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December 6, 2013

Via Email
Original via Mail

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130, Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively the Companies)

Applications for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Applications)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 2 on PBR Methodology

Filed as Response to FEI-FBC CEC IR No. 3

On June 10 and July 5, 2013, FEI and FBC, respectively, filed the Applications as referenced above.

In an effort to differentiate the IR responses relating to the PBR Methodology which are the subject of the oral portion of the hearing jointly for the Companies from those IR responses which relate to other matters for the written portion of the hearing individually for each of FEI and FBC, the Companies will mark these IR responses as FEI-FBC CEC IR No. 3.

The Companies respectfully submit the attached response to FEI-FBC CEC IR No. 3 responses related to the PBR Methodology.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC. and
FORTISBC INC.

Original signed:

Diane Roy and Dennis Swanson

Attachments

cc: Commission Secretary
Registered Parties (email only)

I. PBR PRINCIPLES

1. Reference: FEI Exhibit B1-1, Appendix D1, Page 2 and Exhibit B1, Page 43

> **Principle 1:** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2:** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3:** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4:** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5:** Customers and the regulated companies should share the benefits of a PBR plan.

> **Principle 1:** The PBR plan should, to the greatest extent possible, align the interests of customers and the Utility; customers and the utility should share in the benefits of the PBR plan.
>
> **Principle 2:** The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3:** The PBR plan should recognize the unique circumstances of the Company that are relevant to the PBR design.
>
> **Principle 4:** The PBR plan should maintain the utility's focus on maintaining, safe, reliable natural gas service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.
>
> **Principle 5:** The PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

1.1 Do FEI and FBC agree with the AUC Principle 1: A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality?

Response:

This response addresses FEI-FBC CEC PBR IRs 3 1.1 and 3 1.1.1.

FEI and FBC agree with AUC Principle 1 that a PBR plan should, to the greatest extent possible, encourage efficiency while maintaining service quality. FEI and FBC believe the proposed PBR plans satisfy this principle as well as each of the other Principles submitted.

A regulated environment is fundamentally different from a competitive environment, so the Companies do not necessarily agree with the AUC's reference to a competitive market. Please see the response to FEI-FBC CEC PBR IR 3.9.2 to 3.9.5 and 3.40.2 in this regard.

1.1.1 If not, please explain why not.

<u>Response:</u>

Please refer to the response to FEI-FBC CEC PBR IR 3.1.1.

2. Reference: FEI Exhibit B-8, CEC 1.31.2

> PBR Plans by their nature involve forecasts and the one thing we know for certain is that forecasts will be wrong. The question then becomes not whether the Plan could be improved but whether the Plan is the best Plan available given the state of the art and the necessary assumptions that underlie the Plan methodologies. In that case, the Plan could not be improved as it represents the best available information and analysis. Given the prior FEI and BCUC experience with successful PBR Plans, it seems reasonable to conclude that the changes from prior plans represent positive improvements for this Plan and continue the portions of prior Plans that resulted in successful outcomes.

2.1 Please confirm that, although needing to be flexible, the best PBR plan is one that addresses the most likely situation under which it will be operating, rather than an historical situation.

Response:

The PBR Plan should be realistic and provide the utility with a reasonable opportunity to earn its allowed return under the expectations of normal circumstances while also providing adjustments for unforeseen changes and costs beyond the reasonable control of management. Further as indicated in Principle 3 of the PBR Applications the PBR Plans should be easy to understand, implement and administer. In this context, FEI and FBC believe that their historical plans achieve this objective, by virtue of being familiar and well-understood.

FEI and FBC have modified the historical Plans for those areas where the Companies perceive there is a reason to adjust the Plans (to reflect the most likely scenario). Otherwise, the Plan components continue to be appropriate in the current context.

2.2 Please provide FEI's and FBC's forecast of major changes that might be reasonably expected to occur during the PBR period such as the proposed amalgamation and the introduction of postage stamp rates.

Response:

FEI and FBC anticipate that major changes that might reasonably be expected to occur during the PBR Period would generally be subject to either a separate regulatory application (such as a CPCN) or would be treated as an exogenous factor within the PBR mechanism.

FEI has discussed major planned CPCN projects in FEI's Application (Exhibit B-1), Section C4.7 and FBC has discussed major planned CPCN projects in FBC's Application (Exhibit B-1), Section C5.7.

FEI and FBC cannot speculate as to which specific exogenous factors may arise during the term of the PBR but note the following types of items are included in its proposal:

- Judicial, legislative or administrative changes, orders or directions;
- Catastrophic events;
- Bypass or similar events;
- Major seismic incident;
- Acts of war, terrorism or violence;
- Changes in GAAP, standards or policies; and
- Changes in revenue requirements due to Commission decisions (examples include rate design issues, depreciation rate changes, changes to cost of capital).

For a discussion of the FEU's proposed amalgamation and the introduction of postage stamp rates, please refer to the response to FEI-FBC CEC PBR IR 3.2.3.

2.3 Please discuss how amalgamation and the introduction of postage stamp rates can be expected to impact the financial results of the PBR plan if they are undertaken during the PBR period.

Response:

If the FEU receive approval to amalgamate and implement postage stamp rates, it will be effective January 1, 2015 such that delivery rate requests for 2014 will not be affected.

For 2015 through 2018, FEI would propose to include the newly amalgamated entity in the approved PBR mechanism. This would mean that O&M and capital expenditures for FEVI and FEW for 2014 would be added to FEI's 2014 formula base, and then be subject to the same formula mechanism for 2015 through 2018. Other items not subject to the formula (demand forecast, other revenue, property taxes, depreciation, income taxes, interest expense, deferral account balances, etc.) would be forecast on an amalgamated entity basis, with amalgamated comparatives provided for prior periods to provide comparability. The approved amalgamated ROE would be used to determine both the return on equity and the earnings sharing amounts on a go forward basis.

2.4 Do FEI and FBC consider that there were any negative consequences from the past PBR plan relative to what might have occurred under a Cost of Service plan?

Response:

No, the PBR plans delivered demonstrable benefits for both customers and the Utilities, and provided regular meaningful engagement opportunities in which customers were informed of results and given opportunities to provide feedback. These were accomplished while maintaining customer service levels. Please refer also to the response to FEI-FBC CEC PBR IR 3.2.6.

2.4.1 If yes, please explain what types of negative consequences emerged as well as any 'lessons learned' that FEI or FBC has identified.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.2.4.

2.5 Would FEI and FBC agree that the effects of changes to capital and operations management in utilities related to gas and electricity are frequently long term in nature?

Response:

Yes.

2.5.1 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.2.5.

2.6 Would FEI and FBC agree that evaluation of a PBR plan requires historical analysis to ensure that savings generated were not perversely creating a situation of ‘short term gain for long term cost or service decline’ such as may be associated with slow erosion of customer satisfaction, or delayed and non-optimal deployment of capital resources etc.?

Response:

FBC and FEI agree that the experience under past plans is relevant in terms of whether the plans created sufficient incentive for the utility to generate benefits for customers and the Company. The past plans accomplished this objective in the sense that there were considerable earnings shared with customers without degradation of service, and thus were used as the basis for designing the proposed Plans.

However, it is not productive in this proceeding to micro-manage the past results (i.e. pass judgment on individual actions taken in the past) when rebasing has occurred and the Commission has already determined in the case of FEI coming out of PBR that the past plan (which is the basis for the present Plan) was beneficial to customers.

2.6.1 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.2.6.

2.6.2 Is so, over what period of time would FEI and FBC believe that an historical review of the PBR plan should take place to determine its successfulness. Please explain with justification.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.2.6. FEI and FBC would generally expect the evaluation of the success of the PBR to come in the regulatory period or periods following the PBR. This was done in FEI's case in both the 2010/2011 and 2012/2013 RRAs. Continuing to revisit and dissect the prior PBR results again and again is inefficient, costly and unnecessary.

2.7 Please provide a complete list of criteria, with explanations, by which the Commission and interveners including rate payers and organizations related to environmental concerns can judge the results of the past PBR and the proposed PBR plan.

Response:

As described in FEI's Application (Exhibit B-1), Section B2.1 PBR Benefits, the two most commonly cited benefits of a PBR plan are its effectiveness in incenting the utility to capture efficiencies, and regulatory efficiency. FEI believes it has delivered both these benefits in its past PBR plan while maintaining service quality, and the Commission has commented favourably on the outcome of the plan. The Company refers to its success to provide the criteria by which the Commission and interveners including rate payers can judge the results of the past PBR plan and the proposed PBR plan.

- As noted in the Application (Exhibit B-1), Section B4-2 FEI 2004 PBR Experience, FEI was able to successfully achieve significant savings and benefits for both customers and the Company. The benefits were achieved in three ways – through the productivity improvement factor, through the O&M savings, and through the capital savings. For details, please refer to page 37 of FEI's Application (Exhibit B-1). Further, FEI was able to achieve these savings over the six year PBR period without degradation in the quality of service provided to natural gas customers.
- Regarding regulatory efficiency, the 2004 PBR plan provided a longer term framework in which the utility operated without frequent, costly and time consuming revenue requirement applications. FEI also met other requirements in the PBR plan to be open

and transparent in conducting its business. This included conducting Annual Reviews and Customer Advisory Council meetings as set out in the PBR, and responding to the issues and concerns raised by customers and Interveners in those settings.

The proposed PBR Plan builds on the successes of the 2004 PBR Plan, with some adjustments to enhance a customer focus, further promote FEI‟s productivity improvement culture and to ensure a continued focus on maintaining a high level of service quality during the term of the PBR plan. As a result, FEI believes the same criteria used to gauge success for the past PBR is applicable for the proposed PBR plan.

Regarding the interests of organizations related to environmental concerns, the proposed PBR should be neutral on environmental issues. First, EEC expenditures are outside of the formula and are thus going to continue to be pursued in the same manner as before. Second, while there are no environmental related measures included as part of the proposed suite of SQIs, there are environmental legislation and regulatory constructs in place and FEI is committed to operating in a responsible manner. FEI has an excellent compliance history concerning environmental issues. This is the result of its proactive and cooperative approach in working with the applicable regulatory authorities in meeting requirements. Additionally, the Company uses its robust Environmental Management System to track and mitigate emerging and existing environmental concerns and works with the Operations group to ensure environmental requirements are incorporated into their operational activities.

3. Reference: FEI Exhibit B-8, CEC 1.8.3 and FortisBC, Exhibit B-9, BCMEU 1.2

<u>Response:</u>

As indicated in Exhibit B-1 Section A3.1 Productivity Focus, FEI has already been pursuing a number of productivity initiatives and opportunities in recent years. Going forward, the Company expects to continue to evaluate opportunities depending on the circumstances and potential benefits to customers. The fundamental difference under PBR relates to the opportunity to invest in incremental efficiency programs that may not seem to be in the best interests of both customers and shareholder under cost of service regulation. Another way of looking at the effect of PBR is that, rather than fundamentally changing the way the Company approaches productivity initiatives, PBR creates new opportunities because it changes the cost benefit analysis for incremental initiatives that might not otherwise be practical under cost of service.

That said, there are inherent characteristics of cost of service ratemaking that limit the extent to which efficiencies can be captured. Notably, PBR extends the period before rebasing and provides for sharing of a portion of savings before rebasing, creating an opportunity for the utility to invest in incremental efficiency initiatives that may not otherwise be cost effective for the Company to undertake if rebasing were to occur immediately. PBR thus provides the incentive to actively seek out *incremental* efficiencies. Please refer to the responses to CEC IRs 1.2.2 and 1.24.3.

3.1 Please describe all examples from the past 10 year period in which potential, incremental efficiency opportunities were considered by company management but not undertaken because rebasing was to occur too soon to be cost effective for the company.

<u>Response:</u>

The Companies do not have specific examples of such opportunities in the previous PBR Periods, since both have been operating under PBR Plans since the mid-1990s, with the exception of a limited number of years under Cost of Service regulation for the purpose of rebasing prior to entering the next generation of PBR. Therefore the Companies, for the most part, have been able to see the benefits of their productivity initiatives realized during the term of the PBR Plans.

In any event, the requested exercise would be impractical because the departments considering such efficiency opportunities would not have tracked the costs separately in order to evaluate the potential impacts of rebasing.

However the inability of the utility to realize the benefits of a productivity initiative while operating outside of a PBR regime can be illustrated in the example of FBC's proposed Asset Management strategy set forward in its 2012 – 2013 Revenue Requirements application. FBC requested funding to develop an Asset Management program aimed at optimizing its plant maintenance, which would benefit both capital expenditures and O&M Expense in future. This development work was described as incremental to the Company's existing workload, and that the asset management strategy would result in the development of processes and implementation of software to provide benefits in subsequent years.[1]

The Asset Management strategy, which would not have yielded efficiencies during the 2012-2013 test period, was not approved in FBC's Cost of Service decision. Had the Company been operating under a longer-term PBR Plan, this type of expenditure may well have been undertaken, either as O&M Expense, or if appropriate as a capital expenditure, with the expectation of realizing benefits over a number of years in the future.

In the case of FEI, although not in the last 10 years, in the 1998-2001 PBR the Company did provide a calculation showing that the Utility did not break even on its restructuring investment until the 4th year (FEI Exhibit B-1, page 34). Without the 1 year extension FEI would not have broken even. This example further demonstrates the benefits of the longer time horizons provided by PBR to implement efficiency measures.

3.2 For each example please identify how the opportunity was brought to management attention and whether or not a business case was developed for the opportunity.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.3.1.

3.2.1 If business cases were developed please provide the business case for each opportunity.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.3.1.

[1] G-110-12, page 64 of Decision

3.2.2 If business cases were not developed, please provide a description of the opportunity, the expected costs and projected benefits and the years in which they were expected to occur.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.3.1.

3.3 Please indicate for each case example whether or not the companies in the next revenue requirements proceeding undertook the efficiency improvement and if not why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.3.1.

3.4 For each example please provide a cost/benefit analysis and calculate the financial impacts that would have occurred for shareholders and ratepayers has a PBR process been in place versus a cost of service process.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.3.1.

II. FIVE YEAR TERM

4. Reference: FEI Exhibit B-1, Page 45

> First, the five-year term addresses a key objective regarding regulatory efficiency as the term minimizes the frequency of comprehensive revenue requirement applications.
>
> Second, this five year period provides an adequate amount of time for FEI to attain cost savings from capital investments and other efficiency initiatives. These types of investments generally require a few years for the benefits to be realized. An example of this can be seen in FEI's experience (noted above) in the 1998-2001 PBR where break-even on the efficiency investment did not occur until the fourth and last year of the plan. In addition, the proposed Efficiency Carry-over Mechanism (discussed below) will provide incentive for FEI to continue pursuing efficiency gains throughout the PBR term for the long term benefit of customers.
>
> The perceived challenges associated with a longer PBR term relate to risk to customers and the utility, as well as regulatory transparency. The potential risks of a longer term PBR for either the utility or its customers are typically mitigated through other plan provisions such as exogenous factors, re-openers or off-ramps. There are checks and balances implicit in the proposed PBR Plan, discussed below, which mitigate risk to either customers or the Company in the context of a five-year term. Moreover, FEI proposes an annual review (and mid-term review) of Company performance as a means of maintaining transparency. The achieved efficiencies, service quality measure results, earnings sharing results, and the off-ramp mechanism (if necessary) will be reviewed in that context and will provide regular opportunities during the term to assess the success of the PBR Plan.

4.1 Please give examples with quantification of capital investments or efficiency initiatives that require more than four years to break even.

Response:

FEI and FBC do not have specific examples of capital investments or efficiency initiatives that take more than four years to break even. The process of identifying such incremental initiatives is part and parcel of a PBR.

Conceptually, the ongoing savings from the efficiency initiatives need to offset and exceed the revenue requirement increases caused by the increased O&M expenses or capital investment required to undertake the initiative. In general FEI and FBC will tend to pursue the efficiency initiatives with shorter breakeven periods to maximize the benefits of the PBR Plan for customers and the utility; however, the five-year proposed PBR term will expand the array of possible opportunities and enable initiatives that take four years to pay back to be pursued.

4.1.1 For each example please describe whether or not, and how, FEI or FBC could seek and receive approval to undertake such an investment or efficiency initiative under cost of service ratemaking.

Response:

In cost-of-service ratemaking the review of capital investments for efficiency initiatives would typically take place within the review of overall capital expenditure budgets, generally in a revenue requirement application. The review of capital projects typically takes place at the functional (or departmental) level, i.e. transmission, distribution, IT, finance & administration, etc. Many capital projects have drivers that are not efficiency-related, such as complying with regulations or maintaining system integrity and reliability. The review of large projects with expected efficiency benefits, which would likely be dealt with through CPCN applications, would normally examine the proposed project benefits in terms of revenues generated or O&M savings, and follow up would be done in later regulatory processes to confirm the benefits have been incorporated in rates. With smaller projects that may produce efficiencies, the business cases may be considered in the regulatory approval process but, since there are many small projects, it becomes extremely difficult very quickly to trace the costs and benefits within the overall revenue requirements. Thus the regulatory review process may approve the efficiency-related projects with the best business cases but verification that the planned efficiencies have actually been achieved would be next to impossible. FEI and FBC believe that a prescriptive top-down approach for efficiency-related capital projects as might be required in a cost-of-service framework would be unwieldy and impractical. In contrast the flexibility within PBR to pursue efficiency initiatives as they are discovered, together with the continuing influence of shareholder discipline, will bring about the successful achievement of efficiencies without the complex artificial framework that would be needed in a cost-of-service environment.

4.2 Please contrast the cost of service bi annual comprehensive revenue requirement applications and the PBR annual review and Mid-term process with respect to degree of openness and transparency, provided to the Commission and Interveners, into the FEI and FBC operations?

Response:

Comprehensive bi-annual reviews of revenue requirements examine the components of the utility's revenue requirements in greater detail. These processes also consume a great deal of time and resources for utility personnel, the Commission and interveners, and are very costly for customers. The annual reviews should be less involved than a traditional rate hearing; otherwise the efficiency benefit of PBR is reduced.

That does not mean that the PBR process as a whole is less transparent, because the annual review is only one consideration. The PBR Plan lends itself to a less onerous review process because it involves a transparent formula that de-links the utility's costs from revenues. All stakeholders will know what the expectation is going into the PBR in terms of the Companies seeking out savings, and the results if they identify those savings. All stakeholders know the expectation regarding rebasing at the conclusion of the period.

In that context FEI and FBC believe the Annual Review process and other engagement processes in their PBR Plans are appropriate for their intended purpose.

4.3 Please compare the cost of service process of 'rebasing' with each revenue requirements process versus the 5 year PBR term under formula, with respect to the 'no rebasing' risk undertaken if the formula proves to be more generous than would have occurred under a 2 year cost of service revenue requirements process.

Response:

The Companies do not understand what is being referred to as "no rebasing" risk. If the question is asking about the risk to customers with a longer plan on the assumption that the plan is poorly calibrated, there would be more risk with a longer plan. (The same risk exists for the utility.) However, the Companies consider the proposal to be well calibrated. Moreover, the risk associated with a longer period before rebasing comes with the potential for considerable additional benefit. The premise of PBR is to encourage the utility to seek out incremental efficiencies that will yield benefits for both customers and the utility, and a longer term is integral to achieving that objective. The PBR would produce superior results in the longer term by providing the utility with a known quantity of benefit for 5 years in total (ESM and ECM) so more efficiencies would be achieved. Under two year cost-of-service revenue requirements the prospect of rebasing in a short period of time would be a hindrance to some of these initiatives being undertaken.

5. Reference: FEI Exhibit B-1, Page 45

"While there are reasons for selecting both shorter and longer periods, it seems that a five year period has become the most common period for review of PBR plans. From a theoretical view, the period must be long enough to permit the utility to earn the expected return on new cost saving technologies and not so long as to permit significant gains or losses for stakeholders. For a well developed plan that includes appropriate plan elements to preserve the fundamental regulatory compact for all stakeholders the five year period seems to be appropriate. The length of the plan must be set in conjunction with off-ramps and reopeners that protect all stakeholders. Further, the plan incentives must be symmetric and reasonable as will be discussed below. Shorter plans have a larger regulatory burden than longer plans in terms of the rate reset frequency. Longer plans have potentially lower regulatory costs but greater uncertainty of outcomes for stakeholders. The five year plan seems to be reasonable so long as other portions of the plan are reasonable."

5.1 Please confirm that FEI and FBC will not be at risk of not earning a return on its equity investment in new technologies, provided that it does not invest in capital over and above the formula projected amount of capital.

