brief, p. 17. The Companies proposed no corresponding equity return reductions should performance fall below specified minimum levels.

The Companies supportedtheir equity incentive proposal by citing the use of equity incentives by Federal Energy Regulatory Commission (FERC) for transmission infrastructure investment and by state utility regulators to encourage investment in areas such as energy efficiency, electricity generation, and distribution and natural gas infrastructure.

The BETP asserted that meeting conversion goals requires no equity incentive, because the Companies will already have derived financial benefit from the additional revenues attained due to expansion. BETP Brief, p. 17. The BETP observed that incentives must focus on more than meeting expansion goals. Specifically, the BETP stated that incentives need to encourage keeping customer rates low and to promote high-efficiency furnace installation and other efficiency measures (citing insulation) to be accomplished at conversion. Id., p. 5. The BETPalso recommended two changes to the Companies proposed equity incentive structure. First, the BETP seeks a tighter connection between conversions and the energy efficiencies they will produce. Second, the BETP would change the Companies' proposed rate increase metric to provide the following equity return changes based on annual rate changes:

- Adder of 0.20% should there be no need for an SER.
- No adder or reduction for a rate increase of between 0 and 2%.
- Reduction of 0.10% for a rate increase of 2 and 4%.
- Reduction of 0.20% for a rate increase of more than 4%.

Id., pp. 18 and 19.

The OCC considers the benefits that the Companies will receive from customer growth and infrastructure expansion to provide sufficient incentives, thus rendering an added return on equity unnecessary. OCC Brief, pp. 24 and 25. The OCC observed that the Plan's cost/revenue reconciliation through the proposed SER provision will ensure a return on rate base. The OCC also expressed concern about the ability to set effective benchmarks for earning incentives, observing that the Plan's execution faces uncertainties likely to require revisions, as experience with customer decisions grows. Should the Authority find an equity "bonus" proper, the OCC recommended that the existence of an SER of no more than zero should act as a firm trigger to its accrual. The OCC suggests this trigger to prevent the accrual of incentives with a positive SER, because it would mean higher costs or lower revenues than anticipated. Id. The OCC recommended that any incentive accrual also require achievement of at least 100% of annual goals, observing that the Companies proposed a lower trigger of 85%. Plan, Exhibit IX-1. The OCC contended that the BETP's proposed incentives for high-efficiency furnace installations can best be addressed as part of the goals under the Companies energy efficiency programs. OCC Brief, pp. 24 and 25.

The AG recommended rejecting the added equity return proposal, stating that the Plan already serves their financial interests. AG Brief, p. 1. The AG considers the financial incentives to the Companies sufficiently strong without further incentive. The addition of paying customers and the growth in rate base on which they can earn a return form the foundation for this conclusion. The AG further stated that the proposed incentives could actually induce uneconomic expansion by encouraging the understatement of costs and the overstatement of revenues. AG Brief, p. 7. The AG noted that the absence of incentive provisions for the Companies in the Act and the protection against revenue loss provided by Conn. Gen. Stat. §16-19tt, as amended by the Act to decouple distribution revenues from sales volumes. AG Brief, p. 9.

The CES discussed the incentives in the context of "ramping up" resources, which is an early stage process under the Plan. The Authority finds that the annual cost/revenue reconciliation and the changes in Hurdle Rate application will prove sufficient to induce the Companies to engage in a ramping up process with diligence and dispatch. The SER reconciliation process proposed by the Plan already provides an incentive for the Companies, because they address the potential for regulatory lag on incorporating investments into rate base, and operate essentially to ensure that the Companies will earn the full allowed return on prudent expenditures. In theory, the Authority contends that adopting incentives related to cost control and improved efficiency have merit, but has a number of concerns with the proposed mechanisms in this proceeding.

The first issue with the proposed incentives involves allocation of resources. If a gas company activity qualifies for an incentive while other activity does not, there is a risk that savings on that work will be offset by added costs on other work. The incentive to apply better resources and project management to incentivized work to make it more efficient can mean lowered efficiency on other, non-incentivized work, which is then performed by less capable resources under less focused project management. Where this is the case, shareholders can gain while customers will not, or even experience harm, should the next base rate case incorporate higher costs for the non-incentivized work.