Response:

This statement cannot be confirmed. Recognizing that equity return is a residual concept, other factors may result in under recovery of the allowed return even if the capital investment is less than or equal to the formula amount.

5.2 Please confirm that FEI and FBC have some considerable control over whether or not they spend the capital over a 5 year PBR period.

Response:

The Companies have some control over capital spending otherwise it would be inappropriate to include capital in the PBR formula. Having said that, there are a number of reasons why capital expenditures may be above or below the formula amount even if the Company manages capital spending prudently and efficiently.

5.3 Please confirm that it is possible under a 5 year PBR to have potential capital expenditures on new cost saving technologies where the benefits to be shared would not offset the capital cost excess over the formula projected capital spending. Please describe how such a situation could occur and if FEI and FBC believe it could not occur please explain why.

Response:

There is no reason for the Companies to make an investment in cost saving technologies knowing that the cost savings will not recover the incremental capital cost on a risk adjusted basis. However, this does not mean that a project with forecast earnings that meet the hurdle for investment could not turn out to perform more poorly than forecast and consequently under-recover capital costs. That is part of the risk of PBR faced by the Companies.

5.4 Please explain how the length of the PBR process is correlated with the potential for ‘significant gains or losses’ for stakeholders, such that the length of the PBR period needs to be kept in the 5 year range and please provide examples of the kinds of problems that could occur with a PBR process that was too long.

Response:

B&V provides the following response.

There can be potential for significant gains and losses under a Plan that is poorly designed and based on a poor model. That is part of the rationale for reopener and off ramp provisions. Longer plans may produce results that do not provide a reasonable opportunity to earn the allowed return and adversely impact shareholders. Longer plans may also produce results that unjustly enrich shareholders at the expense of customers. Neither outcome is desirable.

5.5 Please provide a quantitative assessment of the avoided regulatory process benefit of 5 year PBR versus the 2 year Cost of Service and please provide a working spreadsheet should the complete evaluation of this issue.

Response:

FBC has estimated that the avoided incremental costs over the PBR term that are captured in deferral accounts, compared to cost of service regulation, could be in the range of $0.5 million to $2 million annually, depending on the timing of revenue requirement filings, and the nature and scope of the proceedings and the type of review process. FEI estimates a similar range and provides the amounts in its response to FEI CEC IR 2.75.1.1 (FEI Exhibit B-23). The increasing regulatory requirements for all types of applications are described in the response to FBC CEC IR 2.36.1 (FBC Exhibit B-25).

The Companies do not expect any reduction in O&M Expense due to avoided regulatory process, for reasons explained in the response to FEI BCUC IR 2.292 series (FEI Exhibit B-24).

Absent a PBR Plan, FEI and FBC would file either annual or biannual applications for revenue requirements during the 2014-2018 period, however the Companies are unable to state specifically the number or timing of such applications, as those decisions would necessarily be made in consideration of the circumstances facing the Companies at the time, and are therefore unable to provide the requested spreadsheet.

5.6 Please provide FEI's and FBC's interpretation of the 'fundamental regulatory compact' from both the shareholders' and the ratepayers' perspective.

Response:

The regulatory compact is a legal concept. It is embodied in section 59 of the UCA and has been spelled out at some length in the ATCO case. A simple articulation is that ratepayers have a right to obtain "reasonable, safe, adequate and fair" (UCA, s.25) service at a fair and reasonable charge, and the shareholder has a right to an opportunity to earn a fair return (UCA, section 59).

6. Reference: FEI Exhibit B-1, Page 46 and FEI Exhibit B-11, BCUC 1.3

> B&V's view is that 5 years is a reasonable plan term for FEI's PBR Plan, having regard to the other elements of FEI's proposal.
>
> FEI is willing to consider an optional extension to the plan. The main benefit of a PBR plan extension would be to enable the utility to continue to pursue efficiency gains in the targeted areas (i.e. O&M and capital expenditures) over a longer period. A plan extension option should be viewed simply as another item in the overall balance of opportunities and benefits presented by a PBR plan. Just as plan elements such as the initial term, the X-factor, exogenous factors, off-ramps, earnings sharing mechanisms and others need to be considered as an entire package, a plan extension option would be another item to consider in evaluating the overall balance of a PBR plan.
>
> The length of the extension period cannot be specified without giving consideration to any other terms and conditions associated with the extension, or to related provisions of the PBR plan.
>
> FEI believes that it is possible to develop an extension provision that would fit into the proposed PBR plan and would permit continued benefits to be achieved for customers and the utility. However it may be appropriate to consider an extension provision as part of the Mid-Term Review after actual experience with the PBR has occurred.

6.1 Please describe the nature of an optional extension to a PBR plan that FEI and FBC would be willing to consider, explaining whose option this would be how it would be invoked and what test would apply as to whether or not is would be accepted or approved and how the approval process would work.

Response:

For clarity, the Companies starting premise is that if the Plan would be extended it would require a separate Commission approval at the time of extension. The referenced question raised the idea of an option included in the original approval and asked the Companies to comment on it. While the Companies are willing to *consider* an option that is included in the initial order, they still feel that it is more practical to address the idea of an extension down the road because the type of option would affect the risk profile and value proposition of the entire plan – i.e. it should all be considered together.

The Companies' preferred approach is akin to what was done in the context of the last FEI PBR, for instance. The original approved negotiated settlement for FEI's 2004 PBR covered the four-year period from 2004 to 2007 and did not contain an optional extension provision. Even so FEI initiated discussions with stakeholders with respect to a two-year extension that were successful in reaching a Negotiated Settlement Agreement and resulted in Commission approval of a two-year extension. The two-year extension was successful in generating additional benefits for both customers and FEI. FEI and FBC believe the same thing could occur again even if there is no optional extension provision in the final approved PBR (unless the Commission's decision states otherwise.) FEI and FBC believe this could be initiated either by the Utilities, the Commission or other stakeholders.

FEI and FBC cannot comment in the abstract on the nature on an acceptable optional extension provision. This will be dependent on the final approved terms of the PBR, the PBR results-to-date at the time the option is exercised and the terms of the extension. These and other factors, such as the business conditions existing at the time, will all affect the value proposition of the extension for customers and the Utilities.

6.2 Would FEI and FBC agree that an optional extension could provide for more opportunity for incentive earnings than a fixed term? Please explain why or why not.

Response:

FEI and FBC are responding to this IR with the understanding that the question is whether there is more opportunity for incentive earnings with longer fixed terms as compared to a PBR where a fixed end date is not known.

Generally, the longer the period between rebasing of revenue requirements, and assuming the PBR Plan and utility performance under the Plan are successful, there is likely to be an opportunity for continued incentive returns and greater benefits for customers. It would provide less incentive to shorten the initial period and then make it subject to an extension because the utility would be planning based on the initial shorter period before rebasing. Regardless of length, a PBR Plan is always open for renewal should the Commission determine it is just and reasonable to extend it, but the ability to extend the period doesn't provide additional incentive during the initial period until the extension is confirmed.

6.3 Would FEI consider a three year term with an optional extension to 5 years rather than a five year initial period? Please explain why or why not.

Response:

No. Please refer to the response to FEI-FBC CEC PBR IR 3.6.2.

6.3.1 If so, please discuss the types of modifications to the PBR package that FEI and FBC deem would be necessary to make a 3 year initial term with optional extension to 5 years appropriate.

Response:

In general FEI and FBC believe the three-year initial period would not provide an adequate period of time to support the robust pursuit of longer term efficiency improvements. If the optional extension did not occur the three year term of the plan would be little more than a multi-year cost-of-service revenue requirement application. The Utilities have each had successful PBR plans that were five or more years in length so the Commission and stakeholders have had recent experience with longer term plans.

7. Reference: Exhibit B1-1 Appendix D1, Page 4

> for other PBR plans in North America. The AUC went on to state that, "although a shorter term tends to blunt the incentives for companies to identify and implement productivity improvements, the Commission has approved the inclusion of an efficiency carry-over mechanism to mitigate this effect. "[7]

7.1 Do FEI and FBC agree that the Efficiency Carry Over Mechanism mitigates a reduction in incentives that could occur under a shorter term PBR plan?

Response:

Yes. However the advantages of ECM are not limited to short-term PBR plans. The ECM addresses the reduction in incentives that would otherwise occur in the latter years of a PBR plan of any duration due to there being little time left to obtain payback on incremental investments before rebasing occurs.

As indicated in FEI-FBC joint procedural conference response to undertaking (Exhibit B-16)

> *"Implicit in incentive regulation is the notion that gains for all parties are possible if the business can be encouraged to increase the efficiency and effectiveness of its operation. However, the incentive to out-perform the predetermined benchmark may be undermined if the regulated business believes its efforts will be insufficiently rewarded and the benefits immediately returned to customers at the end of the regulatory period.* ***The shorter the regulatory period or the further into an existing regulatory period, the greater this potential disincentive****".* ***A rolling carry-over mechanism can increase the incentives of short-term PBR plans but maybe more importantly provides a regulated business with an ongoing incentive to operate efficiently throughout the entire regulatory period (regardless of the PBR term****).*

7.1.1 Please explain why or why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.7.1.

7.2 Please discuss FEI and FBC's views with regard to an optimal Cost of Service regulation period between PBR regulation periods.

Response:

It is difficult to identify a single "optimal" period. In the past, there has been a desire on behalf of stakeholders to conduct a cost of service proceeding after a period of PBR. But there is no reason in principle why this needs to occur. It is possible to continue with PBR without switching to cost of service as long as rates are periodically rebased and the PBR Plan is adjusted to reflect the reduced ability of the utility to find significant cost savings as the result of multiple PBR periods.

III. COMPARISON TO OTHER JURISDICTIONS

8. Reference: FEI Exhibit B-11, BCUC 1.1.2

The approved X-factor values for each of the five PBR plans are presented in Table 1 below:

Table 1: X-factor values and determination methodologies for each of the five PBR plans

Utility/Jurisdiction	PBR Period	Methodology	X-factor
Alberta	2013-2017	TFP (0.96%) + Stretch factor (0.2%)	0.96% + 0.2% = **1.16 %**
Union Gas	2008-2012	Negotiated Settlement (Not based on any specific study)	**1.82%**
Enbridge Gas	2008-2012	Varied based on different percentage of inflation index (GDP IPI FDD)	Varied **between 0.36% and 1.22%** (see Table 2 below)
Ontario's power distributors (3rd Generation IR)	2009-2013	TFP (0.72%) + 3 cohorts of Stretch factor (0.2%, 0.4% or 0.6%)	0.72% + (0.2%; 0.4%; 0.6%) = **(0.92%; 1.12%; 1.32%)**
Ontario's power distributors (4th Generation IR)*	2014-2018	TFP (0.1%) + 5 cohorts of Stretch factor (0 %, 0.15%, 0.30%, 0.45%, 0.6%)	0.1% + (0 %, 0.15%, 0.30%, 0.45%, 0.6%) = **(0.1%; 0.25%; 0.4%, 0.55%, 0.7%)**
Gaz Metro	2007-2012	Negotiated. (Reflective of the historical rate increases and inflation).	**0.3%**

* The TFP value calculated and proposed by the OEB's consultant (OEB has used the services of the same consultant in 3rd and 4th Generation IRs) however the X-factor value is not yet approved by the OEB.

8.1 To what extent do FEI and FBC believe that other jurisdictions X-factor determinations are or should be determinative of the FEI and FBC X factor determination?

Response:

The use of other jurisdictions' X-Factors has been discussed extensively in the filing. As a general matter, these values have limited relevance to the Commission's determination for the Companies. Some are dated and not relevant (based on negotiated settlements), some have serious methodological flaws in the determination as identified by B&V, and none of the estimates of the X-Factor reflects utilities with similar circumstances to the Companies, either gas or electric.

8.2 Would it be fair to characterize the range in X-factors being set as 600% difference between a low range of .3% and an upper range of 1.82%?

Response:

The difference between percentages is often defined in terms of percentage points or basis points to avoid ambiguity between relative and absolute values. Therefore it would be better to say that the range for X-factors among studied jurisdictions is 152 basis points.

8.3 Please explain why FEI and FBC believe such a wide range exists.

Response:

As indicated in response to FEI BCUC IR 1.6.1 (Exhibit B-11), many of these X-factor values are based on settlements and therefore it is not possible to comment on the result of any specific element used to determine the X-factor values for these Utilities. Nevertheless items such as utilities' business profiles and functions, prior level of productivity gains, the year in which the X-factor value is determined or cumulative effect of PBR elements can impact the X-factor value and lead to a range of X-factor values as illustrated in the Table 1 above.

IV. INFLATION FACTOR (I FACTOR)

9. Reference: FEI Exhibit B-8, CEC 1.34.1

> FEI disagrees with the premise of the question. Including inflationary measures allows the company to ensure its cost structure reflects economic conditions that are beyond the control of FEI and that affect businesses generally. The AUC correctly acknowledges this issue in its AUC Decision 2012-237 that the "changes in a company's input prices due to inflation are not within its ability to control, although the company may be able to use those inputs more efficiently than its competitors"[8]. Therefore there is no contradiction between pursuing the efficient improvements and minimizing the costs that are within the control of the Company and adjustment of costs for changes in input prices that are outside of its control.

9.1 Please provide the AUC Decision 2012-237.

Response:

Please refer to FEI's Application (Exhibit B-1), Appendix D9-3, titled "AUC PBR Decision 2012".

9.2 Would FEI and FBC agree with the remainder of the AUC paragraph that states that 'In competitive markets, when faced with a universal, economy wide increase in input prices (such as an increase in salaries and wages, higher fuel prices, etc.), companies are often left with no choice but to pass on these higher costs to consumers. Similarly, when the prices of inputs go down, competition in the market forces the companies to lower their prices.

Response:

B&V provides the following response.

The statement is generally correct for the competitive market. It would be more precise to say that these increases will pass through (in the form of increases in prices or decreases in quality) or the firm will fail since under the competitive model there is no economic profit to absorb the increases. The threat of new entry will force prices down whenever costs decline. None of this is relevant to utility regulation since prices are set by regulation and may or may not bear any resemblance to prices under competitive markets. Further, the existence of sunk costs makes threat of entry irrelevant for a utility absent some method to make the services associated with the utility contestable.

9.3 Please confirm that in competitive markets it is often the case that when costs rise companies are not always able to pass them through to customers and can end up needing to absorb some cost increases and improve efficiencies.

Response:

B&V provides the following response.

This cannot be confirmed under the competitive market model of economics. If the term competitive market means another theoretical market structure where the demand curve is downward sloping, then not all of the cost increases can be passed on nor do all efficiency improvements get passed on. Finally, all of the issues related to the competitive market model have nothing to do with regulation since utilities are regulated as to price and even output.

9.4 Please confirm that competitive pressures that companies face in the market place are not just related to the prices of inputs and that these prices of input do not always have the same effect on all competitors in the market.

Response:

B&V provides the following response.

The response to this question depends on the theoretical market structure model used to analyze this statement. It cannot be confirmed under pure competition. For other market models this statement is generally true but in no way applies to utilities subject to regulation because the costs would pass through as long as they are prudent.

9.5 Do FEI & FBC expect that the ‘I’ factor in the PBR plans is intended to mimic the competitive forces in the market place’? Please explain why or why not.

Response:

B&V provides the following response.

No. The I-factor only addresses changes in cost unrelated to changes in output, technology, scale and efficiency.

10. Reference: FEI Exhibit B-8, CEC 1.35.1

> 25 In addition, the selection of AWE is consistent with that of the Alberta Utilities Commission
> 26 recent decision to use AWE as a measure of labor inflation in their PBR implementation.

10.1 Why does FEI consider it relevant that the AWE is consistent with that of the Alberta Utilities Commission recent PBR decision?

Response:

By letter dated April 18, 2013, titled "Productivity Improvements in a Performance Based Rate Setting Environment", the Commission requested that FEI's examination of PBR methodologies include the most recent PBR plans employed by FortisBC Inc. and PBR methodologies approved by other jurisdictions in Canada. The recent PBR developments in Alberta, by AUC Decision 2012-237, added to the set of jurisdictional precedents that exist in Canada.

With respect to the use of the AWE index in particular, FEI agrees with the AUC, in Decision 2012-237 that the AWE Index provides a reasonable overall reflection of labour price changes facing the utility.

10.2 Do FEI and FBC view consistency with the AUC recent decision as being relevant in other aspects of the PBR decision-making process? Please explain which aspects of the PBR decision should or should not be consistent with the AUC decision and explain why.

Response:

FEI and FBC believe a PBR Plan should reflect the unique circumstances of the jurisdiction it is being applied to. The Companies' proposed PBR Plans build on the successes of past PBR plans in BC, although the design does share many common features with other plans.

It is reasonable to consider what is occurring in other jurisdictions, but the measure of whether a PBR model or particular elements of a PBR model should be adopted is whether the model or model elements improve upon the past approach used locally. FEI and FBC believe the composite I-factor approach using CPI and AWE adopted in Alberta is such an improvement that is easily accommodated within the Utilities' proposed approach to PBR. However, the Companies and B&V have identified aspects of the Alberta PBR that do not make sense (these issues have been addressed primarily by B&V in the reports filed with the Application). The

Companies would not propose to adopt such components, because they would not be an improvement to the model successfully employed here in the past.

In support of the idea that plans should be tailor made, FEI and FBC note also that there is considerable variation amongst Canadian utility PBR plans. In Ontario, for example, there has been an evolution of PBR development over the last fifteen years or so. Even with more than a decade of experience gained, the PBR plans of the two major gas utilities remain quite different from each other on many plan features. The OEB and utility stakeholders find these differences to be acceptable and the differing PBR plans are approved by the OEB.

11. Reference: FEI Exhibit B-8, CEC 1.36.1

> FEI investigated the possibility of using alternative sources of labor-related inflation other than the BC AWE. However, an alternative source that represented BC's economy-wide labor inflation is not available, and the BC AWE remains the most appropriate measure of BC labor-related inflation.

11.1 Please identify the other sources that FEI investigated other than the BC AWE, even if they did not represent BC's economy-wide labour inflation.

Response:

FEI did not investigate other sources other than BC AWE for the labour component of the composite inflation factor. Please also refer to the response to FEI-FBC CEC PBR IR 3.10.1 and FEI CEC 2.21.1 (Exhibit B-23).

11.2 What is the proportion of salaried employees to hourly employees?

Response:

FEI and FBC interpret salaried employees to mean Management & Exempt (M&E) employees, and hourly employees to mean unionized employees.

In that context, the proportion of M&E employees to unionized employees by company and overall is shown in the table below. Also shown below, and in response to FEI-FBC CEC PBR IR 3.11.3, is the proportion of base earnings (i.e. salaries/wages) attributable to M&E employees and unionized employees

Group	Utility	# of EE	% of EE	Total Base Earnings	% of Total
M&E	Electric	155		$ 14,536,657.98	
	Gas	507		$ 45,902,736.10	
M&E Total		**662**	**28.9%**	**$ 60,439,394.08**	**37.6%**
Union	Electric	336		$ 23,486,565.25	
	Gas	1289		$ 76,783,248.62	
Union Total		**1625**	**71.1%**	**$ 100,269,813.87**	**62.4%**
Grand Total		**2287**		**$ 160,709,207.95**	

This data is current to October 31, 2013, and excludes executives as well as employees on long-term disability leave and on union leave.

11.3 What is the proportion of wages attributable to salaried employees as hourly employees?

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.11.2

11.4 Please explain if salary wages and hourly wages are known to increase at the same rate, or if they differ?

Response:

This response addresses FEI-FBC CEC PBR IRs 3.11.4, 3.11.4.1 and 3.11.4.2.

The increase in salary wages and hourly wages differ from year to year. Lines 1 and 2 in the table below indicate the actual BC Average Hourly Earnings (BC-AHE) increase for Salaried Employees[2] and BC-AHE for Employees-Paid-by-the-Hour[3] from 2002 to 2012 reported by Statistics Canada. While the two inflation measures may differ from each other in a single year, over an extended period, both measures increased at a similar rate. For instance, the BC-AHE for Employees-Paid-by-the-Hour increased on average by 2.9% annually from 2002 to 2012, while BC-AHE for Salaried Employees increased on average by 2.6% annually over the same period.

Line #	AHE vs AWE Labour Inflation Comparison		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Average
1	BC	AHE For Employees Paid by the Hour	2.0%	3.1%	3.0%	3.4%	2.5%	3.9%	3.5%	1.4%	2.5%	3.8%	2.4%	2.9%
2	BC	AHE For Salaried Employees	2.5%	1.6%	2.4%	1.9%	2.8%	4.5%	3.8%	2.4%	3.0%	1.9%	1.7%	2.6%
3	**BC**	**Average AHE (Average Line 1 and Line 2)**	**2.2%**	**2.4%**	**2.7%**	**2.6%**	**2.6%**	**4.2%**	**3.7%**	**1.9%**	**2.8%**	**2.9%**	**2.0%**	**2.7%**
4	**BC**	**AWE Table 281-0027**	**2.1%**	**2.2%**	**1.7%**	**3.7%**	**2.9%**	**3.4%**	**2.6%**	**0.8%**	**3.0%**	**2.8%**	**2.9%**	**2.6%**

Moreover, when both the BC-AHE for Salaried Employees and BC-AHE for Employees-Paid-by-the-Hour are averaged together (line 3), it is comparable to the BC Average Weekly Earnings[4]

[2] Source: Statistics Canada Canism Table 281-0036
[3] Source: Statistics Canada Canism Table 281-0030
[4] Source: Statistics Canada Canism Table 281-0027

(BC-AWE) measure, which includes both salaried and hourly employees. From 2002 to 2012, the average annual increase for BC-AWE and the Average of the BC-AHE for Salaried Employees and BC-AHE for Employees-Paid-by-the-Hour was 2.6% and 2.7% respectively.

If the average is weighted by the Companies' number of union vs. M&E employees or earnings as provided in response to FEI-FBC CEC PBR IR 3.11.2, the more detailed calculation would result in a higher inflator than using the AWE metric. While the Companies would not be averse to such a modification, it would add some additional complexity to the annual calculation.

As such, the Companies maintain that the BC-AWE is the most appropriate and reasonable inflation indicator of labour for both salaried employees and employees paid by the hour for the PBR plan in keeping with the principle of being easy to understand, implement and administer.

11.4.1 If they are known to differ, please provide the sources for determining inflation related to hourly earnings and salaried earnings.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.11.4.

11.4.2 If they are known to differ please provide historic data with respect to the rate of increase for each of hourly wage earnings and salaried earnings.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.11.4

12. Reference: FEI Exhibit B-1, Page 46 and Exhibit B1-1, Appendix E

> ***6.2.2.1 Inflation Factor (I – Factor) Proposal***
>
> The use of an inflation or I-factor in a PBR plan is to provide recognition that utility costs are subject to the general inflationary pressures occurring in the economy, although the specific pressures or weightings of the various inflationary influences may be different than for the economy in general. This is one area where FEI is proposing a change from the 2004 PBR Plan. FEI's previous PBRs calculated an average inflation rate for British Columbia using a combination of sources for CPI forecasts. These forecasts were collectively referred to as the BC-CPI. FEI proposes to use instead a weighted composite I-Factor, consisting of the following inflation indexes: labour indexed to BC All Weekly Earnings (BC-AWE) and non-labour indexed to BC-CPI. FEI believes it is more appropriate to use a composite labour and non-labour inflation index in determining the I-Factor since this is more reflective of Company costs, which consist of both labour and non-labour components, than an economy-wide inflation measure such as CPI.

12.1 Please briefly describe in detail the various inflationary influences that affect the CPI and specifically comment on whether or not the CPI contains both labour and non-labour components in its basket of goods and services.

Response:

CPI contains labor components as subsumed in the prices of finished goods that make up the index. There are many different final goods and services that make up the CPI. Some have minimal labor input, others have substantial labor input albeit, except for energy related costs, not necessarily the same labor making up the utility labor costs. CPI is an estimate of inflation for these final goods and services.

12.2 Please confirm that FEI and FBC are subject to the inflation for the economy in general.

Response:

Confirmed.

12.3 Would FEI and FBC agree that non-labour inputs could be broken down into two groups including materials and services, and capital investment?

Response:

Although it may be possible to break down non-labour inputs as suggested, the components would vary by year depending on projects underway at the time. FEI and FBC believe there would be little value to pursuing this kind of analysis because it is too detailed to be applied in a reasonable manner. Further, only at the highest level is this breakdown a reasonable categorization. There are many specific items in each category and those items vary broadly based on utility accounting and include items that also include a labor component as well. Capital is also subject to variations and many of these items include a labor component and of course a materials and supplies component.

12.4 Please provide for the total of FEI and FBC non-labour components the proportion that is directly materials and equipment related and the portions that represents labour services and if FEI and FBC do not have an accounting breakdown of costs for non-labour expenses in this way please provide FEI's and FBC's best estimates.

Response:

Provided below is a table for FEI and FBC that shows the proportion of materials and equipment and labour services that are included in the 2013 Projection of non-labour O&M.

Materials and equipment include materials and supplies, vehicle costs and office furniture and equipment. Labour services include consulting and contractor costs, legal, external audit fee and cross charges between FEI and FBC.

	2013 Projection			
In Thousands	**FEI [1]**		**FBC [2]**	
Materials and Equipment	$ 10,866	11%	$ 4,134	15%
Labour Services	43,277	45%	12,526	47%
Total M & E and Labour Services included in Non-Labour	$ 54,143	57%	$ 16,660	62%
Total Other Non-Labour	$ 41,477	43%	$ 10,234	38%
Total Non-Labour	$ 95,619	100%	$ 26,894	100%

1 Excludes deferred Customer Service O&M in FEI

2 Includes data from the July 5, 2013 Filing

13. Reference: Exhibit B1-1, Appendix E, ScotiaBank forecast and BMO Canadian Economic Outlook

Quarterly Forecasts	12Q4	13Q1f	13Q2f	13Q3f	13Q4f	14Q1f	14Q2f	14Q3f	14Q4f
Consumer Prices (y/y, % change)	0.9	0.7	0.8	1.3	1.7	1.9	1.9	2.0	2.0
Core CPI (y/y % change)	1.2	1.1	1.1	1.4	1.5	1.7	1.7	1.9	1.9

May 24, 2013

	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2011	2012	2013	2014
(year/year % change)																
CPI All Items	2.3	1.6	1.2	0.9	0.9	0.8	1.2	1.3	1.3	1.8	1.9	2.0				
BoC Core	2.1	2.0	1.5	1.2	1.3	1.2	1.4	1.5	1.6	1.7	1.8	1.9	1.7	1.7	1.4	1.8

13.1 Please confirm that a Core CPI forecast removes the costs of potentially volatile indicators such as food and energy from a CPI calculation/forecast.

Response:

Confirmed. Core CPI forecasts remove the costs of volatile indicators such as food and energy from a CPI calculation/forecast

13.1.1 If not confirmed, please provide FEI's and FBC's understanding of the difference between Core CPI forecasts and CPI forecasts.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.13.1

13.2 Would FEI and FBC agree that the Core CPI may be considerably different from the CPI, and that for 2014 is generally expected to be lower than the CPI?

Response:

FEI and FBC agree that Core CPI is different than CPI, and that it is generally less variable than CPI. This is not surprising since Core CPI is developed by removing some of the more volatile components out of CPI. Core CPI is forecast to be slightly lower than CPI for 2014 but this follows 2013 where Core CPI was forecast to be slightly higher than CPI in several quarters.

13.3 Please provide any core CPI forecasts for the Province of BC of which FEI or FBC is aware.

Response:

The Companies did not consider using BC Core-CPI for use in the PBR. For that reason the Companies are not aware of any core CPI forecasts for BC except for those indicated in the question asked in CEC IR 2.22.1 (Exhibit C1-5). Please refer to the response to that CEC IR, being filed concurrently with the PBR Methodology IRs in FEI CEC IR 3a.22.1.

14. Reference: FEI Exhibit B-11, BCUC 1.4.1 and FEI Exhibit B-1-1, Appendix E1, Page 2, Table E1-2

Each of the sources listed in Table B6-2 of the Application (Toronto Dominion Bank, Royal Bank, Bank of Montreal, Canadian Imperial Bank of Commerce, Conference Board of Canada and the BC Ministry of Finance) provide updates of forecast BC CPI rates. Additionally, the Conference Board of Canada provides updated forecasts of BC Average Weekly Earnings.

Each year at the Annual Review, FEI will present updated forecasts to determine the composite inflation rate that will be utilized in the I-X mechanism for the upcoming year. FEI will not adjust previous inflation rates to the actual inflation rates. Except for the use of a composite inflation factor, the annual reforecasting of inflation for the purpose of determining the I-Factor is the same approach as was used in FEI's 2004 PBR Plan.

Table E1-2: Summary of Sources and Dates of CPI Forecasts

Source	Forecast Publish Date
Conference Board of Canada	November 2012
B.C. Ministry of Finance	February 2013
RBC Financial Group	April 2013
CIBC	January 2013
Toronto-Dominion Bank	April 2013
BMO	May 2013

14.1 How frequently are the forecasts updated for each of the sources listed?

Response:

Source	Expected Publication Frequency
Conference Board of Canada	Quarterly
B.C. Ministry of Finance	Annually
RBC Financial Group	Quarterly
CIBC	Annually
Toronto-Dominion Bank	Quarterly
BMO	Monthly

Note that the above are representative of current expected publication frequency, are potentially subject to change in the future and are not necessarily representative of the historical publication frequency. Additionally, each of the sources may provide forecasted economic information at different times; however the above table is representative of when the formal publications are expected to be made available.

14.2 Please provide the most recently updated forecasts available from each of the sources.

Response:

Please refer to the response to FEI CEC IR 3a.22.2, being filed concurrently with the PBR Methodology IRs.

14.3 Please provide the dates of when the ‘actual inflation rate’ is determined for BC CPI.

Response:

The annual BC CPI is generally published by Statistics Canada in the month after the end of the calendar year. For example, 2012 BC CPI was published by Statistics Canada at the end of January 2013.

15. Reference: FEI Exhibit B-11, BCUC 1.4.2 and FEI Exhibit B1-1, Appendix E, BMO Capital Markets, CIBC

As noted in response to BCUC IR 1.11.1, the I-X formulas affect approximately one third of the delivery revenues. Therefore a 0.25% variance between the forecast and actual I-Factor calculation would (after earnings sharing) have a net effect on the delivery rates of 1/3 x 0.25% x 50% = 0.0417%. As stated previously this small difference could be in either direction and there is no reason to believe it will be sustained into subsequent years.

Consumer Price Index

	Cda	BC
2010	1.8	1.4
2011	2.9	2.4
2012	1.5	1.1
2013 f	1.0	0.3
2014 f	1.7	1.7

	Real GDP Yr/Yr % Chg			Employment Yr/Yr % Chg			Unemployment Rate %			Housing Starts 000s Units			Consumer Price Index Yr/Yr % Chg		
	2012E	2013F	2014F	2012A	2013F	2014F	2012A	2013F	2014F	2012A	2013F	2014F	2012A	2013F	2014F
BC	2.1	1.6	2.4	1.7	0.8	1.5	6.8	6.7	6.3	27.5	22.0	21.3	1.1	0.8	1.8

15.1 The CEC would like to determine how recent the inflation forecast inputs will be relative to the time to which they will apply. Please identify when the forecasts will have been determined for each input to the composite I factor (all CPI inputs and AWE) that will be used for calculations each year and when the formula updates will occur for each year of the PBR period.

Response:

The CPI and AWE forecast assumptions will be determined as part of the Annual Review process, which is expected to take place later in the third quarter or fourth quarter of the year preceding the year for which revenue requirements will be established. As such, FEI and FBC will be providing the most recently available CPI and AWE forecasts, based on the source publication frequency provided in the response to FEI-FBC CEC PBR IR 3.14.1 that are available at the time of the Annual Review.

While the CPI forecasts are provided from several sources, AWE forecasts are only provided by the Conference Board of Canada (CBOC), which is expected to be generally published on a quarterly basis. The CBOC publications are often issued in July which is relatively close to the expected time of the Annual Reviews. To summarize, FBC and FEI will provide the most recent available CPI and AWE forecast information available at the time of the Annual Review.

This practice of using the most recent forecasts at the time of the Annual Reviews is consistent with the timing of forecasting such inputs in FEI and FBC's previous PBR frameworks, whereby forecasts are necessary to be established at a point in time in order to implement revenue requirements and customer rates before January 1. Variances, in either direction, between actual and forecast inflationary assumptions are normal forecasting occurrences that are created by external economic factors beyond the Companies' control.

15.2 For each inflation factor estimation source FEI and FBC plan to use please provide a 10 year history of the source's forecasts and the subsequent actual results for the inflation indices they were forecasting, such that the forecasting record is evident. Please provide this in a tabular format in a working spreadsheet.

Response:

Table has been provided below, and Attachment 15.2 is the working Excel spreadsheet.

Note that FEI provided a forecasted 2003 BC CPI figure that was not explicitly linked to a publication source in its revenue requirement application. Additionally both FEI and FBC did not include forecasts of BC Average Weekly Earnings (BC AWE) explicitly in revenue requirements applications for the last ten years and therefore such forecasts have not been provided and designated as not available (NA).

Similarly, FBC provided a forecasted 2005 BC CPI figure that was not explicitly linked to a publication source in its revenue requirement application, and did not forecast CPI in its 2006 application.

FortisBC Energy Inc.	BC Consumer Price Index (CPI)						BC Average Weekly Earnings (AWE)	
	Forecast					Actual	Forecast	Actual
	Conference Board Canada	BC Ministry of Finance	RBC	TD	Average BC CPI	Stat Can BC CPI	Average BC AWE	Stat Can BC AWE
2003	NA	NA	NA	NA	1.90%	2.20%	NA	2.3%
2004	1.70%	2.20%	1.50%	1.50%	1.70%	2.00%	NA	0.4%
2005	2.10%	1.90%	2.00%	2.00%	2.00%	2.00%	NA	2.6%
2006	2.00%	2.00%	2.90%	1.90%	2.20%	1.70%	NA	3.0%
2007	1.90%	2.10%	2.30%	1.80%	2.00%	1.80%	NA	2.9%
2008	1.90%	2.00%	2.30%	2.00%	2.10%	2.10%	NA	4.1%
2009	2.50%	2.00%	1.50%	1.70%	1.90%	0.00%	NA	2.6%
2010	2.27%	2.20%	1.50%	1.60%	1.90%	1.30%	NA	3.1%
2011	2.05%	2.10%	1.80%	2.00%	2.00%	2.40%	NA	1.8%
2012	2.16%	2.00%	1.80%	2.00%	2.00%	1.10%	NA	2.0%

FortisBC Inc.	BC Consumer Price Index (CPI)						BC Average Weekly Earnings (AWE)	
	Forecast					Actual	Forecast	Actual
	Conference Board Canada	BC Ministry of Finance	RBC/BMO	TD	Average BC CPI	Stat Can BC CPI	Average BC AWE	Stat Can BC AWE
2003	NA	2.00%	NA	NA	2.00%	2.20%	NA	2.3%
2004	NA	1.60%	NA	NA	1.60%	2.00%	NA	0.4%
2005	NA	NA	NA	NA	1.90%	2.00%	NA	2.6%
2006	NA	NA	NA	NA	NA	1.70%	NA	3.0%
2007	1.90%	2.10%	2.30%	1.70%	2.00%	1.80%	NA	2.9%
2008	2.00%	2.00%	2.10%	2.00%	2.00%	2.10%	NA	4.1%
2009	2.50%	2.10%	1.50%	1.70%	2.00%	0.00%	NA	2.6%
2010	2.60%	2.10%	NA	1.50%	2.10%	1.30%	NA	3.1%
2011	2.80%	2.30%	2.00%	2.10%	2.30%	2.40%	NA	1.8%
2012	2.20%	2.10%	2.10%	1.70%	2.00%	1.10%	NA	2.0%

15.3 Would FEI and FBC agree that a continued over-estimation of the inflation forecast relative to the actual inflation would result in sustained benefit to FEI and FBC? Please explain why or why not.

Response:

There is no reason to expect that there will be continued over-estimation of the inflation forecast; however, even if circumstances did result in the cumulative change in the forecast CPI-BC and AWE factors over the five year PBR period coming in higher than the cumulative change in the actual CPI-BC and AWE this does not somehow represent an inappropriate benefit to the Utilities. FEI has explained in the response to FEI-FBC BCUC PBR IR 3.6.3 that the inflationary pressures it faces are more driven by the inflation forecasts than actual inflation. With this in mind adjusting the forecast inflation levels to lower actual inflation levels would be providing a backward looking benefit to ratepayers. In terms of whether this issue would give rise to a sustained cost or benefit, any impact would be subject to 50/50 earnings sharing and would only remain until the next rebasing and residual ECM effects have lapsed.

15.4 Please confirm that some jurisdictions, such as AUC rely on a past actual inflation figure for the 'I' factor rather than a forecast of inflation.

Response:

The AUC approved the use of actual inflation rates for the most recent 12-month period to calculate the I-Factor for the upcoming year with no subsequent true-up.

15.4.1 Please identify all such jurisdictions of which FEI and FBC are aware that do so.

Response:

FEI, FBC and B&V have not looked for this specific information, so are not presently aware of any other jurisdictions.

15.4.2 Would FEI and FBC agree that such an approach automatically provides for a 'true up' to actual inflation, although it incorporates a lag? Please explain why or why not.

Response:

Although the use of actual inflation rates for the most recent 12-month period to calculate the I-Factor for the upcoming year may reference actual inflation on a lagged basis, FEI and FBC do not agree that this is the appropriate way to set the I-factor. The AUC approach is saying in effect that the actual inflation for the recent 12-month period used is a proxy for the expected cost inflation to be faced by a utility in the coming period. This is analogous to cost-of-service regulation using a historical test year rather than a future test year. In periods of low inflation the differences may not be large but FEI and FBC believe the proposed approach to inflation in their respective PBR plans is theoretically sound.

15.5 Please identify all the jurisdictions of which FEI and FBC are aware that include a forecast of Inflation for the 'I' factor with no subsequent true up.

Response:

FEI, FBC and B&V have not looked for this specific information, so are not presently aware of any jurisdictions.

16. Reference: FEI Exhibit B-11, BCUC 1.4.3

> 4.3 What is the difference in terms of the effect on the company's revenues if the inflation factor is trued up or not trued up?
>
> **Response:**
>
> An updated forecast of both BC-CPI and AWE will be presented each year at the Annual Review to ensure that the I-Factor utilized in the I-X mechanism is representative of market conditions and will provide a forecast that is as current and accurate as possible. FEI has every reason to believe that the independent third party forecasts utilized in the I-Factor calculation will be reasonable. While there may be small variations from year to year in revenues, either positive or negative, arising from differences in the forecast and actual I-Factor results, there is no basis to say that not trueing up to actual will cause any net effect on FEI's revenues over the term of the PBR.

16.1 Please confirm, or otherwise explain, that 'truing up' would result in more accurate results than not 'truing up' particularly in the event of forecasts that were consistently inaccurate in one direction or another from year to year.

Response:

Adjusting for actual CPI-BC or AWE results in some fashion would mean that the I-factor more closely tracks these measures over the term of the PBR. However adjusting these measures to actual would not necessarily mean a more accurate assessment of the cost inflation pressures faced by FEI or FBC. Please refer to the response to FEI-FBC PBR BCUC PBR IR 3.6.3.

16.2 Would FEI or FBC have any objections to annually 'truing up' inflation rates?

Response:

Yes. Please refer to the response to FEI-FBC CEC PBR IR 3.16.2.1.

16.2.1 If so, please explain why 'not truing up' is preferable to 'truing up' the I-Factor results in FEI's and FBC's view.

Response:

FEI and FBC do not believe adjusting CPI-BC and AWE to actual is appropriate. Please refer to the response to FEI-FBC PBR BCUC PBR IR 3.6.3. In addition, adjusting CPI-BC and AWE to actual in some fashion would add an additional complication into the administration of PBR formulas with no expected benefits as a result.

16.3 Please describe a process that could be undertaken by FBC and FEI to true up the I-factor every year so that the companies and rate payers were neither benefiting nor losing based on the differential between forecast interest rates and actual interest rates.

Response:

The Companies interpret CEC's question as referring to "inflation rates" and not "interest rates" as stated in the question. The Companies believe an adjustment in the sense of truing up the past year's inflation would not be appropriate. Please refer to the response to FEI-FBC BCUC PBR IR 3.6.3.

17. Reference: FEI Exhibit B-8, CEC 1.30.1 and CEC 1.30.2

> CIBC and BMO are both Canadian Chartered Banks that provide economic forecasts, specifically in this case, of the BC CPI. FEI evaluates its forecasting methodologies each year and adjusts them if it is determined that an improvement can be made. Since the goal of the forecast is to obtain the best possible estimate of the BC CPI, then adding more credible data points to the analysis is an improvement to the estimation process.
>
> Response:
>
> No, Table B6-2 includes all forecasts contemplated in calculating the forecast BC CPI.