The second issue with the proposed incentives involves cost allocations. To the extent that there is flexibility in how costs (the significant overheads applicable to design and construction work for example) are allocated among projects, the Authority questions the wisdom of creating two categories of costs, one subject to incentives while the other is not. Incentives should produce economies not only in targeted areas, but overall. Great care needs to be taken not just in crafting incentives, but in providing for controls, transparency, and auditability of costs. It is not clear how these needs will be met. The first two issues apply not only to positive (return adder) incentives, but to negative (return reductions) ones as well.

The third issue with the proposed incentives is that their supporters appear to accept implicitly their particular applicability to Plan work. The Authority does not find that it is proper to leap past the question of the role that incentives should play in rate regulation more generally. The statute, as the AG appropriately notes, does not require their application under the Plan. Moreover, even the CES addresses them only in the context of Plan ramp-up, which the Authority is already sufficiently incentivizing through Hurdle Rate modifications and the annual SER reconciliation. Commencing such a broadly applicable use of return incentives, considering the vast expansion of rate base that successful Plan implementation will produce, should not occur before sound, comprehensive consideration of their merits and risks more generally. Secondarily, experience in the first years of Plan’s implementation will provide a much sounder basis for determining whether and to what extent positive and negative incentives are needed to support expansion and are appropriate in light of the need to manage Plan rate impacts properly.

The fourth issue with proposed incentives concerns their interplay with rate-of-return considerations in base rate cases, which will continue as the Plan operates. It cannot be said that there exists one and only one single rate of return that is appropriate for a utility. In the rate-setting context, it is more instructive to consider reasonable returns as a range, with a specific number to be established after consideration of a variety of contributing factors. Some of those factors prove more objective and readily quantifiable than others. Within the range of reasonable outcomes, some factors might point more toward the lower end, while others may suggest movement in the other direction.

For these reasons, the Authority rejects the Companies' utility incentives as proposed in the Plan, but remains open to reconsideration if they believe an incentive could effectively drive the overall performance with a focus on tangible cost savings or other efficiencies. See,Section II.B.9.Process Review / Cost Reduction Strategy. Any proposed incentive should include a threshold basis, for example: meeting or exceeding certain quality targets or meeting or exceeding the objectives of the DIMP Program.The Authority offers the following suggested goals:

1. reduction in the averagecost per installation;
2. reduction in the averagecost per mile of main installed; and
3. reduction in the averageO&M cost per customer.

The Companies may file a new incentive proposal in a reopener of this proceeding and/or a general rate case proceeding, depending how they structuretheir respective incentives (ROE based or otherwise).

F. ANNUAL RECONCILIATION FILING

1. Reporting Requirements

As indicated by the Act, on or before June 15, 2014, and annually thereafter, the Companies must report to the BETP and the Authority of their status and progress of the Plan implementation. The report should include at a minimum the following:

1. the number of customers added for the prior year by type of conversion and by customer class;
2. a comparison of actual to estimated expenditures for the previous year;
3. a forecast of the new number of customers and expenditures expected for the following year; and
4. any additional information that the BETP or the Authority deems appropriate.

As part of this reporting requirement, the Companies have proposed to make an annual reconciliation filing on October 1 that consists of actual data for 8 months (January – August) along with a four-month forecast (September – December). Plan, pp. 107 and 108. According to the Companies, any new rates from this reconciliation would be implemented on January 1, and would include, but not be limited to the following exhibits:

1. a reconciliation of the prior year's expenditures plus estimate of four months of the current Plan period;
2. the annual revenue requirement forecast for the upcoming year;
3. a calculation of SER (if needed);
4. a calculation of SE rate changes (if any);
5. a calculation of NFM offsets;
6. a residential conversion credit calculation;

7. a performance incentive calculation;
8. a re-evaluation trigger assessment; and
9. details of large project expansions, inclusive of any projects that have been analyzed using the "societal benefits" analysis from the DECD.[8]

The Authority finds the reporting components identified by the Companies appropriate for inclusion in the annual reconciliation filing. In addition, the Authority will direct the Companies to include the following supplemental components identified by the OCC in that filing:

1. The number of customer, load and potential revenues added by rate class for the previous year and plan-to-date, segregated into the following categories:
   a. low use conversions;
   b. on-main;
   c. off-Main, segregated by geographic project area and consolidated total that includes the initial year of conversion, actual number of conversions, and a remaining forecast of future conversions; and
   d. a comparison of these components to the initial Plan estimates.
2. The costs for Item 1 above segregated by mains, services, and meters.[9]
3. The bill impacts by rate class SER and DIMP.[10]
4. The customer backlog segregated by contractor and HVAC partner.
5. The oil/gas price spread by month for the most recent 12 months.[11]
6. The number and amount of any rebates used.
7. The number of contractor crews under contract for the current year and for future years for both main expansion and main replacement as compared to the number of crews necessary to achieve the Plan along with any crews delayed or canceled due to limited resources.
8. A study within the context of each company's next rate case that compares the incremental revenues andgas consumption used in the Hurdle Rate

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8 Response to Interrogatory OCC-62.

9 The Authority will require inclusion of distribution system reinforcements.

10 Because the SER is a reconciliation mechanism, it is not a satisfactory indicator of the bill impact. Therefore, the Authority will require an exhibit that shows the change in revenue requirement on an annual and cumulative basis, rate revenues and the net revenue excess or deficiency. The change in revenue requirements shall then be allocated to the firm rate classes using the class allocation factors approved in each company's most recent rate-case and then allocated on a volumetric or demand basis to determine the rate impact. This rate impact shall then be applied to an "average customer" within each rate class to determine the average "bill impact" for each rate class. The impact of the redirected NFM should be added in a manner deemed fit by the Companies.

11 The Companies should report the oil/gas spread both from company records and as reported by the EIA.

model to justify new customers added with the actual incremental usage of those customers.

Bachelder PFT, pp. 30 and 31.

Finally, the Authority will require the Companies to identify any reinforcement / reliability projects in progress and provide a list of expansion / replacement projects, which were delayed or canceled due to limited resources.

The BETPrecommended that that the Companies should establish an ongoing reporting system so the Companies, the BETP and the Authority can monitor the status of the program on an ongoing basis. BETP Review, p. 9. The Authority agrees and will direct the Companies to make continuing annual filings on the progress of the Plan, including the information items detailed above along with its SER reconciliation. As part of this annual filing, all other elements of the annual reconciliation filing as proposed by the Companies in the Plan are hereby approved. The Companies may implement the SER concurrent with the March 1 filing, subject to change after approval by the Authority.

The Authority notes that the minimum filing requirements noted above will need to be filed in accordance with the Act, but notes that the additional filing requirements should be provided on March 1, 2015 and annually thereafter, along with their SER request.

2. Re-evaluation Triggers

The Companies proposed a set of re-evaluation triggers in the Plan to determine if changes to the Plan are necessary should unforeseen circumstances arise such as: (1) a re-convergence of natural gas and oil prices; (2) if market conditions do not materialize; or (3) if the rate impact to existing customers from the Plan becomes unduly burdensome. Plan, p. 7. Specifically, the proposed triggers are as follows:

1. **Material change in the gas/oil price spread**: The spread between oil and gas prices declines to a level such that, after factoring in the premium paid by new customers under the SE rates, “burner tip” gas prices are more than delivered oil prices. Such forecast convergence of gas and oil prices must be reasonably forecast to be the expected future state for a period of more than two years as forecast by the U.S. Energy Information Administration.

2. **Material impact on existing customers**: The SER for a given year is set at a level that, all other things equal increase a residential customer’s average annual distribution bill by more than 25%.

3. **Failure of prospective customers to convert to natural gas**: The actual numbers of customers converted, on a cumulative basis, are

> less than 50% of the customers forecasted to convert for that same time period, as established in the preceding year's review of the Plan.

Plan, p. 22.

The BETP suggested triggers such as a 50% reduction in the oil/gas spread a 10% increase in distribution rates and 20% fewer conversions than planned would be more appropriate. BETP Review, p. 9. The Companies agreed to those triggers noting that should any of these triggers be reached, the Companies will evaluate the impact of these changed circumstances and propose adjustments to the Plan to mitigate their impact.Companies Joint July 26, 2013 Letter to BETP.

The AG emphasized the need for the Authority to carefully review the proposed re-evaluation triggers. The Plan should be re-evaluated if: (1) the gas/oil spread falls by 30% to 40% rather than 50% for a period of more than 6 months; (2) the SER increases an average customer's overall rate by more than 3% instead of the 10% suggested; and (3) the actual number of customer conversions is less than 50% of the number forecasted rather than the 20% proposed by the Companies. AG Brief, pp. 13-15.