17.1 Please provide a list of other credible organizations that provide forecasts of the BC CPI, and provide an explanation as to why FEI/FBC did not include these forecasts in their average.

Response:

Pursuant to the provisions of the FEI 2004-2007 and FEI 2009-2009 Settlement Agreements, the Commission by Order G-51-03 and G-33-07 determined that the applicable BC-CPI inflation rate was to be determined as the average of the forecasts from the Conference Board of Canada and the BC Ministry of Finance, and from two of the top 5 financial institutions in Canada: RBC Financial Group and Toronto-Dominion Bank.

To increase the precision of an average BC-CPI Inflation Forecast and in maintaining consistency with the provisions set out in Order G-51-03 and G-33-08, FEI and FBC in their Applications included forecasts from two additional 'top 5' financial institutions in Canada: the Bank of Montreal and the Canadian Imperial Bank of Commerce. FEI and FBC believe that the forecast provided based on reputable industry sources is a reasonable overall reflection of BC-CPI. For that reason, FEI/FBC did not include any other BC-CPI forecasts in its calculation of the average BC-CPI for its respective PBR Plans.

V. TFP AND X FACTOR

18. Reference: FEI Exhibit B8, CEC 1.25.1 and 1.25.2

> The quoted section assumes that the industry average TFP is measuring the performance of costs and that FEI finds efficiencies that allow the Company to be more productive than the industry average. It further assumes that the elements of the PBR Plan taken as a whole provide FEI with a reasonable opportunity to earn the allowed return throughout the regulatory control period. It further assumes that the costs associated with the operation of the plan are

> B&V has addressed this issue, in part, in the responses to BCUC IRs 1.5.1, 1.21.2 and 1.21.3. Also, earning above the allowed return with performance above the industry average may or may not occur since the formula I-X only reflects the cost side of the earnings equation.

18.1 Please clarify why the ‘industry average’ is the appropriate benchmark in comparison to other industry metrics, such as the industry ‘median’.

<u>Response:</u>

B&V provides the following response.

The industry average is a measure of central tendency and hence represents considerations of all of the differences across the entire sample.

18.2 Please clarify why FBC and FEI would not be expected to be in the top half of company performance for improving productivity or in the top quartile.

<u>Response:</u>

It is likely that the Companies would be among the most efficient utilities based on their long history of PBR.

B&V adds that this fact would suggest that productivity improvement will be more difficult as opportunities decline as the number of PBR periods increase. This is all the more reason to conclude that the 0.5 percent X-Factor is a significant stretch for the Companies.

18.3 Please confirm that utilizing the 'industry average' productivity changes as a basis for the X factor in no way reflects the status of the individual organization as being efficient or inefficient as of the starting point for determining productivity.

Response:

B&V provides the following response.

Correct. The X-Factor is not a measure of efficiency.

18.4 Please confirm or otherwise explain that utilizing the industry average as a productivity target is to reflect the long term industry trends in productivity.

Response:

B&V provides the following response.

The industry average as a productivity target is designed to reflect the trend in productivity that might be reasonably expected during the regulatory control period otherwise the factor would be inconsistent with allowing the utility a reasonable opportunity to earn its allowed return. This is the case for a number of reasons but includes sunk costs and the fact that long-term productivity estimates may be biased upward as the result of technological changes that have been fully incorporated in the industry and thus no longer available to increase productivity.

18.5 Please provide the results of other studies which purport to reflect the long term industry trends.

Response:

The question is overly broad and cannot be answered as stated.

18.6 Please provide the FBC and FEI 10 year historical total productivity factor performance.

Response:

Neither the Companies, nor B&V, have conducted such a study or even explored whether there is sufficient data available to conduct a similar TFP study. Performing a TFP study for FBC and FEI would be a significant undertaking and would have a significant cost associated with it. Given that the proposed TFP is based on an external value so as to decouple revenues from costs, this information would not be of any assistance.

19. Reference: Exhibit B1-1 Appendix D1, page 27

> The data base consists of 95 utilities operating in 30 states in the U.S. for the period 2007 through 2011. This period represents the latest available five (5) year period for the data. The utilities cover a broad range of sizes with customers served ranging from 86 for Brainard Gas in Ohio to 5,549,399 for Southern California Gas Company. The companies have varied operating histories including companies that have been in existence for over 150 years to companies that have been in existence for less than 20 years. There is also a mix of utilities that require transmission main and those that do not. Pacific Gas and Electric Company has 5,744 miles of transmission main while a number of utilities have none.

19.1 Please confirm that the 'industry average' has been derived primarily from American companies which have been historically operating under a cost of service regulatory regime.

Response:

Correct. The reasons for this have been explained in the TFP reports in the FEI and FBC Applications, Appendices D-2, page 8.

19.1.1 If not, please provide a description of the type of regulatory regime that is common to the companies from which the database was derived.

Response:

Please refer the response to FEI-FBC CEC PBR IR 3.19.1.

19.2 Please confirm that the data base is more reflective of short term industry trends rather than long term industry trends.

Response:

B&V provides the following response.

Not confirmed. There are a number of long-term trends in new technologies that are fully reflected in the TFP trends in the analysis. These include such trends as directional drilling, live main insertions, joint trenching and so forth all of which represent mature technologies that are incorporated in the TFP results.

19.2.1 Why did B&V select the 2007 to 2011 time period?

Response:

This was the most recent data available as explained elsewhere in our responses. Refer to the responses to FEI BCUC IRs 1.8.1, 1.8.2 and 1.32.2 (Exhibit B-11).

19.2.1.1 If information for a longer period of time was available, why did B&V not utilize it?

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.19.2.1

19.3 Please provide the FEI and FBC's productivity compared to the industry average over the 2007 to 2011 time period.

Response:

The requested information is not available for the reasons indicated in the response to FEI-FBC CEC PBR IR 3.18.6.

VI. CONTROLLABLE EXPENSES O&M (I-X)

20. Reference: FEI Exhibit B-1, Page 21

> The inclusion of a productivity improvement factor in FEI's PBR Plan provides a comprehensive productivity measurement that will require each department to consider continuous improvement, which is preferred to measurement of individual activity. Departments have a requirement to maintain or increase their outputs and activity levels while keeping cost increases below inflation on a per customer basis, which will result in a measured improvement in productivity. The result of this focus is evident and discussed in the departmental results and forecasts included in Section C3 of this Application and in the Productivity Focus and Organizational Performance discussion above that contains many actual examples of productivity achievements. FEI will continue to discuss productivity measures taken during the PBR Period at its Annual Reviews.

20.1 Please advise whether or not FEI and FBC have been providing each department within the company external productivity benchmarks for the last 5 years and whether or not each department has been and is expected to consider continuous improvement.

<u>Response:</u>

FEI and FBC believe productivity improvements and their sustainment should be measured and tracked by the companies' total O&M and capital spending year-over-year. While overall benchmarking may occur at the company level using high level metrics such as O&M per customer, departments are not provided external productivity benchmarks to use. Instead, to ensure funding levels are appropriate, departments are asked to undertake a detailed review of their funding requirements as part of the annual budget process.

Continuous improvement has been and is an ongoing focus for the Companies. Employees are encouraged to improve productivity and realize efficiencies to more effectively manage rates for customers while maintaining a customer service focus. In some years, this may translate into broader and more visible initiatives such as the Integration of FBC and FEI. In other years, the efforts and activities are more contained within the departments and less visible across the Companies. Whether operating under a PBR Plan or Cost of Service regulation, FEI and FBC have maintained their focus on achieving efficiencies. This is evidenced by the fact FEI and FBC have identified sustainable O&M savings of approximately $14 million and $0.4 million respectively compared to the 2013 Approved while operating in absence of a PBR agreement.

While the type of regulatory arrangements (i.e. cost of service or PBR Plan) have not affected FEI and FBC's continuous focus on productivity, as indicated in the FBC and FEI Applications (Exhibit B-1), a PBR Plan can improve the dynamic efficiency of the utility if the PBR term is long enough to encourage the cost-reducing innovations and investments that bring long-term efficiency gains that otherwise would not be undertaken while operating under a shorter Cost of Service test period.

20.2 Please confirm that this process for PBR represents no difference for the FEI and FBC departments in terms of management methodology from the past

Response:

FEI and FBC interpret the reference to "this process for PBR represents" in the preamble as meaning productivity focused or the inclusion of a productivity improvement factor like that included in the proposed PBR Plan.

As discussed in the response to FEI-FBC CEC PBR IR 3.20.1, continuous improvement or productivity focus has been and is an ongoing focus for the Companies. Whether operating under a PBR Plan or Cost of Service agreement, FEI and FBC have maintained their focus on productivity and achieving efficiencies. As discussed in that response, the longer term of a PBR does provide advantages in terms of investments that lead to greater productivity gains. In addition, it is expected that PBR will result in the avoidance of some incremental regulatory process costs which are typically deferred and flow through to customer rates. Such a cost avoidance provides additional benefits to customers.

20.2.1 If not please explain why and what the differences are and when any of the differences have changed in the past.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.20.1.

21. Reference: FEI Exhibit B-8, CEC 1.14.1

> Please note the reference to introduction of a Shared Services cost allocation approach is only in regards to the choice of the cost allocation approach (i.e. timesheet allocation approach vs. shared services cost allocation approach based on use of selected cost drivers) . Therefore, any potential savings opportunity regarding the implementation of the Shared Services agreement would be limited to only the administrative and accounting costs associated with administering the agreement, which would be immaterial (i.e. less than $10 thousand for labour to administer the agreements).

21.1 Please confirm that FEI expects additional integration savings from an amalgamation with FEVI and FEW.

Response:

Confirmed.

In FEU's Common Rates Amalgamation Reconsideration G26-13 Final Argument, FEU summarize the expected savings from amalgamation of the gas utilities. This is provided below for ease of reference.

> The FEU have estimated the benefits of amalgamation and postage stamp rates to be in the range of $901,000 to $3,128,000 per year, depending on the average short-term debt that would be applicable to the FEVI service area. *In addition*, the FEU identified other regulatory savings due to streamlined filings and applications under an amalgamated entity with one unified regulatory structure and a harmonized tariff. As the FEU noted, these savings would extend to intervenor and Commission cost savings due to fewer regulatory applications and proceedings. Although it is difficult to quantify these savings, given that a major regulatory proceeding usually costs customers between $300,000 and $1.5 million, this is potentially a significant cost saving.

If approved, the amalgamation and adoption of postage stamp rates would be effective in 2015. As discussed in the response to FEI-FBC CEC PBR IR 3.2.3, any adjustments that are required as a result of that decision will be incorporated into the forecasts starting in 2015. The savings discussed primarily related to lower short-term interest expense in FEVI and FEW, and reduced regulatory savings that are currently captured in deferral accounts.

21.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.21.1.

21.2 If so, please provide the expected integration savings that would arise from amalgamation and postage stamp rates.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.21.1.

VII. CONTROLLABLE EXPENSES CAPITAL (I-X)

22. Reference: FEI Exhibit B-8, CEC 1.44.1

> As stated in the response to CEC IR 1.28.1, at the very least, the prudent deferral of capital spending from one year to the next creates a present value benefit for customers.

22.1 Please explain the process by which the Commission and interveners can determine if deferral of capital expenditures has been undertaken rather than just a reduction in requirement for capital has occurred.

<u>Response:</u>

The combined incentive framework between O&M and capital expenditures and the requirement to maintain service quality, along with the Utilities' long term interest in being cost-effective providers of utility service in BC, can be expected to motivate FEI and FBC to seek an efficient but sustainable level of O&M and base capital expenditures going forward. The expectation of rebasing at the end of the PBR term and also that any increases in O&M and capital spending (beyond reasonable inflation and growth) in the years after the PBR will need to be justified in the ensuing regulatory proceeding will provide another source of discipline for the Utilities to find the appropriate levels of O&M and capital going forward.

Thus customers should be assured that overall the PBR has fostered an appropriate outcome. Determining the source of capital expenditures reductions (deferrals versus permanent reductions) is not as critical in this context.

Please also refer to the response to FEI-FBC PBR BCUC IR 3.26.1.

22.2 Please confirm that the PBR formula for determining the amount of capital spending required could produce a number which is greater than the actual capital expenditures required, such that savings might not be a result of either deferral of capital spending or reduction of capital spending requirements.

<u>Response:</u>

Not confirmed. The purpose of the PBR capital formulas is to establish an appropriate base for the level of capital requirements based on the established cost drivers. The capital formulas and their components are being tested in this regulatory proceeding. After the Commission decision the final formulas, including cost drivers and inflators will be an approved basis of determining the base capital requirements within the PBR term.

22.3 Please explain the process by which the Commission and interveners will be able to determine if a deferral of capital spending is prudent.

Response:

There is a presumption of prudence. In the event that an intervener wished to challenge that presumption, then it would do so at an Annual Review.

VIII. FLOW-THROUGH EXPENSES AND REVENUES

23. Reference: FEI Exhibit B-1, Pages 53 and 54

> The proposed PBR formulas and flow-through cost components will affect the delivery rates, exclusive of rate riders and applicable taxes. In general, rate riders pertain to an established
>
> mechanism, approved in a previous Commission process and order, for recovering or refunding specific cost or revenue variances. Rate riders will continue in the approved fashion throughout the PBR term.

23.1 Please confirm or otherwise explain that FEI and FBC propose to maintain the existing mechanisms for collection of all the rate riders currently in place.

Response:

FEI plans to maintain the existing mechanisms for collection of the Midstream Cost Reconciliation Account (MCRA), which uses Rate Rider 6, and the Revenue Stabilization Adjustment Mechanism (RSAM), which uses Rate Rider 5, that are currently in place. However, as discussed in FEI's Application (Exhibit B-1), Section D4.2.1 and D4.2.2, FEI is proposing to modify the recovery period of the MCRA and the RSAM, to be recovered over 2 years instead of the existing 3 year approved recovery period.

The existing mechanism for returning the surplus revenue collected from customers January 1, 2013 to June 30, 2013, as a result of the Generic Cost of Capital proceeding, is Rate Rider 4. This rider is effective from July 1, 2013 to December 31, 2013 so it will not be maintained into the 2014-2018 PBR period.

Additionally, other riders may be required over the five year PBR period depending on Commission decisions during that timeframe. An example is the Amalgamation Phase-in rider which FEU has requested in its Rate Design and Amalgamation Application and subsequent Reconsideration Application currently before the Commission. Another would be the Earnings Sharing Mechanism rate rider as proposed.

FBC does not employ rate riders at this time. All flow-through components are recovered by way of amortization into revenue requirements.

23.2 Please identify any mechanisms that would be expected to coincide with the annual review process.

Response:

For FEI, as an integral component of the PBR, the Earnings Sharing Mechanism rider will be established in the Annual Review process.

Also for FEI, adjustments to the RSAM rate rider (affecting the residential and commercial customer classes) will also be addressed as part of the Annual Review process.

Regarding the setting of commodity and midstream rates for FEI, the fourth quarter commodity cost and mid-stream cost flow-through applications will be occurring in a similar time period as the Annual Review; however they will be conducted separately. For information purposes FEI has generally provided a commodity and midstream cost outlook in the Annual Review process and will continue to do so in the 2014-2018 PBR.

23.2.1 Please identify any advantages FEI or FBC could see in revising the existing mechanisms under PBR to allow for review at the Annual Review process.

Response:

The intent of the Annual Review has been to deal with rate-setting and results under the PBR Plan, which, for FEI, only pertains to delivery rates. The practice of conducting commodity cost and mid-stream cost flow-through applications separately has been in place for many years and is functioning effectively. As stated in the response to FEI-FBC CEC PBR IR 3.23.2 FEI has provided information in the Annual Review process on these other rate change processes but this has typically been for information purposes only. FEI believes past practice in terms of the separate review processes for delivery rates under PBR from commodity and midstream costs continue to be appropriate.

FEI and FBC do not see any advantages to revising the existing mechanism to allow them to be included in a review process at the Annual Review.

23.3 Please identify all the currently known cost items that will be flowed through, including PBR flow through cost items and those items for which FEI and FBC currently have rate riders in place.

Response:

For FEI, all of the flow-through items are identified in Section B6.3.2 of the FEI 2014-2018 PBR Application (Exhibit B-1). These items include interest expense, BCUC approved ROE rate and capital structure changes, taxes, Pension and OPEB expenses and Insurance costs, Revenues, Depreciation rate changes and Amortization, and Rate Base other than Gas Plant in Service. Included in Rate Base are several deferral accounts which utilize rate riders to recover or refund the balance of the accounts.

FBC's flow-through items are identified in Section B6.3.2 of the FBC 2014-2018 PBR Application (Exhibit B-1) and are mainly the same as FEI's. The flow-through items include interest expense, BCUC approved ROE rate and capital structure changes, taxes, Pension and OPEB expenses and Insurance costs, Power Purchase Expense, Sales Revenue, Depreciation rate changes and Amortization, and Rate Base other than Plant in Service. FBC does not employ rate riders at this time. All flow-through components are recovered by way of amortization into revenue requirements.

IX. EXOGENOUS FACTORS

24. Reference: FEI Exhibit B-1, Page 2

Flow Through Expenses and Revenues	Revenues and non-controllable costs are forecast each year and flowed through in rates each year in the Annual Review Process.

24.1 Please explain the process by which revenues and non-controllable costs that are forecast and flowed through in rates each year are 'trued up' to actual revenues and costs.

Response:

Please refer to section B6.3.2 of the Application (Exhibit B1, page 68) for the revenues and non-controllable cost items. The flow through of expenses and subsequent adjustments to actual are carried out through making forecasts and recording variances in established deferral accounts and mechanisms that have been approved by the Commission. While the Annual Review will typically be dealing with projections or estimates of the adjustments to be made, the final adjustment resulting from the actual results occurs after the fiscal period is complete and is included in the following year's annual review.

24.2 Please identify those revenues and non-controllable costs that will not be 'trued up to actual costs but will be managed with forecasts and please explain why they are not 'trued up'.

Response:

Please refer to the responses to FEI BCUC IRs 1.21.4 and 1.21.5 (FEI Exhibit B-11, p.43-44).

25. Reference: FEI Exhibit B-1, Page 68

> *"Since Z-Factors are beyond the control of management, it is typical to include a specific list of events that trigger the Z-Factor particularly where the cost changes represent cost changes that would be passed through as part of a cost of service proceeding. The*
>
> B&V considers that the rationale for this treatment is sound. Including non-controllable costs within the formula can result in a windfall to either customers or the Company. Similarly, it is important to allow full recovery of these costs under a PBR plan, as the costs - being outside the control of management - are by definition prudently incurred costs of providing utility service that should be recovered from customers in the normal course.

25.1 Please explain how including non-controllable costs could potentially result in a windfall for the company.

<u>Response:</u>

Items such as changes in legislation or changes in revenue requirements due to Commission decisions may result in changes in both spending levels and earnings. Changes of this nature, if not flowed through as exogenous factors, would lead to windfall gains or losses for the Company (or windfall gains and losses for customers). For instance a potential one percent change in cost of capital (due to any reason determined by the Commission) can create significant changes to revenue requirement and may result in windfall for the Company.

25.2 Please confirm that the company management has at least some control over the level and manner in which it responds to non-controllable events.

<u>Response:</u>

That may or may not be the case. The Companies are obliged to ensure the safety and reliability of their utility systems, maintain the service quality at acceptable levels and comply with applicable rules and regulations. For instance in the case of a major seismic incident, the Companies have a public service obligation to restore service to pre-incident conditions in the fastest time possible and must not unduly delay or refuse to restore the service for a specific group of customers. The Companies also aim to resolve the problems of an exogenous event in the most efficient and expeditious manner but that does not change the fact that the exogenous event has imposed requirements on the Companies that are non-controllable.

25.3 Would FEI and FBC agree that exogenous factors may be considered cost-based adjustments that are more consistent with cost of service ratemaking than they are with Performance Based ratemaking?

Response:

Yes. Non-controllable costs caused by exogenous factors should be treated outside the PBR formula and likely with similar pass-through mechanisms as those used in cost of service rate making.

25.4 Please explain why or why not.

Response:

Please refer to the response to CEC PBR IR 3.25.3.