The Authority finds the proposed evaluation triggers acceptable with the following additional trigger. The Companies will be directed to notify the Authority if the totality of the Plan expenditures increases the overallaverage residential bill for existing customers by 5% or more in any given year or by 15% or more over the life of the plan[12].

III. FINDINGS OF FACT

1. The Companies filed a Plan on June 14, 2013, with both the Commissioner of the DEEP and the Authority.

2. The Plan aims to convert approximately 280,000 customers in total to natural gas over a 10-year period.

3. The Companies' overall plan is to achieve approximately 85,000 new off-main customer additions.

4. For ratemaking purposes, a customer is defined as a meter.

5. The availability of sufficient numbers of capable resources for the Plan's execution was the subject of much concern by the Parties in the proceeding.

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[12] "Life of the Plan" is intended to reflect the 10-year period January 1, 2014 through December 31, 2023.

6. The Plan contemplates a vast expansion in the rate of Connecticut customer additions over the coming three to five years at the same time that many Northeast gas companies face, what has been described to be major repair, replacement, and extension needs.

7. Many of the gas expansion financing programs are still in the development/approval phase and as such, represent a “work in progress.”

8. The portfolio of financing programs currently appears to be heavily dependent on ratepayer funding, rather than leveraging private capital.

9. The success of the Plan depends on customer behavior.

10. The Companies did not present a quantified set of goals in their marketing strategy.

11. The cost of a limited conversion“credit” of up to $250to aggregate customer demand for a project is easily justified by the savings generated.

12. There are particular supply constraints that have limited the Companies’ ability to add customers in certain portions of their service territories.

13. Expansion of the LNG plants connected to CNG and Southern systems can serve most parts of their service territory through displacement.

14. The per unit cost of the new capacity assets will be considerably higher than the per unit cost of the Companies’ current capacity assets.

15. Managing gas capacity is a difficult and often uncertain undertaking, which will likely be more so during the proposed gas expansion plan where there is the expectation that a large amount of new capacity will be needed over a relatively short period of time.

16. Capacity additions are lumpy, not normally matching the need at the time.

17. The Companies have vast experience effectively managing their gas capacity portfolios.

18. The incremental expansion projects selected by the Companies only move gas from specific interconnections to their city gate stations and do not move gas from the upstream supply points to the interconnections associated with the selected projects.

19. The Companies intend to purchase commodity at the respective delivery points shown in the Precedent Agreements from a supplier(s) of natural gas.

20. The receipt points associated with the Precedent Agreements have relatively few pipeline interconnects with Marcellus supply sources.

21. The receipt points for the respective Precedent Agreements may not be liquid supply points.

22. Marcellus supplies have been priced lower than other supply sources.

23. The Companies will not buy incremental supplies at Marcellus-based prices under the Precedent Agreements currently configured.

24. At this time, one of the receipt points shown in a Precedent Agreement does not have a direct interconnect with Marcellus supplies and the Companies would be dependent on future pipeline projects that would connect to the receipt point along with supplies that have been transported to that point.

25. Capacity additions typically involve entering into long-term service contracts.

26. Yankee's large customers can opt to take interruptible service or leave its distribution system.

27. The Companies are confident that they will be able to meet their peak-day supply obligations and deal with contingencies that arise.

28. The contracts associated with the Precedent Agreements carry a substantial cost, which would be $1 billion over a 15-year period.

29. The Companies reserve primary firm capacity on the interstate pipelines from multiple supply sources, to meet their firm customers design peak day demands.

30. The design peak day is defined as the coldest day in the last 30 years.

31. Electric generators typically have not purchased pipeline capacity to a supply source and purchase commodity gas supply in the secondary interruptible market.

32. This secondary interruptible market only exists when primary firm pipeline contracts are not fully required to meet firm customers daily demands.

33. Since the interstate pipelines are designed to meet firm customers design peak day demands, no gas shortage occurred during the winter of 2012 / 2013 in the New England market.

34. The owners of the generators are susceptible to the price fluctuations and availability of commodity in the New England market.

35. New pipeline projects will have an impact on supply patterns, and thus on prices and basis differentials.

36. Under current rulings, the Companies would offset the increased cost of gas to customers by using 99% of the annual NFMs.

37. Ratepayers are at risk for all of the costs associated with the incremental capacity when it enters service in 2016.

38. Focusing expansion efforts in areas of older infrastructure creates the potential toreduce methane leakage by replacing older leak-prone infrastructure, increase safety and reliability by modernizing the system, and reduce costs.

39. The Companies' systemshave old distribution infrastructure, such as cast iron and bare steel piping.

40. The only significant way to reduce the threat of cast iron and bare steel pipe leaks is through replacement.

41. The expansion of the natural gas infrastructure contemplated in the Plan will necessitate an increase in the workforce that is involved with designing and constructing said infrastructure.

42. The same workforce that is involved with the replacement of leak-prone piping is involved with expansion.

43. It will take several years for the Companies' ratepayers to be made whole on a given project, if at all.

44. The Plan's goal to add approximately 280,000 new customers in the next 10 years, on average approximately 28,000 a year, is significantly greater than normal growth.

45. Process approaches vary among the Companies.

46. One of the hardest risks to asses under the Plan is the Companies' ability to acquirethe remaining 40% of revenues for a given project that it is discounting under the Hurdle Rate model.

47. The Hurdle Rate is a financial analysis used by the Companies to determine whether a new customer can be economically served and the revenues collected over a period of time will recover the capital investment.

48. A Hurdle Rate seeks to provide reasonable assurances to the Companies that the revenues expected to be produced by the new customer will exceed costs,

including a return of and on investment (measured over a predetermined time period).

49. When a specific project does not pass the Hurdle Rate analysis, the Companies must secure a CIAC designed to reduce investment to a level that would satisfy the test.

50. An on-main customer is defined as having an existing main that is directly in front of their premises and an off-main customer is defined as requiring an addition of a main in the street to connect them.

51. Eliminating the Hurdle Rate requirements for on-main residential customers would make the administrative process of connecting a potential new customer more efficient and reduce the amount of a sales representatives' time when marketing service to potential new customers.

52. The use of the 60% customer commitment prior to a project being built does not mean that revenues will equal 60% since each customer can have different usage.

53. Yankee has not conducted an internal audit of the Hurdle Rate model and/or its input data in the past 10 years.

54. Yankee did perform a Post Mortem Report on load and capital cost estimates where the annual consumption estimates were uniformly higher than the actuals and the capital cost estimates were typically lower than the actuals.

55. The CNG and Southern 2011 Lost Load Study showed residential load overestimated by 43% and C&I by 32%, for a total of 35%.

56. For all of the CNG and Southern studies and internal audit reports, the load is consistently overestimated by as much as 43%.

57. Some amount of variation between the Hurdle Rate estimates and actual costs, sales and revenue forecasts can and will occur.

58. The societal Hurdle Rate is specifically related to those projects that are important to the state but do not pass the Hurdle Rate analysis.

59. There is no requirement in the Act that a separate societal Hurdle Rate model be designed.

60. The 20% of additional revenue included in the Societal Benefit Hurdle Rate would be paid by existing ratepayers through the SER.

61. The use of an infrastructure expansion tracker reflects a growing trend in utility rate-making.

62. Traditional rate-making practices do not do not provide rate relief as timelyas trackers do in the face of rapid increases in revenue requirements occasioned by fast-paced system expansion.

63. The 30% premium increase to new average residential customers on the SE Rate increases the payback period from 5.4 years to 6.2 years for both CNG and Southern customers.

64. C&I customers' annual savings with a 30% premium yields a rather small loss of savings and minimally increased payback periods.

65. On-main customers are more economical than off-main customer additions and would require a lower SE premium.

66. A 10-year term for the SE Rate further mitigates potential rate increases to existing gas customers.

67. Redirecting NFM credits from the PGA to offset gas expansion costs will increase gas bills for all customers.

68. Between rate cases, the Companies defer capital investments in new business for recovery in the next rate case, where the Authority would review them for prudency, used and usefulness and allow recovery on these investments.

69. Ignoring potential decoupling impacts, revenues from new customer growth can help offset the Companies expenses between rate cases.

70. The implementation of an SER will allow the Companies to reconcile gas-expansion related revenue requirements and revenues annually in between rate cases.

71. The Act requires that incremental revenues from new customers added pursuant to the Plan be included to offset expansion costs.