25.5 What limits do FEI and FBC propose with respect to allowance of cost based adjustments?

Response:

The Companies do not propose either a materiality threshold for recovery of costs caused by exogenous factors or an overall limit on the total cost that can be treated that way. FEI and FBC believe that placing a materiality limit is most likely to deny prudent cost recovery and unnecessarily increase the underlying risk to the Companies. Please refer to response to FEI-FBC CEC PBR IR 3.32.1.

25.6 Please explain the criteria that are used in other jurisdiction to limited allowance for cost based adjustments PBR and to the extent that FEI and FBC are not proposing such limits please explain why?

Response:

For a review of the criteria in other jurisdictions please refer to response to FEI-FBC CEC PBR IR 3.27.2. The reasons for not proposing such thresholds or limits are explained in response to FEI-FBC CEC PBR IR 3.32.1.

26. Reference: FEI Exhibit B-1, Page 68

> B&V refers to all non-controllable factors as "Z-Factors", but the nomenclature differs from jurisdiction to jurisdiction. The AUC, for instance, adopts the term "Y-factors" for foreseeable uncontrollable expenditures, and uses the term "Z-Factors" only to describe those uncontrollable factors that are also unforeseen. FEI has similarly differentiated between factors that are foreseen and those that are not foreseen, although it does not generally use the term "Y-factors" when describing foreseen uncontrollable costs and revenues. There is no requirement to follow

26.1 Please confirm or otherwise explain that the flow through expenses that are uncontrollable but not unforeseen, and equate to Y-factors in the recent AUC decision would include:

- Interest expense
- Return on Equity
- Taxes
- Pension and OPEB Expenses and Insurance Costs
- Revenues
- Depreciation and Amortization
- Rate Base other than Gas Plant in Service (from Capital Expenditures)

<u>Response:</u>

Confirmed.

26.2 Please discuss whether or not FEI and FBC have an incentive to minimize any of the costs, or to maximize revenues that are flowed through as Z factors and please explain how that incentive works?

<u>Response:</u>

The flow-through aspects of the items listed in FEI-FBC CEC PBR IR 3.26.1 are discussed in section B6.3.2 of the FEI and FBC Applications (FEI Exhibit B-1 and FBC Exhibit B-1). There are no incentives to minimize costs or maximize revenues for items that are flowed through as Z-factors. Where possible the Companies work to influence outcomes, particularly in circumstances where governments conduct industry consultations before introducing a regulation, policy or tax change, but ultimately the final change imposed is beyond the Companies' control. FEI and FBC also work to manage and minimize impacts of externally-imposed changes in whatever ways are within their means.

27. Reference: FEI Exhibit B1-1, Appendix D1, Pages 44 and 46

> The Y-Factor represents deferral accounts and pass-through type adjustments related to costs that are beyond the control of the utility such as upstream transportation costs and a variety of other similar costs traditionally recovered outside of the scope of distribution related rates. This treatment is consistent with the opportunity to earn the allowed return. Neither plan contains a K-Factor for extraordinary capital investment. Without knowing the current state of the systems, and the tradeoffs that incurred as part of the settlement, it is impossible to judge the importance of this factor to EGD and Union.

> other jurisdictions. Likewise, FBC provided a list of factors that would trigger operation of the Z-Factor. This is the appropriate treatment for these costs, as discussed above in evaluating the AUC Plan. In addition to the Z-Factor, the FEI and FBC Plans included both a Y-Factor and a K-Factor. The Y-Factor included a number of flow-through adjustments that were necessary to allow the inclusion of costs not subject to the PBR, as well as the continuation of deferral and variance accounts that provided a reasonable opportunity for the LDC to earn the allowed rate of return under either PBR or cost of service regulation. The K-Factor was of particular importance for FBC because it recovered costs associated with an approved capital plan as part of the revenue requirements approved annually. These factors are discussed in more detail related to the AUC Plan.

27.1 Why do AUC and other jurisdictions distinguish between Z factors and Y factors?

Response:

Y-Factors are generally pass through items including deferral accounts. This is just a way of creating categories of adjustments that fall outside of the scope of the PBR Formula.

27.2 Please explain any difference in treatment that is afforded Y factors and Z factors in AUC or other jurisdictions.

Response:

The table below that summarizes Y factor and Z factor treatment in AUC and other jurisdictions was prepared based on Appendix D-1: PBR Jurisdictional Benchmarking Report of the Application prepared by B&V.

	Treatment	
Jurisdiction	**Applicability**	**Materiality**
ALBERTA		
Y-Factor *(Foreseeable and reoccurring events that are beyond the control of the company)*	1. The costs/impact of event must be attributable to events outside management's control. 2. The costs/impact of event must have a significant influence on the operation of the company 3. The costs/impact of event should not have a significant influence on the inflation factor in the PBR formulas. 4. The costs/impact of event must be prudently incurred. 5. All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts (Y-Factor)	40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established
Z-Factor *(Unforeseeable events outside the control of the company, for which the company has no other reasonable opportunity to recover the cost within the PBR formula)*	1. The costs/impact of event must be attributable to events outside management's control. 2. The costs/impact of event must have a significant influence on the operation of the company 3. The costs/impact of event should not have a significant influence on the inflation factor in the PBR formulas. 4. The costs/impact of event must be prudently incurred. 5. The impact of the event was unforeseen (Z-Factor)	40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established
ONTARIO		
4th GENERATION IR		
Y-Factor (Deferral and variance accounts)	Routine, or expected, cost changes that are outside the scope of the annual adjustment mechanism	Not applicable

	Treatment	
Jurisdiction	**Applicability**	**Materiality**
Z-Factor *(treatment for unforeseen events)*	1. Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived. 2. The amount must have been prudently incurred. 3. The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor	1. Utility with Revenue Requirement less than or equal to $10 Million: $50 thousand Threshold 2. Utility with Revenue Requirement greater than $10 Million but less than or equal to $200 million: 0.5% of distribution revenue requirement Threshold 3. Utility with Revenue Requirement of more than $200 million: $1 million Threshold
EGD and Union (2008-2012 plans)		
Y-Factor (Deferral and variance accounts)	Routine, or expected, cost changes that are outside the scope of the annual adjustment mechanism	Not applicable
Z-Factor *(non-routine events that were not otherwise recovered in the annual adjustment mechanism)*	1. The event must be causally related to an increase or decrease in the distributor's cost 2. The cost increase/decrease must be beyond the control of the Company management and not a risk a prudent utility could mitigate 3. The cost increase/decrease must not be otherwise reflected in the annual rate adjustment mechanism 4. The cost increase/decrease must be prudently incurred	The amount of the cost increase/decrease, for the sum of all individual events reflected in an annual Z factor filing, must be greater than the materiality threshold of $1.5 million.

27.3 In the earlier PBR period, what was the justification for having separate Y and K factors separated out from the Z factors?

Response:

Y, Z and K factors can all be considered to be variations on a similar theme – they all represent cost items that are non-controllable in some sense and are outside the PBR formulas. PBR plans permit these items because without the adders or variance accounts the formula approach to rates or revenue requirements would not allow the utility a reasonable opportunity to earn its allowed return. Y factors were for flow-through items that would be included in the revenue requirements but subject to a deferral account to capture variances from forecast. The

K factor was for CPCN capital expenditures that were outside the PBR formulas. The Z-factor was meant to cover new non-controllable items that were imposed by external events. In practice the boundary line between Y, Z and K factors can sometimes be blurred. Each of these items continues to be present in FEI's and FBC's 2014 PBR proposal.

27.3.1 Please outline any differential in treatment for Y factors, K factors and Z factors that was afforded under the earlier PBR processes for FEI and FBC.

<u>Response:</u>

The same categories of Y factors, K factors and Z factors are also present in FEI's and FBC's 2014 PBR proposals. The differential treatment depends primarily on the type of costs (O&M vs. capital) and the approved cost recovery treatment. The approved cost recovery treatments for each of these categories were based on commonly used cost of service methods accepted by the Commission. Please refer to the response to FEI-FBC CEC PBR IR 3.27.3.2.

27.3.2 Please outline the list of factors that would trigger operation of the Y, K and Z factors for both FEI and FBC in their earlier PBR proposals.

<u>Response:</u>

The same circumstances that will trigger one of these factors in the proposed 2014 PBR plans were applicable in the earlier PBR plans:

- Y-factor - a cost reflected in the revenue requirement (by a forecast), subject to a variance account and with treatment of the variance account balances approved by the Commission.
- K-factor – the Utility files a CPCN application, which after approval is constructed and added to rate base.
- Z-factor – an exogenous event causes a new externally imposed cost. An application to recover the Z-factor costs is approved by the Commission after reviewing the matter in the Annual Review process.

27.3.3 Please provide the list of criteria that the Y, K and Z factors had to meet to qualify for flow through adjustment for both FEI and FBC.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.27.3.2.

28. Reference: FEI Exhibit B1-1, Appendix D1, Page 29

> **K-Factor**
>
> Capital expenditure projects over the $5 million threshold were excluded from the capital formula, and instead CPCN applications were filed for these capital projects. Once a CPCN application was approved, the capital cost, including AFUDC, was added to rate base in the year following completion of the capital project.

28.1 Please confirm that the current proposed treatment for CPCNs is identical to that which was applied under the K-factor in the earlier period, such that the two could be considered interchangeable.

Response:

Confirmed.

28.1.1 If not confirmed, please identify the distinguishing characteristics between the K factor of the earlier PBR period and the current proposed treatment of capital expenditures over the $5 million threshold.

Response:

Please refer to response to FEI-FBC CEC PBR IR 3.28.1.

29. Reference: FEI Exhibit B-1, Page 70

> - Judicial, legislative or administrative changes, orders or directions;
> - Catastrophic events;
> - Bypass or similar events;
> - Major seismic incident;
> - Acts of war, terrorism or violence;
> - Changes in GAAP, standards or policies; and
> - Changes in revenue requirements due to Commission decisions (examples include rate design issues, depreciation rate changes, changes to cost of capital).
>
> Exogenous or Z-Factor treatment of the above costs will ensure that customers pay only for the actual costs in circumstances where FEI does not control the level of expenditures. For further discussion of the rationale for exogenous factor treatment, please refer to the B&V PBR Report (Appendix D1), p.7.

29.1 Please confirm that the above list is a complete list of the items that would be treated as 'exogenous factors' and further that any event that is not characterized by these descriptions would not count as exogenous.

Response:

Not confirmed. The list provided in the question preamble is representative of the types of events that would be non-controllable and require unforeseeable costs to be incurred by the Companies but may not be exhaustive. However the Companies believe that the common and anticipated types of exogenous event examples are included in the list.

29.1.1 If not confirmed, is it FEI and FBC's position that all events that are beyond the company's control should be treated as exogenous?

Response:

In principle yes, however, the Companies may not apply to recover amounts related to small events that do not have an impact on the Companies' ability to serve its customers and that do not have a material cost impact

29.2 Please explain what is meant by 'Bypass or similar events'.

Response:

Please refer to the response to FEI-FBC BCUC PBR IR 3 22.1.

29.3 By what measures would FEI and FBC determine something was a 'catastrophic event'?

Response:

The Companies would consider a number of measures of risk to determine a catastrophic event including operational impacts such as customer outage, transmission, distribution, generation, health, safety, environmental and IT operations/security. Further, financial loss, reputational impact and legal/regulatory compliance are also major factors.

29.4 Do FEI and FBC propose a threshold for a 'major seismic event'?

Response:

A major seismic event is intended to be any seismic event that causes damage to the system. It is intended to differentiate an event that causes damage from a seismic event that does not cause damage. The Companies do not propose any threshold apart from a requirement that there be damage caused to the system.

Please also refer to the response to FEI-FBC CEC PBR IR 3.29.3 for the Companies' considerations of a catastrophic event.

29.4.1 If so, what is it? Please provide a rationale.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.29.4.

29.4.2 If not, why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.29.4.

29.5 Please confirm that FEI and FBC will request an adjustment for exogenous factors that result in savings as well as costs. For instance, changes in legislation could result in reduced spending in regulatory or other departments; changes in GAAP could result in savings, a catastrophic event could result in reduced long term vegetation management requirements or a seismic event could provoke earlier replacement of aging equipment resulting in lower O&M expenses. Please explain.

Response:

Adjustments for exogenous factors may be positive or negative. If there are savings resulting from these factors the revenue requirements will be reduced. Circumstances of exogenous factors giving rise to revenue requirement reductions, such as reductions in income tax rates, have occurred in previous PBRs and were incorporated in rates accordingly.

29.5.1 If not confirmed, how do FEI and FBC propose to account for potential savings that are either directly or indirectly related to an exogenous event?

Response:

Not applicable. Please refer to the response to FEI-FBC CEC PBR IR 3.29.5.

29.5.2 In the event that an exogenous factor results in savings, would FEI and FBC have a duty to report savings to the Commission? Please explain why or why not.

Response:

FBC and FEI would advise of the adjustments as part of the Annual Review process just like exogenous factors that result in costs. In the 2004 PBR, for instance, FEI flowed through favourable tax rate changes. If an exogenous factor gives rise to an effect that occurs part way through a year already under way and that has not already been included in the rate setting process, the partial year amount will be captured in a deferral account and brought forward for returning to customers in the subsequent year's rates.

29.5.3 How would FEI and FBC propose to bring the savings to Commission attention?

Response:

Any changes due to exogenous factors, whether they represent cost increases or decreases will be brought forward in the Annual Review process. The materials presented will include an explanation of the cause of the exogenous factor (including, as required, copies of any source materials, such as legislation, regulations or other official documentation) and a calculation of the revenue requirement impact.

29.6 Would the Z factor costs and savings be limited to direct costs or could they include indirect costs such as overhead? Please explain how Z factor costs will be accounted for.

Response:

All incremental costs, including incremental indirect costs, that are identified with an event should flow through. The accounting for the costs will depend on their nature and timing and can only be addressed in the circumstances at the time.

29.7 Please confirm that all Z factor costs would be subject to Commission review and approval for prudency of expenditure.

Response:

FEI confirms that the costs for all Z-factor or exogenous factor application must be prudently incurred in the same way that all other utility costs must be expended prudently.

FEI would provide evidence of its costs for a Z-factor event in the next Annual Review process for consideration. In some cases, such as catastrophic events, the activities and costs involved in dealing with the event may extend over more than one fiscal year and if so it will be necessary to accommodate this timing in the rate recovery process. The Commission and stakeholders have dealt many times with the recovery of costs from Z-factor type events in utility rates and various mechanisms such as flow throughs, deferral accounts, true-ups and others have been employed to accomplish this. FEI expects that recovery of Z-factor costs during the PBR would follow procedures that have been employed many times by the Commission before and that it is not necessary to be overly prescriptive in advance to set out a specific procedure, particularly since different processes may apply for different Z-factor costs.

If the suggestion is that any Z-factor or exogenous factors application must automatically be subject to an after the fact prudency review in the formal sense, then FEI would disagree.

29.7.1.1 If so, please explain the process by which the Commission would approve or not approve the Z factor cost or savings.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.29.7.

29.7.1.2 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.29.7.

29.8 Would FEI and FBC provide notification to the Commission of an event that it expects will give rise to exogenous costs when it occurs, within the Annual Review process or at another time? Please explain.

Response:

The Companies will keep the Commission apprised of exogenous events. The type of notification will depend on the extent, timing and circumstances of the exogenous factors. Some items such as changes in GAAP or items that result from Commission Decisions will be provided within the Annual Review Process. For other items, forms of notification may include letters to the Commission, and the Companies will include discussion of exogenous factors during each Annual Review process.

29.8.1 Do FEI and FBC expect to require prior approval for Z factor expenditures, or to incur the expense and seek approval after the fact?

Response:

FEI and FBC intend to operate as always in a prudent manner to provide safe reliable service to its customers at a reasonable cost. If Z factor expenditures are required, the Companies will act according to the circumstances and plan the appropriate actions, including informing the Commission as appropriate. The Companies may incur required expenditures in advance of notifying the Commission depending on the urgency imposed on its operations by the Z factor event.

Please also refer to the response to FEI-FBC CEC PBR IR 3.29.8.

29.9 Do FEI and FBC propose that the Commission review the Z factor on a case by case basis, or cumulatively? Please explain.

Response:

The Companies believe that the treatment of exogenous or Z-Factor expenditures can be dealt with on a case by case basis as appropriate to the circumstances. As discussed in the response to FEI-FBC CEC PBR IR 3.29.8 FEI and FBC will include an updated discussion of exogenous factors in each Annual Review.

29.9.1 Would FEI and FBC agree that they have a duty to mitigate any and all costs that are incurred addressing exogenous factors?

Response:

The Companies agree that they have a duty to prudently manage the costs incurred with respect to exogenous factors. In considering the prudency of incurred costs, the actions taken to mitigate such costs may be considered.

29.9.1.1 If so, how can it be determined that FEI and FBC have conducted proper mitigation activities.

Response:

In considering exogenous factor claims, the Commission may review all mitigation activities and expenditures by the Company pertaining to exogenous factors.

29.9.1.2 If not, please explain why not.

Response:

Please refer to the responses to FEI-FBC CEC PBR IRs 3.29.9.1 and 3.29.9.1.1.

29.10 In the event of a catastrophe or other exogenous event could this result in O&M or other savings in the PBR period?

Response:

While it may be possible that O&M savings could be created, the types of events described generally increase costs and are unlikely to create savings. Further, there may be other impacts such as the loss of revenue that may impact earnings. Stakeholders would be able to explore the possibility of any O&M savings being generated in association with the catastrophic event in the Annual Review process where the Z-factor application is brought forward.

29.10.1 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.29.10.

30. Reference: FEI Exhibit B-8, CEC 1.25.2

> within the budgeted costs for the regulatory process (i.e. no extraordinary litigation costs or compliance costs associated with the regulatory reporting and monitoring of the Plan). It also assumes timely resolution for exogenous cost changes such that FEI is not required to absorb major cost changes for long periods during the pendency of the Plan. In general, the statement

30.1 Within what period of time would FEI and FBC consider to be 'timely resolution' for exogenous cost changes?

Response:

The appropriate period of time for resolution of exogenous factor cost changes would be dependent on the nature of the specific exogenous event or costs. If it is an item that causes ongoing cost increases or decreases such as a new tax or tax rate change it would be solved by reflecting the new item in the revenue requirements from the point of introduction forwards. Recovery from a one-time event such as a catastrophic event and finalizing the costs may take some time. The important point in quotation from FEI CEC IR 1.25.2 (Exhibit B-8) is that the exogenous factor provisions of the PBR Plan provide a means for bringing such matters forward during the PBR term to obtain approval of cost recovery. The actual recovery of the costs may extend beyond the PBR term but the resolution of how the costs will be treated has occurred in a timely fashion.

30.2 Would FEI agree that it could be extremely difficult to accurately determine the net costs associated with major events such as catastrophes and major seismic events?

Response:

No. In such an event, the utilities keep records of the costs incurred to restore service. In some cases the utilities may have reasonable estimates of the lost revenues.

30.2.1 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.30.2.

30.2.2 If so, would FEI and FBC agree that in such incidents it may be preferable to trigger an off-ramp than a flow through costing?

Response:

FEI and FBC believe the proposed off-ramps are adequate and that most of the exogenous events can be appropriately accommodated with the proposed flow-through treatment. Flowing through costs results in more timely recovery and protects the financial integrity of the Companies. If an extraordinarily large event occurred that had material impacts on the Utilities' ability to continue operating it may be appropriate to consider an off-ramp. The Utilities believe consideration of that possibility can be addressed if and when such a large scale event occurs.

31. Reference: FEI Exhibit B1-1, Appendix D, Page 7

> within the PBR formula, are eligible for Z-Factor treatment[18]. The following five criteria, of which all must be satisfied, have been adopted by the AUC in determining eligibility for Z-Factor treatment:[19]
>
> 1. The impact must be attributable to some event outside management's control;
> 2. The impact of the event must be material. It must have significant influence on the operation of the utility otherwise the impact should be expensed or recognized as income, in the normal course of business;
> 3. The impact of the event should not have a significant influence on the inflation factor in the PBR formulas;
> 4. All costs claimed as an exogenous adjustment must be prudently incurred; and
> 5. The impact of the event was unforeseen.

31.1 Please confirm or otherwise explain if FEI and FBC have proposed specific qualification criteria for exogenous items and please identify where that criteria is provided in the application and compare the FEI and FBC criteria to the AUC criteria.

Response:

Items 1 and 5 of the AUC list are indicated in Companies' Applications. For instance please refer to FEI' Application (Exhibit B-1) Section 6.3.3 where it is stated that "in the nomenclature of PBR, **non-controllable and unforeseeable costs** that flow-through to rates are referred to as Z-Factors. These factors were referred to in the 2004 PBR Plan as exogenous factors. Consistent with the 2004 PBR Plan, FEI proposes that during the term of the proposed PBR Plan, customers' rates will be adjusted for the following **exogenous factors that are beyond the control of the Company**".

Item 4 is not directly mentioned in the Application however prudency in expenditures is applicable to all the Utilities' costs and is not limited to exogenous factors. Since this is a given a separate criterion seems to be unnecessary.

Item 2 of this list is not applicable to FEI's and FBC's Application. Please refer to response to FEI-FBC CEC PBR IR 3.32.1 for reasons why placing a materiality limit is most likely to deny prudent cost recovery and increase the underlying risk.

Item 3 is also not supported by the Companies as it is written in AUC Decision. The three exogenous factors that are more likely to have substantial impact on economy-wide input prices are catastrophic events, major seismic incidents and Acts of war, terrorism or violence. It is improbable that even a substantial rise in the inflation rate for the I-Factor in the PBR formula could recover the costs of these events. For instance in the aftermath of natural catastrophe there is an increased demand for skilled reconstruction labor which may lead to significant increases in the AWE part of the proposed composite inflator (This increase in inflation is often referred to as the Demand Surge effect). As the name indicates this significant increase in inflation is needed to address the issue of a sharp rise in the demand for skilled labor or other cost inputs and in no way covers the actual costs of reconstruction itself. In addition, it is common practice in the face of major events to call on utility crews from other utilities to assist with service restoration. In that event, the utility incurs added costs for housing and feeding these crews as well as paying for their time including overtime rates since most crews work at least twelve hours per day.

31.1.1 If FEI and FBC do not propose specific qualification criteria, please explain why not.

Response:

Please refer to response to FEI-FBC CEC PBR IR 3.31.1.

31.2 Do FEI and FBC concur that meeting all five of the above criteria are appropriate for treating an expense as exogenous?

Response:

Please refer to response to FEI-FBC CEC PBR IR 3.31.1.

31.2.1 If not, please identify any additions or deletions to the above list, and explain individually why each should or should not be included.

Response:

Please refer to response to FEI-FBC CEC PBR IR 3.31.1.

31.3 Please confirm that exogenous events can be foreseen as a possibility but the timing and extent of the realization of exogenous events can be difficult to estimate unless they are frequent and regular enabling the use of statistical methods to characterize timing and impact.

Response:

The Companies confirm that certain exogenous events can be foreseen. Even events that may be estimated with statistical methods can still be quite variable within a particular period of time and should be considered uncontrollable. If a particular exogenous item was able to be forecast by statistical methods but still subject to fluctuations it may be possible to include a forecast amount in rates and use a deferral account to capture year-to-year variances.

32. Reference: Exhibit B-1-1, Appendix D, Page 7 and Page 15 and FEI Exhibit B-6, BCPSO

With respect to the materiality of the Z-Factor, the AUC determined that the exogenous event, in addition to meeting the above five criteria, must result in "the dollar value of a 40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established"[20] to qualify for Z-Factor treatment.

Table 5: Z-Factor Materiality Threshold Relative to the Size of Distributor's Required Revenue

Size of Revenue Requirement	Materiality Threshold
Less than or equal to $10 million	$50 thousand
Greater than $10 million and less than or equal to $200 million	0.5% of distribution revenue requirement
More than $200 million.	$1 million

FEI recommends no materiality provision on the exogenous factor adjustments. FEI and B&V believe that placing a materiality limit is most likely to deny prudent cost recovery and thus increase the underlying risk. The cost increases or decreases arising from exogenous factors are non-controllable costs that would be subject to recovery in rates under cost of service-based ratemaking without any materiality threshold. The appropriate mitigation of this risk is to not set a limit on recovery.

32.1 Please explain, with examples, how placing a materiality limit is most likely to deny prudent cost recovery and increase the underlying risk.

Response:

B&V provides the following response.

Equity return is calculated as a residual. For every dollar of expense that does not flow through the Z-Factor there is a one dollar less of earnings. It is unlikely that factors that would meet the Z-Factor test would be wasteful or imprudent expenses since the costs would be incurred beyond the control of management and therefore would be prudent to maintain service or comply with laws or regulations. Any threshold prior to recovery increases risk because the company is exposed to reduced earnings in the event of an exogenous factor occurring creating earnings variability that is a risk factor.

32.2 Have FEI and FBC had materiality thresholds related to K, Y or Z factors in previous PBRs?

Response:

FEI and FBC did not have materiality thresholds related to Y or Z factors in previous PBRs.

With respect to 'K-Factor', the Companies interpret this to mean 'Capital Tracker' for capital expenditures excluded from the PBR formula. Under its previous PBR plan, FEI excluded CPCN expenditures for capital projects from the PBR formula, with a materiality threshold of $5 million. FBC did not have a capital formula in its most recent PBR plan so the capital tracker consideration was not applicable. The Companies and B&V consider that the exclusion of CPCN capital is an appropriate means of addressing capital under their proposed PBR Plans.

32.2.1 If so, please provide the materiality thresholds that were implemented before.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.32.2.

32.3 Is FEI and FBC's position that all costs directly and indirectly related to exogenous factors would be subject to a Z factor adjustment?

Response:

All identifiable incremental costs, whether direct or indirect, associated with the events beyond the control of management, should be recoverable in rates.

32.3.1 If this is not FEI and FBC's position, please clarify.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.32.3.

32.4 Please confirm or otherwise explain if FEI and FBC would consider an exogenous factor adjustment, regardless of how small, to be entirely at management discretion.

Response:

FEI and FBC will bring forward exogenous factor issues, positive or negative in the Annual Review process each year. There is no incentive for management to forego cost recovery as long as it does not cost more to add the costs to the Z-Factor than the cost itself.

32.5 Please confirm that the 'no materiality limit' would apply to potential savings as well – such that an adjustment would be required for any and all savings that arise from an exogenous event such as a change in GAAP.

Response:

Confirmed. The Z- Factor as proposed would be the net cost or savings from the exogenous event.

32.5.1 If not confirmed, please explain if it is FEI's and FBC's position that there should be a materiality limit on potential savings, or if such savings should be adjusted at management's discretion as well.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.32.5.

32.6 Is it FEI and FBC's position that managing the costs and possible savings associated with minor exogenous factors is not a management responsibility? Please explain why or why not.

Response:

Exogenous factors should, in principle, flow through. However, when the changes are *de minimis* management may not seek recovery.

32.7 Would FEI and B&V agree that frequent Z factor applications would result in increased regulatory costs and would thereby be contrary to the spirit of PBR? Please explain why or why not.

Response:

Yes, frequent applications may result in increased regulatory costs, but the Companies disagree that this is contrary to the spirit of PBR, as the Z factor applications are for events that are beyond the control of management. Based on past experience Z-factor applications have not been frequent, even though the same or similar provisions were included in prior PBRs. The Companies do not have a reason to expect this to change. Note that FBC and FEI have stated in the response to FEI-FBC CEC PBR IR 3.32.6 that when the changes are *de minimis* management may not seek recovery. These Z factor applications will be considered as part of an already existing Annual Review process and should not drive significant incremental regulatory costs. Further, these exogenous factors are the same factors that are also given separate consideration in cost of service applications.

X. BENCHMARKING STUDIES

33. Reference: FEI Exhibit B-8, CEC 1.31.3 and CEC 1.3.15

> **Response:**
>
> Generally speaking, FEI and B&V have reviewed the economic literature and have also studied the reports prepared by other consultancy firms for the purpose of the preparation of this PBR plan. Therefore it is fair to say that we are relatively familiar with the studies that are conducted in other major Canadian jurisdictions (particularly Ontario and Alberta).
>
> Taken together these issues impact cost benchmarks in ways that provide little useful information for assessing relative performance. Again a simple example will illustrate this point. For larger customers, meters are customized for each installation and the costs may run into hundreds of thousands of dollars. If one was studying the cost of industrial meters two utilities could have the same number of customers and very different meter costs because of the size of the customers that impacts the cost. It is also true that other factors such as labor rates can significantly impact costs across companies and regions.
>
> There are so many considerations that it is difficult to develop sufficient controls for a benchmark study with a large enough sample to be valid.

34. Please confirm that such benchmarking pools of participating utilities for both gas and electric utilities do exist and that they do have procedures for defining and controlling for differences between jurisdictions such that they provide serious and significant comparability but clearly not perfect comparability.

Response:

There are certainly utilities that participate in benchmarking studies among themselves. Further, there are efforts to control for differences between jurisdictions. The term serious and significant comparability are subjective terms, and cannot be judged except within the confines of the utility group itself. For example, there is no practical way to control for the myriad of local regulations that impact gas distribution services within the utility that result in higher costs to comply with those regulations which may differ by locale even in the utility. In addition, differences in internal organizations can cause cost differences between benchmarks for specific activities. In general, benchmark studies may provide a ranking based on a benchmark factor but may tell nothing about efficiency based on the ranking.

XI. CPCNS AND AMI

35. Reference: FEI Exhibit B-8, CEC 1.43.1

> For most ongoing projects, FEI does not employ probabilistic estimating techniques due to the higher costs that would be incurred (with little offsetting benefit). Instead, project costs are typically single-value estimates with a contingency. This estimating method is straightforward to apply and relies on professional judgement and historical costs from similar completed projects. Since the vast majority of FEI capital projects are recurring in nature, this is a cost-effective method of developing project estimates. The estimates used for capital planning are either to AACE Class 5 or 4 degree of accuracy depending on the nature and timing of the project.
>
> Regardless, the delivery rates for the PBR Period will be set using the capital formula, and not the capital estimates that have been provided in this Application.

35.1 Please confirm that, once approved, the O&M costs associated with CPCNs are included in the O&M base by which FEI and FBC will earn income if costs savings contribute to lower costs than the PBR formula projects the costs to be.

<u>Response:</u>

It is confirmed that CPCN-related O&M cost increases or decreases are captured in the O&M formula and may give rise to decreases or increases in income (that, if either occurs, will be subject to 50/50 sharing). Please refer to the response to FEI BCUC IR 3a.305.2, being filed concurrently with the PBR Methodology IRs.

35.2 Please confirm that the AMI project is expected to lower O&M costs in the future and please provide the FBC estimate for how much this is expected to be.

<u>Response:</u>

Confirmed. The reduction to FBC's O&M Expense resulting from the AMI Project is tracked outside of the PBR Formula for O&M, as shown at line 23 of Table B6-5 (page 53) in the Application. The AMI Project results in a slight increase in 2014, followed by O&M Expense reductions thereafter. The net O&M Expense decrease over the 2014-2018 period is $7.645 million. The O&M impact by year is shown in the following table.

	2014	2015	2016	2018	2018	Total
	($000s)					
AMI – O&M Expense Increase/ (decrease)	368	(439)	(2,411)	(2,369)	(2,794)	(7,645)

XII. EARNINGS SHARING MECHANISM

36. Reference: FEI Exhibit B-11, 1.24.1

> FEI reviewed the merits of various ESM structures and also considered its own experience with ESM to decide on the best option. FEI decided not to use a dead-band for following reasons:

36.1 Please provide a discussion of the advantages and disadvantages of 'dead-bands' within the Earnings Sharing Mechanism.

<u>Response:</u>

Please refer to responses to FEI-FBC BCUC PBR IR 3.32.2, FEI BCUC IR 1.24.1 (Exhibit B-11) and FEI BCPSO IR 1.24.2 (Exhibit B-6).

In addition B&V provides the following complementary response.

Dead-bands have the impact of altering the marginal benefits associated with efficiency changes resulting in the potential for opportunistic behavior by the Company and other stakeholders. Consider for example a sharing mechanism with a dead band as follows: The allowed return is 10% and the dead-band is plus or minus 200 basis points or between 8% and 12%. The marginal benefit of efficiency investments is 100% to the utility between 8% and 12%. For earnings above 12% the utilities marginal benefit is 50%. Below 10% but above 8% shareholders lose 100% but only lose 50% with earnings below 8%. In considering these issues, rewards resulting from efficiency gains when earnings are above 8% accrue 100% to shareholders until earnings reach 12%. The incentive to continue to find efficiency gains beyond that point is reduced.As it becomes more difficult to create cost savings, the reduction in incentives makes larger savings less attractive. By having no dead-band, the incentives for cost efficiency remain the same regardless of actual earned return.

There is also an incentive for inter-period cost shifting in the face of a dead-band as follows. If the utility knows that returns in one year are likely to be on the low end of the range, it would be rational for the utility to accelerate expenses into the year and have the customers bear 50% of those losses. In the next year, the utility would retain 100% of the resulting savings for shareholders so long as they did not exceed the upper bound of the dead-band.

There are also incentives for regulatory opportunism by other stakeholders to seek denial of cost recovery on specific items to force the utility return above the dead-band to gain a share of earnings at the margin. By allowing this type of regulatory opportunism, the utility has less incentive to expand efficiencies when its earnings are above the allowed return.

The symmetric sharing above or below the allowed return eliminates these types of incentives and adds credibility to the PBR Plan for all stakeholders.

XIII. EFFICIENCY -CARRY OVER MECHANISM

37. Reference: FEI Exhibit B-1, Page 75

> B&V supports the proposed ECM because it permits the utility to maintain a continuous improvement culture rather than be concerned about the inability to earn the required return on investments made in efficiency and productivity occurring in the later years of the PBR Plan. By permitting a carryover to match the initial period of the plan, the utility invests in measures throughout the plan period and there is no disincentive as the PBR Plan comes to an end.

37.1 Please confirm or otherwise explain that at the end of the PBR period, FEI and FBC would be incented to continue improvements at the end of the PBR period, but would have limited incentives to maintain SQIs.

<u>Response:</u>

FBC and FEI will continue to seek productivity improvement opportunities at the end of the PBR period. Please refer to the response to FEI-FBC CEC PBR IR 3.20.1.

FBC and FEI will also continue to work diligently to keep customer service at the target levels set out throughout the term of the PBR Plan. The Utilities are acting in good faith in these matters and will make every effort to address customer concerns about service quality if and when they are raised.

At the end of the PBR term the Utilities will be coming into a regulatory review for their next revenue requirements period, which will most certainly review service quality trends along with other aspects of the revenue requirements application. The prospect of this review should be another factor that eases any stakeholder concerns about the Utilities allowing service quality to deteriorate.

38. Reference: Exhibit B-8, CEC 1.47.1

> During the term of the PBR plan, the actual revenue requirement impact (depreciation, taxes and financing costs) of the capital expenditure savings relative to the formula-allowed expenditure levels is the source of the capital-related benefit, while after the five-year term under the ECM, a fixed percentage (rate base benefit factor) which is representative of the avoided revenue requirements from the reduced capital expenditures is the source of the benefit.

38.1 Given that there is an ECM for the end of the PBR period, please comment on the appropriateness of an efficiency carry over mechanism for the beginning of the PBR period.

Response:

The efficiencies achieved under cost of service plan are already embedded in the revenue requirement used to establish the going-in rates. Therefore, ratepayers will receive the benefit of these efficiency improvements during the PBR term. The potential efficiency gains that may occur beyond 2013 base year cannot be included in the 2013 cost of service revenue requirement. Nevertheless, under the PBR's proposed X-Factor, the customers will benefit from expected productivity gains during the PBR term, regardless of whether the efficiencies have materialized or not.

39. Reference: FEI Exhibit B-1-1 Appendix D6, Page 5

Table D6-1: Rate Base Carrying Cost by Asset Type

Asset Type	Depreciation & CCA Rates	Five-Year Levelized Rate Base Carrying Cost
Low Depreciation – Low CCA (Distribution Mains)	Depreciation rate – 1.48% CCA rate - 6%	9.6%
Medium Depreciation – Low CCA (Meters)	Depreciation rate – 7.89% CCA rate - 6%	17.3%
High Depreciation – High CCA (Computer Hardware)	Depreciation rate – 20% CCA rate - 55%	24.9%

FEI believes the proposed 15 percent value for the Rate Base Benefit Factor represents a reasonable weighting of the foregoing examples, which were picked to provide a reasonable range of results.

39.1 Please provide the inputs that were used to calculate the 14% Rate Base Benefit factor in the previous PBR period.

Response:

The 14% Rate Base Benefit Factor was an element of the overall negotiated settlement package for FEI's 2004 PBR. Quotes from the 2004 PBR NSA (BCUC Order G-51-03, Appendix A, page 9 of 47) with respect the issue are provided below:

Application background column

"An example is provided in BCUC IR 1.9.2 showing a levelized saving of 13.21%. The 15% factor provides for the possibility of plant accounts with higher depreciation rates or higher cost of capital in the future."

Negotiated Settlement column

"Accepted for application only to base capital additions for the end-of-term capital benefits phase-out except that the factor should be 14%."

39.2 Please confirm that this Rate Base Benefit Factor could be quite different from the actual benefit depending upon the capital that may be affected.

Response:

Confirmed. The actual benefit may be higher or lower based on the mix of capital expenditure savings. It will be the actual benefit that accrues during the PBR term. The Rate Base Benefit Factor is only applicable after the PBR term for the capital portion of the ECM and the Company believes it to be a reasonable proxy of the estimated benefits.

XIV. SERVICE QUALITY INDICATORS

40. Reference: FEI Exhibit B-8, CEC 1.51.2

> As outlined in Appendix D-7 Service Quality Indicators, Section 2.2 Choice of Benchmarks, the proposed benchmarks are not to be considered as a minimum threshold to achieve and instead are reference points against which levels of service quality can be compared.
>
> Please refer to the response to COPE IR 1.7.8 for details of the proposed review process concerning SQI performance.
>
> FEI also confirms that it is proposing that no reward or penalties be attached to the performance of the SQIs as part of its proposed PBR plan. This is consistent with the approach applied to

40.1 Please confirm that the FEI & FBC PBR process proposed does not create financial incentives to maintain or improve service quality?

Response:

As indicated in FBC's Application (Exhibit B-1), Section B6.7.2.2 Non-Financial Triggers and FEI's Application (Exhibit B-1), Section B6.7.2.2. Non-Financial Triggers, the SQIs provide a framework for determining whether there is a need for a complete regulatory review of the PBR Plan during the mid-term assessment review. A sustained serious degradation of the SQIs provides a trigger of the off-ramp provision. The objective of SQIs is not to reward FEI and FBC for improving service quality but instead to ensure that the companies continue to provide an "acceptable level" of service at an "acceptable level" of cost.

Further, FEI and FBC believe that SQIs should not have penalties/rewards attached to their individual performance as compared to their benchmarks as it may lead to inappropriate incentives (disincentives) provided to the Companies. There may be circumstances beyond the Companies' control that contribute to variances in the performance of SQIs.

40.1.1 Please explain why or why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.40.1.

40.2 In a market competitive environment do some companies when faced with cost pressures allow elements of their service to degrade and or compromise their customer service competition to the extent that they can weaken their customer retention and acquisition?

Response:

B&V provides the following response.

The answer is that it depends on factors that impact the business model. For example, if it is more costly to acquire new customers than it is to retain existing customers it may not be economic to jeopardize customer retention because of cost pressures as that strategy would make cost pressures more severe. Regulated utilities have little incentive to compromise service quality because unlike competitive firms the utility faces regulatory review and potential adverse impacts as the result of poor customer service or system reliability. Further, the utility has the opportunity to seek to raise rates when cost pressures become unreasonable even under PBR because of off-ramps and the Mid-Term Review.

40.2.1 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.40.2.

40.3 Please confirm that ratepayers expect a service level to be maintained in exchange for enabling FEI and FBC to earn a fair return on their equity investment?

Response:

The Companies agree that under the UCA, they must maintain “reasonable, safe, adequate and fair service” (see, for instance section 25) under PBR or any other regulatory mechanism. However, this is not synonymous with maintaining specific benchmarks, divorced from context. For instance, insignificant and infrequent declines in service levels or reductions caused by factors beyond the control of the Companies shall not impact their opportunity to earn a fair return on and of their investments.

40.3.1 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.40.3.

40.3.2 Please provide what the fair return on the FEI and FBC equity investment is now and how that will be determined throughout a PBR period.

Response:

As established through BCUC Order G-75-13, FEI's equity return is 8.75 percent while FBC's equity return will be established in Phase 2 of the GCOC proceeding currently underway. These returns are expected to be in place for the 2014 and 2015 years of the PBR period. The Companies expect another GCOC proceeding in 2015 which will establish fair returns for future years within the PBR period.

In the rate setting process FEI and FBC will use their respective approved ROE and capital structure applicable in each year. The impacts of Commission decisions on the cost of capital are a flow-through item in the PBR (as they are in cost-of-service rate reviews) so there will be no windfall gains or losses in this regard.