72. Working capital generally represents the additional funding required to bridge the gap between the time that bills are rendered and the time that they are paid.

73. The working capital component of rate base is traditionally included in the revenue requirement calculation for each rate case.

74. A reconciliation mechanism will change the timing of how the Companies will receive rate relief.

75. The Authority is required to review costs for inclusion in the SER under existing statutory and constitutional ratemaking principles.

76. The Companies have authorized depreciation schedules from their last general rate case.

77. The return of- and on- incremental capital investments, personnel, O&M, taxes, interest expenses and uncollectable expenses are included in the revenue requirements calculation.

78. The Companies will not retain additional revenues from the Plan to offset incremental O&M incurred between rate cases.

79. The financial impact of a 100 basis point adder to equity return grows over the period during which the Plan will operate.

80. Utility incentives for Plan activity are not required under the Act.

81. The incentive to apply better resources and project management to incentivized work to make it more efficient can mean lowered efficiency on other, non-incentivized work, which is then performed by less capable resources under less focused project management and shareholders can gain while customers will not, or even experience harm.

82. Commencing a broadly applicable use of return incentives, considering the vast expansion of rate base that successful Plan implementation will produce, should not occur before sound, comprehensive consideration of their merits and risks more generally.

83. Experience in the first years of Plan's implementation will provide a much sounder basis for determining whether and to what extent positive and negative incentives are needed to support expansion and are appropriate in light of the need to manage Plan rate impacts properly.

84. In the rate-setting context, regulatory commissions typically consider a range of reasonable returns, with a specific number being established after consideration of a variety of contributing factors.

IV. CONCLUSION AND ORDERS

A. CONCLUSION

Pursuant to the directives of the Act, the Authority herein approves a regulatory model for the Companies to implement in their effort to convert approximately 280,000 customers in total to natural gas over a 10-year period pursuant to the Act and the CES. Specifically, the Authority approves changes to the Hurdle Rate model the Companies use, allows the implementation of new rate mechanisms and reassigns NFM credits to offset the costs of expansion. The Authority approves a reconciliation process herein and sets forth new reporting requirements, which will allow the Parties to review the progress of the Plan during the annual SER filings. Each company shall ensure that replacement projects are given priority over expansion projects if there are not sufficient resources for both programs.

The Authority imposed a number of monthly and annual compliance filings in the instant Decision, which include Order Nos. 9, 11, 14, 16, 17, 19, and 21. The Companies shall jointly request a reopening of the instant docket with their first compliance filing and continue making their respective compliance filings in the reopener up to and including the first SER filing. The Companies shall follow this procedure each subsequent year for the life of the Plan.

B. ORDERS

For the following Orders, submit one original of the required documentation to the Executive Secretary, 10 Franklin Square, New Britain, Connecticut 06051 and file an electronic version through the PURA's website at www.ct.gov/pura. Submissions filed in compliance with the Authority's Orders must be identified by all three of the following: Docket Number, Title and Order Number.

1. By November 26, 2013, the Companies shall submit a filing that shows whether the proposed capacity plan remains valid based on the changes made by this Decision as discussed in Section II.B.6.Capacity Plan.

2. No later than December 6, 2013, each gas company shall file with the Authority for approval their respective proposed tariffs in accordance with the instant Decision either in an outstanding rate case or in a limited reopener of their last rate case, which the company shall request upon filing. Rider DG shall also be updated to reflect that the SER is subject to rebate.

3. No later than December 15, 2013, the Companies shall submit to the Authority for approval revisions, if any, to the proposed capacity plan as discussed in Section II.B.6.Capacity Plan.

4. No later than January 2, 2014, each company shall file with the Authority,a cost conversion calculator, as discussed in Section II.B.4. Marketing Plan, and present this material to prospective customers upon approval.

5. No later thanJanuary 2, 2014, each company shall file with the Authority an exhibit confirming that O&M expenses are included in their respective Hurdle Rate models.

6. No later than January 2, 2014, each company shall submit to the Authority for approval a proposed internal auditing plan designed to monitor and compare the

estimated costs, sales and revenues used in the Hurdle Rate analysis to the actuals.

7. No later than January 2, 2014, each company shall inform the Authority that it has hired a professional auditor or an outside consultant to review and audit the Hurdle Rate estimation inaccuracies as discussed in Section II.C.3.e. Inaccurate Estimates in the Hurdle Rate, and when the audit is completed, file the final report including recommendations.