40.4 Would FEI or FBC accept making service level benchmarks as 'minimum thresholds' that could result in penalties without making changes to other aspects of the PBR plan?

Response:

FEI and FBC do not believe making service level benchmarks as minimum thresholds with potential penalties is appropriate.

Please refer to the response to FEI-FBC CEC PBR IR 3.40.1. Failure to meet one (or more) SQI benchmarks does not necessarily constitute unacceptable performance as there may be circumstances beyond the companies' control that contribute to variances in the performance of SQIs. As result, having incentives (disincentives) related to SQI performance may lead to inappropriate outcomes. Instead of penalizing or rewarding for service quality, FEI and FBC believe a more constructive approach is to use SQIs to ensure the companies continue to provide an overall "acceptable level of service" at an "acceptable level of cost".

FEI and FBC believe that the proposed review process including the Annual Reviews and Mid-term Review provide an effective route for the Commission and interveners to express concerns about sustained and significant degradation of SQI results of the Utilities which could trigger the off-ramp provision.

40.4.1 Please explain why or why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.40.4.

40.4.1.1 Please provide any rules or regulations under which FEI or FBC would accept Service Quality indicators as being minimum thresholds.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.40.4.

41. Reference: Exhibit B-1, Page 30 and Page 42

> A concern under PBR is that efficiencies not be achieved at the expense of service quality. B&V observe that, for this reason, PBR plans typically include provisions relating to service quality. FEI's 2004 PBR Plan, for instance, included a variety of Service Quality Indicators that FEI was required to report on in the Annual Reviews. Service Quality Indicators (SQIs) are proposed in the current FEI proposal as well.

> 7. In Alberta and Ontario the SQIs are monitored during the PBR plan however there is no direct reward or penalty mechanism attached to SQIs. Gaz Metro is the only utility among those reviewed that has had SQIs with financial penalties or rewards.

41.1 Please confirm, or otherwise explain, that the Alberta Utilities Commission has determined that it has other legislative provisions on which it can rely to adopt performance standards such as AUC Rule 002 'Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors'.

Response:

As indicated in the response to FBC COPE IR 1.3.8 (Exhibit B-13)

> *"The Alberta Utilities Commission's (AUC) Decision 2012-237 rejected the use of any PBR specific reward or penalty mechanism. However the AUC's Rule 002 and 003 are used to monitor the utilities' service quality indicators performance. In addition, the AUC indicated that Alberta's Gas and Electric Utilities Acts provide the Commission with the legislative authority to take necessary actions when the Commission is of the opinion that a utility has failed to comply with its rules respecting service standards. The AUC also started a consultative process for a review of Rule 002."*

For the latest update regarding the AUC Rule 002 consultative process please also refer to FEI-FBC CEC PBR IR 3.41.4.

41.2 Please confirm, or otherwise explain that the Alberta Utilities Commission revised Rule 002 to accommodate performance standards as a direct result of the PBR process.

Response:

Confirmed. Please refer to the response to FEI-FBC CEC PBR IR 3.41.4.

41.3 Please confirm, or otherwise explain that the Alberta Utilities Commission considers that legislative remedies available to it under Section 63 of the Alberta Utilities Commission Act, Section 28.3 of the Gas Utilities Act and Section 129(3) of the Electric Utilities Act provide for penalties in the event of non-compliance with Rule 002 as a way of ensuring that companies have an adequate incentive to maintain service quality under PBR.

Response:

Confirmed. Please note that Section 63 of Alberta UCA is not specific to Rule 002 or SQIs and includes maximum administrative penalties available for non-compliance with any of the provisions of the Act. Please refer to response to FEI-FBC CEC PBR IR 3.41.1.

41.3.1 Please confirm that the Administrative Penalty under Section 63 of the Alberta Utilities Commission A provides for penalties of:

(a) An amount not exceeding $1 million for each day or part of a day on which the contravention occurs or continues, and

(b) A one-time amount to address economic benefit where the Commission is of the opinion that the person has derived an economic benefit directly or indirectly as a result of the contravention.

Response:

Confirmed.

41.3.2 Please provide a copy of AUC Rule 002.

Response:

AUC's Rule 002 can be accessed from the following link:
http://www.auc.ab.ca/acts-regulations-and-auc-rules/rules/Documents/Rule002.pdf

41.3.3 Please provide a copy of AUC Bulletin 2012-24 and AUC Bulletin 2013-6, and any other updated Bulletins related to performance metrics.

Response:

The links to the AUC Bulletin 2012-24 and AUC Bulletin 2013-6 are as follows:

AUC Bulletin 2012-24:

http://www.auc.ab.ca/news-room/bulletins/Bulletins/2012/Bulletin%202012-24.pdf

AUC Bulletin 2013-6:

http://www.auc.ab.ca/news-room/bulletins/Bulletins/2013/Bulletin%202013-06.pdf

The most recent Bulletin related to performance metrics is AUC Bulletin 2013-23 (Issued on 21-11-13) which includes a proposal for revisions to AUC Rule 002 and invites interested parties to provide written comments. The AUC Bulletin 2013-23 can be access from the link below: http://www.auc.ab.ca/news-room/bulletins/Bulletins/2013/Bulletin%202013-23.pdf

41.3.4 Would FEI and FBC not consider penalties that are assessed under AUC Rule 002 to be a direct reward or penalty mechanism attached to SQIs?

Response:

The premise of this question is wrong since there is no reference to penalties in the current or proposed revision of AUC Rule 002.

Section 63 of the Alberta Utilities Commission Act is not directly related to PBR plans and includes general maximum penalties for non-compliance with any of the provisions of the Act under any regulatory model. According to AUC Decision 2012-237 and based on Section 63 of Alberta UCA, in case of non-compliance with AUC Rule 002 a review process is launched that gives the company the opportunity to explain the source or cause of the failure and argue that a penalty is not warranted or should be lessened. If the Commission determines that a financial penalty is warranted, then the size of the penalty can be tailored to match the benefit gained by the company as a result of its action.

On the other hand, direct penalty and reward mechanisms are generally applied to PBR incentives. Under this approach penalties and rewards are computed based on a pre-determined formula (generally without any review process) which is linked to PBR incentives.

41.3.4.1 Please explain why or why not.

Response:

Please refer to response to FEI-FBC CEC PBR IR 3.41.3.4.

41.4 Please confirm or otherwise explain that the AUC undertook to examine the issue of potentially declining service quality indicators and penalizing failures under Rule 002 as a direct result of the PBR process and determinations.

Response:

As stated in response to FEI BCPSO IR 1.26.2 (Exhibit B-6)

> AUC Rule 002 sets out the service quality reporting requirements for electric and gas distributors. In AUC's Decision 2012-237, the Commission indicated that it shall initiate a consultation process to review and revise the AUC Rule 002. AUC also stated that following the completion of the consultative process, the Commission will issue a bulletin indicating the process to be followed with respect to the adjudication of penalties. AUC Rule 002 is a general rule and not specific to the PBR plans. In other words, even if the consultation process leads to development of a penalty mechanism, the defined mechanism would not be specific to a PBR plan and will apply to all the utilities even after the PBR term is finished.

The most recent Bulletin related to performance metrics is AUC Bulletin 2013-23 (Issued on 21-11-13) which includes a proposal for revisions to AUC Rule 002 (this revision does not include any proposal for penalty mechanism) and invites interested parties to provide written comments. The AUC Bulletin 2013-23 can be access from the link below:

http://www.auc.ab.ca/news-room/bulletins/Bulletins/2013/Bulletin%202013-23.pdf

41.4.1 Please provide a description of any indirect penalties that may accrue in other jurisdictions in the event that service quality degrades.

Response:

Please refer to responses to FEI COPE IRs 1.7.6 and 1.7.4 (Exhibit B-9).

41.4.2 Please provide any corresponding legislation that is available to the BCUC to assess penalties for non-compliance with performance standards.

Response:

The Companies interpret "performance standards" to be a reference to SQI's used in a PBR context. As in Alberta, there are no penalty provisions in BC specifically related to non-compliance with SQIs. There are general administrative penalty provisions in section 109.1 of the UCA for contraventions of (a) "this Act or the regulations", or (b) "an order, standard or rule of the commission or a reliability standard adopted by the commission".

42. Reference: Exhibit B-1, Page 134

> The Operations department is responsible for installing, operating and maintaining the gas distribution and transmission (pipelines) systems and plant assets in order to provide safe, reliable and cost effective service to customers. The department has three major groups, described in further detail below:
>
> 1. Distribution;
> 2. Transmission (Pipelines); and
> 3. Plant Operations (LNG and Compression).

42.1 How will the condition of assets be monitored and reported on throughout the PBR period?

Response:

Please refer to the response FEI BCUC IR 2.341.1 (Exhibit B-24) for discussion of FEI's approach and its Integrity Management Plan (IMP) for monitoring the condition of its gas system.

As indicated in the response, maintaining the condition of the system according to existing codes and standards, while not specifically linked to a proposed SQI, is the minimum expectation in terms of safety and reliability of the gas system and is a non-discretionary obligation of FEI. As such, FEI has not included reporting on the IMP as part of the PBR Plan.

XV. REOPENERS AND OFF RAMPS

43. Reference: FEI Exhibit B-1, Page 77

> Whereas the Mid-term review is intended to be a "checkpoint" to permit stakeholders to address specific and discrete flaws with an otherwise workable plan, an "off-ramp provision" is a term of a PBR Plan that contemplates a complete regulatory review of the PBR Plan in particular limited circumstances. FEI is proposing both financial and non-financial triggers for the off-ramp provision. B&V considers that the inclusion of automatic quantitative re-openers or off ramp provisions is an improvement over the past FEI and FBC PBR plans:

43.1 Please confirm or otherwise explain that an 'off ramp' may be distinguished from a 're-opener' in that it allows for all aspects of the PBR plan to be reviewed and possibly terminated, while a re-opener provides for a review of particular aspects of the PBR plan.

Response:

Confirmed. Please refer to FEI Application (Exhibit B-1), Section B6.7 where it is stated that related regulatory provisions "may vary from modification of a particular element of the PBR design (regulatory review, also known as a re-opener) to complete regulatory review or termination of the plan (also known as off-ramps)". This is the Utilities' understanding of these terms; however, in practice there is sometimes a blurring of the lines between them.

43.2 Please confirm that the 'off-ramp' and 'complete regulatory review' references to the proposed plans allow for all aspects of the PBR plan to be examined and possibly terminated.

Response:

Confirmed.

43.3 Please confirm that 'automatic quantitative re-openers' means that an application by a stakeholder is not required for the review to be undertaken in the event of a trigger.

Response:

Confirmed. FEI's and FBC's financial off-ramp is an example of an automatic quantitative off-ramp provision.

43.4 Under what circumstances and with what processes could a stakeholder trigger a complete review of the PBR plan.

Response:

The option available for stakeholders to trigger an off-ramp for review of the PBR plan would be with respect to sustained serious degradation of service. Please refer to the response to FEI-FBC BCUC PBR IR 3.25.1 in which FEI and FBC confirmed that the off-ramp related to unsatisfactory performance as measured by non-financial SQIs would only be addressed during the Mid-term Assessment Review.

The Utilities intend to work diligently to keep customer service at the target levels set out in the PBR, but if circumstances of serious sustained degradation of service occurred this could be raised by stakeholders in the Annual Review process. The Utilities are acting in good faith in these matters and will make every effort to address customer concerns about service quality when they are raised. Customers, as always, have the option to pursue these matters through the Commission.

43.5 Please confirm or otherwise explain that there none of the off-ramps represent an automatic termination of the PBR plan.

Response:

Confirmed. Off-ramps trigger a review process but the nature of the regulatory model that ensues from the review process would be subject to Commission approval. If an off-ramp has been triggered however, termination of the PBR plan is a possibility.

43.6 Please confirm or otherwise explain that the 'financial triggers' refers to the 200 basis point variance in ROE above or below the allowed ROE, and the 'non-financial' triggers refers to the serious degradation of SQIs.

Response:

Confirmed.

43.7 What other re-openers are included in AUC and other jurisdictions?

Response:

Please refer to Appendix D-1[5] of FEI Application (Exhibit B-1-1) for a review of the re-openers (off-ramps) included in Alberta and Ontario.

43.8 Would FEI and FBC consider intentional and/or material misrepresentation by FEI and FBC as justifying a reopening or off-ramp?

Response:

FEI and FBC are acting in good faith and the circumstance described will not arise. FEI and FBC accordingly decline to engage in this hypothetical assessment.

43.8.1 Please explain why or why not.

Response:

Refer to the response to FEI-FBC CEC PBR IR 3.43.8.

[5] Pages 10, 16 and 22.

43.9 Would FEI and FBC agree that an off-ramp including a 'material change in circumstances' could be valuable in permitting a review of the PBR plan in the event of unforeseen events that are not adequately addressed under application of the Z factor as a flow through?

Response:

A material change in circumstances that has not been considered either in the Companies' exogenous factor and flow-through provisions, and that is not currently contemplated, could be valuable. The Companies consider that the potential amalgamation of FEVI and FEW into FEI is foreseen and have already described an approach to incorporating these utilities into the PBR Plan. Please also refer to responses to FEI-FBC CEC PBR IRs 3.2.2 and 3.43.11.

43.9.1 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.43.9.

43.10 Would FEI and FBC agree that it would be incumbent upon the Commission to undertake a review of the PBR plan given a material event that was completely unforeseen and could not be adequately addressed within the plan?

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.43.9.

43.10.1 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.43.9.

43.11 Would FEI and FBC agree that a 'material change in service area', while not necessarily indicating a problem with the PBR process, could reasonably justify a complete review, and hence an 'off-ramp' because it could have a significant impact on the company?

Response:

As indicated in the question a material change in service area does not imply that there is something wrong with the PBR plan. For example FEU's proposed amalgamation can be incorporated in the current plan without any major change to the PBR design. In addition, Mid-term Review in FEI's and FBC's Applications is another safeguard mechanism where the Companies as well as the Commission can evaluate the potential impact of such events on the PBR plan and consider remedies to specific sections of the plan if needed.

For a discussion of the FEU's proposed amalgamation and its potential impact on the PBR plan, please refer to the response to FEI-FBC CEC PBR IR 3.2.3.

43.11.1 If not, please explain why not.

Response:

Please refer to response to FEI-FBC CEC PBR IR 3.43.11.

43.12 Please confirm that FEI would consider amalgamation with FEVI and FEW to represent a material change in service area and customer base.

Response:

Although this situation may represent a material change in service area and customer base, the existence of this known possibility should not affect the viability of the PBR proposal. The FEU do not consider the amalgamation to be cause for a complete review, considering that the rate base and cost of service of FEVI and FEW are already under the regulation of the BCUC and their operations and rate structures will be the same as those of FEI. In addition, the costs to undertake a complete review of the PBR Plan are unnecessary.

43.13 If amalgamation and postage stamp rates were to occur during the PBR period, would FEI propose to undertake a complete review of the PBR plan? Please explain why or why not.

Response:

No. The Commission has directed FEI to bring forward a PBR plan, and FEI is committed to doing so. The regulatory review process for putting that plan in to effect will be very significant in terms of effort for all stakeholders and cost to customers. It would be wasteful and unnecessary to proceed through this regulatory review process, only to change course less than a year later. Please refer to the response to FEI-FBC CEC PBR IR 3.2.3 for the FEU's proposal in the event of amalgamation and postage stamp rates. That proposal represents a workable and efficient approach to dealing with a favourable reconsideration decision

43.14 What impacts would FEI and FBC see in the event of amalgamation and postage stamp rates?

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.2.3.

44. Reference: FEI Exhibit B-1, Page 77 and FEI Exhibit B-1-1, Appendix D1, Page 22

> *6.7.2.1 Financial Trigger*
>
> Earnings-based trigger mechanisms, which are triggered if the actual ROE of the utility differs significantly from its approved ROE, is the most common form of off-ramp provisions. FEI is proposing that the PBR Plan be reviewed if the post-sharing achieved ROE of the Company exceeds or drops below the allowed ROE by 200 basis points in any single year of the PBR term.

> **Safeguard Mechanism (Off-Ramps and Re-Openers)**
>
> Originally Union's IR plan included an off-ramp provision. The provision specified that whenever weather normalized ROE was at least 300 basis points above or below the approved ROE, the Company would file an application with the Board for a review of the IR mechanism. In 2008, however, Union's actual ROE exceeded approved ROE by 330 basis points. This led to the elimination of Union's off-ramp provision, as well as the modification of the ESM to allow for earnings to be shared 90/10 when Union's actual ROE exceeded the approved ROE by 300 or more basis points.

44.1 Please confirm or otherwise explain that the ROE to which FEI and FBC's refer would be based on revenues that have been 'weather normalized.'

<u>Response:</u>

Confirmed.

44.2 Would FEI and FBC consider implementing an adjustment to the Earnings Sharing Mechanism rather than an off-ramp in the event the ROE exceeded the approved ROE by a pre-established amount? Please explain why or why not.

<u>Response:</u>

If circumstances lead to FEI's and FBC's financial off-ramp of +/- 200 basis points (after earnings sharing) being triggered this will lead to a full review of the PBR Plan. There are numerous potential outcomes for the resulting model after the off-ramp has been triggered, including the concept raised in the question. FEI and FBC both have experience with similar PBR models to those being proposed, including symmetrical 50/50 earnings sharing. FEI and FBC prefer their proposed approach for the financial off-ramp based on this past successful experience and the fact that triggering the off-ramp will allow the facts and circumstances in play at the time to be considered in establishing the path forward.

45. Reference: FEI Exhibit B-1, Page 78

> Finding the right balance between maintaining the PBR incentives and safeguarding the ratepayers and the Company is essential in design of the earnings-based off-ramps. The trigger point (the variance between earned and approved ROE) should be substantial enough to ensure that PBR's incentive powers are maintained (this is particularly important for a single year trigger point) and at the same time small enough to safeguard against potential excessive profits or losses. FEI believes that its proposed 200 basis point trigger achieves the appropriate balance[35]. B&V has discussed the considerations that go into the selection of an off-ramp in its PBR Report at p.9.

45.1 Please summarize all the considerations that go into determining the balance between maintaining the incentive powers and safeguarding against potential excessive profits or losses. Please address the issues that arise with a trigger point that is too low and a trigger point that is too high.

Response:

Conceptually, the balancing of customer and company interests in terms of trigger points for avoiding adverse financial outcomes should be set at parameters that protect both the shareholder from unreasonably low returns and customers from unreasonably high returns. The trigger point should also recognize that, if the threshold is set too low, there is a greater risk of triggering the off-ramp prematurely so as to put at risk continued achievement of some of the primary benefits of PBR.

The specific threshold proposed (+/- 200 bps) was a judgment call made by the Companies in consultation with B&V. The Companies were aware that the last FEI PBR used 150 bps (after-sharing) as the threshold, and came close to that level at one point in the course of generating benefits for the Company and customers. The Companies considered that the threshold could be increased to 200 bps in order to ensure that the plan would be able to continue to function and yield benefits for all stakeholders, without increasing the risk beyond an acceptable level for the Company (and customers, on the flipside). FEI considered that a threshold above 200 bps was higher risk than was appropriate.

Please also refer to the response to FEI-FBC CEC PBR IR 3.45.5.

45.2 Would FEI and FBC agree that a one year trigger point could be established at a higher rate than a two year trigger point to account for fluctuations in earning? Please explain why or why not.

Response:

Yes. As explained in the question preamble having a substantial trigger point is particularly important for a single year trigger point.

45.3 Would FEI or FBC object to a dual trigger point, such that a higher trigger point, such as 500 basis points, was established for a single variance, and a lower trigger point such as 200 basis points if the variance continued for two years? Please explain why or why not.

Response:

If the trigger points in the question of 500 basis points for a single year variance or 200 basis points for two successive years are meant to be more than hypothetical numbers, the Companies regard a 500 basis point trigger to be unacceptable, and inconsistent with an opportunity to earn a fair return.

FEI and FBC have two reasons why they would not support the two-year trigger concept as explained below.

- The Companies believe that a meaningful single-year trigger point would better protect the interests of the customers than dual trigger points. Dual trigger points may be prone to controversy for potential gaming concerns. To use the trigger points suggested in the question to illustrate, some may claim that a utility could decrease its expenditures in one year to achieve higher than a 200 bp variance (for instance 450 bp over the approved ROE) but increase expenditures for the next year to remain under the 200 bp trigger point. A single trigger point is less prone to this potential controversy.