8. Effective January 2, 2014,for the life of the Plan, each company shall assign NFM credits in accordance with the directives in Section II.D.2. Assignment of Non-firm Margin Credits.

9. Effective January 2, 2014, each company shall notify the Authority if any of the re-evaluation trigger events discussed in Section II.F.2.Re-evaluation Triggers occur.

10. No later than January 10, 2014, each company shall provide a proposed cost conversion calculator in accordance with the directives in II.B.2. Marketing Plan, and make this form available to all potential customers upon approval.

11. No later than February 1, 2014, and monthly thereafter for the life of the Plan, each company shall submit a filing to the Authority that includes the original Hurdle Rate summary page associated with each off-main portfolio view / project that the company began construction on during the previous month as discussed in Section III.C.3.e. Inaccurate Estimates in the Hurdle Rate.

12. No later than March 1, 2014, each company shall develop and submit to the Authority for approval, a methodology for assigning NFM credits to offset the costs for projects deemed to have societal benefits, as discussed in Section II.D.2.Assignment of Non-firm Margin Credits.

13. No later than March 7, 2014, the Companies shall provide a joint proposal on the development of a Process Review Approach,as discussed in Section II.B.2.Process Review / Cost Reduction Strategy.

14. No later than March 7, 2014, and annually thereafter for the life of the Plan, each company shall present a detailed resource plan to the Authority for approval, as discussed in Section II.B.3.Resource Adequacy.

15. No later than July 1, 2014, each company shall submit quantified marketing results goals, each of which sets forth a suitable range of outcomes, as discussed in Section II.B.5.Marketing Plan.

16. No later than January 2, 2015, and annually thereafter for the life of the Plan, each company shall file with the Authority annual reports to address on a

categorical level the costs per installation for extensions in each of the nine listed categories in Item two as discussed in Section II.C.3.a. 150-Foot Residential Service Extension.

17. No later than March 1, 2015, and annually thereafter, each company shall submitto the Authority for approval its respective SER filing that includes:

    a. the directives in Section II.D.3.Infrastructure Expansion Tracker / SER;
    b. all of the reporting requirements outlined in Section II.F.1. Reporting Requirements;
    c. a report of the NFM margin credits generated and where the credits will be applied;and
    d. customer counts by both meter and end-user; and
    e. identify incremental O&M expenditures by account number and identify whether these expenditures were included in the Hurdle Rate model as discussed in Section II. D.3.a.iii. Operations and Maintenance Expenses.

18. No later than June 1, 2016, and every two years thereafter for the life of the Plan, each company shall revisit and provide to the Authority a copy of an enhanced financing strategy, as discussed in Section II.B.4.Financing Plan.

19. The Companies shall notify the Authority if the totality of the Plan expenditures increases the overall average residential bill for existing customers by 5% or more in any given year or by 15% or more over the life of the plan.

20. If Yankee intends seeks to procure firm capacity based in large part to its intent to provide firm service tocustomers cited in the protected response to Interrogatory EN-10, Yankee shall confirm that it has secured firm service contracts for a minimum of three years with these customers and provide the Authority copies of the contracts.

21. A year after the metered gas flow for each portfolio view project has begun, each company shall submit as part of the appropriate SER true-up proceeding: (a) a new Hurdle Rate Summary page using the actual cost, sales and revenues; and (b) a working excel spreadsheet comparing the original Hurdle Rate estimates to the actual data for the project, as discussed in Section III.C.3.e. Inaccurate Estimates in the Hurdle Rate.

22. Each company shall ensure that replacement projects are given priority over expansion projects if there are not sufficient resources for both programs.

DOCKET NO. 13-06-02 PURA INVESTIGATION OF CONNECTICUT'S LOCAL DISTRIBUTION COMPANIES' PROPOSED EXPANSION PLANS TO COMPLY WITH CONNECTICUT'S COMPREHENSIVE ENERGY STRATEGY

This Decision is adopted by the following Commissioners:

John W. Betkoski, III

Arthur H. House

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Public Utilities Regulatory Authority, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Nicholas E. Neeley

Nicholas E. Neeley
Acting Executive Secretary
Public Utilities Regulatory Authority

November 22, 2013
Date