- The Companies also intend to pursue efficiencies and savings on a consistent basis throughout the PBR term. To the extent that FEI and FBC are successful in this there should be a fairly steady trend in the growth in benefits and level of ROE achieved relative to the approved ROE. This means that if a hypothetical two-year trigger was set at a much lower level than the single year trigger (similar to the pattern in the question) there would be a high likelihood that if one year's results exceeded the two-year trigger level that the next year's results would too, causing the two-year off ramp provision to be triggered. Thus the two-year trigger would be likely to cut short an otherwise successful PBR and reduce the long-term benefits to be achieved under the plan.

45.4 Please provide the companies' actual ROE vs. forecast ROE for the last 10 years.

Response:

The actual and approved ROE's for FEI and FBC are provided below.

FEI - ROE

	Allowed (a)	Actual Pre-ESM (b)	Actual Post-ESM[1] (c)
2003	9.42%	10.23%	N/A
2004	9.15%	9.34%	9.25%
2005	9.03%	10.78%	9.91%
2006	8.80%	10.47%	9.64%
2007	8.37%	10.73%	9.55%
2008	8.62%	10.64%	9.63%
2009	8.99%	11.89%	10.44%
2010	9.50%	9.42%	N/A
2011	9.50%	10.15%	N/A
2012	9.50%	10.12%	N/A

Notes:
[1] Post-ESM only applicable for the years when FEI was under PBR (2004 - 2009)

FBC - ROE

	Allowed (a)	Actual Pre-ESM (b)	Actual Post-ESM[1] (c)
2003	9.82%	10.66%	10.88%
2004	9.55%	11.67%	10.70%
2005	9.43%	9.98%	9.88%
2006	9.20%	10.69%	9.94%
2007	8.77%	9.83%	9.23%
2008	9.02%	9.64%	9.28%
2009	8.87%	10.00%	9.41%
2010	9.90%	9.55%	9.65%
2011	9.90%	11.33%	10.67%
2012	9.90%	10.52%	N/A

Notes:
[1] Post-ESM only applicable for the years when an earnings sharing mechanism was in place (2003-2011)

45.5 Please summarize the reasons why FEI believes that its proposed 200 basis point trigger achieves the appropriate balance as opposed to a 100 basis point trigger point.

Response:

In general FEI believes the concept of triggering an off-ramp should be an exception rather than something that has a high probability of occurring. The PBR Plan should be designed so that it promotes the goal of pursuing efficiencies over the full term without triggering an off-ramp unless the exceptional circumstances of excessive profits or losses occur. The 100 basis point alternative threshold proposed in the question makes it more likely that the off-ramp would be triggered with the potential to cut short the achievement of longer term benefits that are the goal of PBR. By comparison the proposed 200 basis point (post-ESM) trigger will only be achieved if FEI is able to find much greater savings that will be benefit ratepayers going forward after rebasing.

The proposed trigger point at 200 basis points above or below the allowed ROE is already the narrowest when compared with its utility counterparts in Ontario and Alberta. FEI believes this is appropriate in the context of the overall risk / reward balance implicit in its PBR Plan.

Please also refer to the response to FEI-FBC CEC PBR IR 3.45.1.

46. Reference: FEI Exhibit B-11, BCUC 1.26.1

> With respect to the two items mentioned in the question, changes in the off ramps, other plan provisions the same, would likely be a more significant concern of the two. With off ramps, stakeholders are protected from outcomes that would otherwise not meet the standard that a utility be allowed a reasonable opportunity to recover its prudently incurred costs and earn the allowed return. Eliminating the off ramp or making it asymmetric by setting only an upper limit on the earned ROE without a floor would effectively make it necessary to have the X-Factor move in the direction of the industry average of minus four percent in order to meet the test of providing a reasonable opportunity to earn the allowed return.

46.1 Please explain why eliminating the off ramp or making it asymmetric by setting only an upper limit would require the X-factor to move toward industry average minus four percent.

<u>Response:</u>

B&V provides the following response.

The elimination of the off ramp or making it only available in over earning circumstances creates more risk related to the ability of the utility to earn its allowed return with an X-Factor well above the expected level of productivity for the industry. The only option for the utility would be to have a greater chance of earning the allowed return over the period by increasing the expected revenues.

XVI. REVIEWS - MIDTERM AND ANNUAL

47. Reference: Exhibit B-1, Page 81

Mid-term Review and Off Ramps	A midterm assessment review was held prior to the end of the third year of the PBR (2006). Any party could request a Commission review of the PBR Plan if the achieved ROE (after earnings sharing) was more than 150 basis points above or below the allowed ROE.	A midterm assessment review is proposed prior to the end of the third year of the PBR (2016). A review of the PBR Plan may be triggered by either a 200 basis point ROE variance above or below the allowed ROE, or sustained serious degradation of service quality as measured by the SQIs
Periodic Review	An annual review was conducted at the end of each year to provide a report on company performance.	An annual review is also proposed for this PBR.

47.1 Was degradation of the service quality indicators not assessed at the 2004 Mid Term review?

Response:

Service Quality Indicators were assessed as noted below in the Mid-term Assessment Review for the 2004 PBR Plan. There were no issues of service degradation as a result of this review.

The following is provided which is an excerpt from pages 3 through 5 of Section B8 of FEI's 2006 Annual Review and Mid-Term Assessment Review:

3. SERVICE QUALITY ASSURANCE

The PBR Settlement agreement includes a commitment by Terasen Gas to maintain existing high levels of service quality during the PBR term. Parties to the settlement agreed to specific Service Quality Indicators ("SQI") with benchmarks where applicable.

While delivering financial benefits to customers through built in productivity targets under the PBR formulae and further through shared savings on O&M and capital expenditures, there has been no adverse effect on Service Quality Indicators. All SQI benchmarks were materially met over the PBR period to date.

Operational performance indicators including call answer speed, billing accuracy and meter exchange appointments have exceeded the set benchmark. Customer satisfaction benchmarks measuring independently surveyed customer satisfaction levels and as well as the number of prior period adjustments for industrial transport service have improved during the PBR period. There has been no deterioration of system integrity measures for number of third party damages or leaks per kilometre of distribution mains.

Two measures have been slightly off benchmark targets but have shown improvement over the PBR period. Emergency response time has been nominally higher than benchmark, primarily due to increased traffic congestion and construction activity in the Lower Mainland. Throughout the PBR period this measure has never been more than 36 seconds off the benchmark. In 2004 and 2005, three reportable transmission system incidents occurred, exceeding the benchmark of two, by one incident. None of the reportable incidents were serious in nature. To date in 2006 there have been no reportable incidents.

Finally, the number of customer complaints to the BCUC has declined over the PBR period. The majority of complaints made have dealt with billing and collection matters which tend to spike during the heating season and around rate changes.

A summary of the Service Quality Indicators and benchmarks are provided in the tables below. Further details on SQIs can be found in Tab B-2 of this submission.

Service Quality Indicators and Benchmarks

	Performance Indicators	Benchmarks	2004	2005	2006 (Jan-Aug)
1	Emergency Response Time	<= 21.1mins	21.6mins	21.7mins	21.4mins
2	Speed of Answer - Emergency	>= 95.0%	97.9%	98.8%	99.0%
3	Speed of Answer - Non Emergency	>= 75.0%	77.5%	76.9%	77.9%
4	Transmission System Integrity	<= 2	3	3	0
5a	Res. & Comm. Customer Billing Activity	<= 5	1.93	1.97	0.70
5b	Industrial Customer Billing Activity	>= 99.5%	96.6%	99.9%	99.9%
6	Meter Exchange Appointment Activity	>= 92.2%	93.5%	94.3%	94.5%
7	Industrial Meter Measurement	>= 90.0%	98.0%	99.5%	99.2%
8	Customer Satisfaction	N/A-compare to prior years	75.3%	77.2%	77.0%
9	Customer Satisfaction (Customer Complaints to BCUC)	N/A-compare to prior years	191	121	114
10	Customer Satisfaction (# of Prior Period Adjustments)	N/A-compare to prior years	18	14	15

	Directional Indicators	2004	2005	2006 (Jan-Aug)
1	Number of Third Party Damages	1,492 incidents	1,457 incidents	1,023 incidents
2	Leaks per Km of Distribution Mains	0.0045 (150 leaks)	0.0034 (120 leaks)	0.0016 (58 leaks)

47.1.1 If not, please explain why not.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.47.1.

47.2 Please provide a list of the issues that were raised at the Mid-term review in the earlier PBR period, and by whom they were raised.

Response:

This response addresses FEI-FBC CEC PBR IRs 3.47.2 and 3.47.2.1.

FEI provides the following table which lists the issues that were identified in FEI's 2006 Annual Review and Midterm Assessment. The table also provides who raised the issue and how it was dealt with by the Province of BC in OICs 767, 768 and Vancouver Island Natural Gas Pipeline Special Direction No. 3; and BCUC in Order G 160-06 dated December 14, 2006. All of the issues dealt with would have been addressed as part of an Annual Review.

The Mid-Term Assessment Review materials were filed with the 2006 Annual Review materials and provided information on the PBR results-to-date, including financial results, earnings sharing and performance results under the SQIs. No issues arose with respect to the mid-term assessment review that required follow-up and the Commission determinations in BCUC Order G-160-06 did not include any items with respect to the Mid-term Assessment review.

	Issue	Annual Review (AR) or Mid-term Review (MR)	Raised By	How Dealt With
1	Approval of TGI & TGS amalgamation	AR	TGI	Approved per OIC 766, 767, 768 & Special Direction No. 3
2	Rate Base deferral to record costs related to amalgamation of TGI & TGS and to record O&M variance	AR	TGI	Special Direction No. 3
3	Cancellation of TGI Tariff Supplement I-3	AR	TGI	Cancellation approved by BCUC
4	Cancellation of TGS Tariff	AR	TGI	Cancellation approved by BCUC
5	Application of TGI Main Extension test to TGS current main extensions	AR	TGI	Denied, must use TGS MX test for main extensions in 2006 & prior years; TGI MX tests applies in 2007 for new main extensions
6	Amortization of TGS Intangible Plant, conversion costs of $777,000 over 10 years	AR	TGI	Approved by BCUC
7	Treatment of Pensionable Bonuses consistent with BCUC Decisions of 1992, 1994 & 2003	AR	TGI	Approved by BCUC
8	2007 Capital Structure & ROE – weighted average of TGI & TGS	AR	TGI	Approved per Special Direction No. 3
9	General Rate Reduction – delivery charges	AR	TGI	Approved by BCUC
10	Decrease RSAM rate rider	AR	TGI	Approved by BCUC
11	Set ESM Rate Rider	AR	TGI	Approved by BCUC
12	Deferral account to record SS Tax payment of $10 million. Part of $36 million SS Tax appeal	AR	TGI	Approved by BCUC
13.	Conservation Potential Review & DSM - Increased DSM Funding - Free rider on DSM initiative	AR	MEMPR BCOAOP	Denied by BCUC TGI ordered to provide RIM test, Participant Cost test, percentage of free riders for each program in 2006 & future reports
14	Comprehensive review of System Extension & Customer Connection Policies	AR	Commission	Commission directed TGI to conduct a comprehensive review of system extension & customer connection policy by 2nd quarter of 2007 for implementation in 2008
15	Depreciation & Overhead Capitalization Studies	AR	Commission	TGI ordered to suspend further expenditures on these studies
16	LNG Plant investment	AR	BCOAPO	Not addressed in Commission Decision

47.2.1 Please explain how each issue raised was resolved by the Commission.

Response:

Please refer to the response in FEI-FBC CEC PBR IR 3.47.2.

47.3 Please describe the differences in the types of process that would be undertaken, and the level of detail that would be provided in the mid Term review vs. the periodic Annual Review.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.48.6.

48. Reference: FEI Exhibit B-1, Page 69 and Page 78

Flow Through Expenses and Revenues	Revenues and non-controllable costs are forecast each year and flowed through in rates each year in the Annual Review Process.

34 Amortization of deferrals will be re-forecast at each Annual Review and actual amortization
35 expense each year will equal the approved amount.

1. Customer growth, volumes and revenues;
2. Year-end and average customers, and other cost driver information including inflation;
3. Expenses (determined by the PBR formula plus flow through items);
4. Capital expenditures (as determined by the PBR formula plus flow through items);
5. Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;
6. Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year
7. Service Quality Indicator results; and
8. Any proposals for funding of incremental resources in support of customer service and load growth initiatives.

48.1 Please provide a complete list of all the forecasts that will be reviewed at each Annual Review.

Response:

This response addresses FEI-FBC CEC PBR IRs 3.48.1 and 3.48.2.

Since the Annual Review will be setting rates on a forward looking basis for the coming year, all cost and revenue items in the revenue requirement calculations will of necessity be based on forecasts. This is the same in principle as what is done with a forward test period in cost-of-service rate setting. The PBR model changes the basis upon which the forecasts are made and the extent to which actual results affect the rate setting going forward within the PBR term.

Items 1 through 7 in the quote above provide a listing of many of the items that will be provided in forecasts at the Annual Review.

Generally, all items will be “trued up” for the historical actual (or projected) results, consistent with cost of service ratemaking, except for the items impacted by the two main incentive components (formula-based O&M and formula-based capital expenditures). These items will not be adjusted to actual during the PBR term (other than limited rebasing for capital if it is outside the +/- 10% dead-band in any year). Since capital expenditures are not rebased during the term, the forecast plant balances and resulting depreciation expense, capital cost allowance, and return on rate base for rate-setting (per Item 5 above) will be based on the formula-based capital expenditures carried forward for each year of the PBR.

48.2 Please flag in the list all the forecasts that will be 'trued up' to actuals.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.48.1.

48.3 Please identify all the inputs that will be based on actuals rather than forecasts.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.48.1.

48.4 Would FEI and FBC agree to have the 'true up' of forecasts to actuals be in-scope at the Annual Review?

Response:

At the Annual Review each year FEI and FBC will provide the relevant information on all cost-of-service components that are subject to adjustment or "true-up" for historical actual or projected results. Please note that the Annual Review will occur in the fall of the year so the Annual Review information on these cost items will be using projections to year end. The final adjustment to actual results will be made in the following year after the final year-end results are known.

Please also refer to the response to FEI-FBC CEC PBR IR 3.48.1.

48.4.1 If not, please explain why.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.48.4.

48.5 Would FEI and FBC propose to limit the Annual Review process to the issues itemized or would they be open to allowing the Commission to determine if an item should be added at the time of the Annual Review? Please explain why or why not.

Response:

The list of items quoted in the question preamble is intended to identify the major areas of information relevant to the functioning of the PBR that will be presented in the Annual Review materials. More detail will be provided in each of these areas. Once a PBR is approved and in place, FEI and FBC would expect the Annual Reviews to be limited to issues that are relevant to carrying out the PBR. FEI and FBC would expect that any request to raise issues would be subject to that proviso. If the Annual Review starts to take on extraneous and unrelated issues, or even begins to examine issues in unnecessary detail then a key purpose of establishing a PBR – reducing the regulatory burden of setting rates – is thwarted. Another objective of PBR, that of taking a more hands-off approach and providing the Utilities with the flexibility to pursue efficiencies in the manner they consider to be the most effective, may also be thwarted.

48.6 Please explain the ways in which the Mid Term review will vary from the Annual Review process.

Response:

The Annual Review for FEI and FBC will present the current year's projections and the upcoming year's forecasts for a number of key measures, including:

1. Customer growth, volumes and revenues;
2. Year-end and average customers and other cost driver information including inflation;

3. Expenses (determined by the PBR formula plus flow through items);
4. Capital expenditures (as determined by the PBR formula plus flow through items);
5. Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;
6. Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year;
7. Service Quality Indicator results; and
8. Any proposals for funding of incremental resources in support of customer service and load growth initiatives.

In addition, the Annual Review regulatory process will generally include a workshop, one round of IRs from the Commission and Interveners, letters of comment and a Commission determination of rates.

Please refer to FEI's Application (Exhibit B-1), Section 6.8 Annual Review, page 78 and FBC's Application (Exhibit B-1), Section 6.8, page 71 for discussion of the Annual Review process.

While the Annual Review is held every year during the term of the PBR Plan, the Mid-term Assessment Review will be held once as part of the third Annual Review. Additionally, whereas the Annual Review is focused on updating forecasts and reviewing the current year's results, the PBR Mid-term Assessment Review is intended to be a "checkpoint" to permit stakeholders to review the performance over the first three years and to address specific and discrete flaws with an otherwise workable plan. The Mid-term Assessment provides an opportunity for all the stakeholders to review the outcomes of the PBR and suggest adjustment to certain plan parameters (if required). This limitation is important. Off-ramps exist for more fundamental flaws with the PBR Plan as a whole, and short of triggering those off-ramps, the PBR Plan should be allowed to play out unless there is consensus that an element of the plan is capable of being improved for the mutual benefit of stakeholders.

Please refer to FEI's Application (Exhibit B-1), Section 6.7.1 Mid-term Assessment Review, page 76 and FBC's Application (Exhibit B-1), Section 6.8, page 69 for discussion of the Mid-term Assessment Review process.

XVII. OTHER

49. Reference: FEI Exhibit B1-1, Appendix D2, Page 2

NPV of Cost of Service Comparison of a $100,000 Capital Expenditure
($000)

Line	Average Depreciation Rate of 3.27%, 34 Year Evaluation Period[1]				
1	Original Year of Capital Addition[2]	2016	2017	2018	2019
2	Year of Deferred Capital Addition[3]	2019	2020	2021	2022
3	NPV Normal COS[3]	122.2	123.9	127.1	129.7
4	NPV Deferral COS[4] + PBR Earnings Sharing[5]	122.8	120.5	117.9	114.1
5	Net Change	**0.5%**	**-2.7%**	**-7.3%**	**-12.0%**

Notes:
1: The 34 year NPV is based on 31 years to fully depreciate the asset plus 3 years for the deferral
2: Year when capital was originally scheduled to be spent
3: Year when capital is spent after 3-year deferral
4: NPV of cost of service related to Original Year (Line 1)
5: NPV of cost of service related to Deferred Capital (Line 2)
6: PBR earnings sharing assumed for balance of the PBR term (i.e. through 2018)

49.1 Please confirm or otherwise explain that the purpose of the comparison was to illustrate the net change occurring from a capital expenditure deferred from within the PBR period to outside the PBR period.

Response:

Confirmed.

49.2 Please provide the full set of assumptions around which this table was derived including all the inputs for the derivation of the average depreciation rate, discount rate, calculation of the NPV Normal COS, calculation of NPV COS +PBR sharing.

Response:

The assumptions are provided in the footnotes in the quoted table above from FEI Exhibit B-1-1, Appendix D4, page 2 and in the text preceding the table in Appendix D4, page 2.

The average depreciation rate of 3.27% is based on the 2013 total depreciation expense divided by the 2013 Mid-year Gas-Plant-in Service (2012 - 2013 Revenue Requirements and Rates Application, May 4, 2011).

The discount rates used are based on FEI's weighted average after-tax cost of capital in rate base. The assumed capital structure, interest rates and ROE making up the WACC are listed in Attachment 49.4 provided in response to FEI-FBC CEC PBR IR 3.49.4 (see the "Inputs" tab).

Other inputs, assumptions and the NPV calculations can be found in Attachment 49.4.

49.3 Please explain how the model provides for the Efficiency Carry Over Mechanism

Response:

The results presented in the table from Appendix D-4, page 2 was a simplified illustration of the benefits of deferred capital, and did not provide for the effect of any specific ECM.

49.4 Please provide a working model for the above table, incorporating the effects of the Efficiency Carry Over mechanism and including the following:

- Original Year of Capital Addition 2014, 2015, 2016, 2017, 2018, 2019
- Actual Year of Capital Addition 2019 for every year
- Actual Year of Capital Addition based on deferrals of 1, 2, 3, 4 and 5 years.

Response:

A working model providing the requested analyses is found in Attachment 49.4. Please refer to the "Summary" tab for the overall summary of the results.

In summary the results of this analysis show that with the effects of the ECM included, the deferral of projects from within the PBR term to outside the PBR term, results in some additional costs being born by ratepayers (when the "net change" row becomes positive). This can been seen in the columns in the tables of the "Summary" tab where the original project year falls within the PBR term and the year in which the project proceeds falls after the PBR term. This result occurs primarily in the later years of the PBR term.

While project deferrals as noted may raise some concerns FEI does not believe that these findings negate the value of the PBR treatment of capital expenditures during the term and in the ECM. As FEI has noted in Appendix D-4 (with respect to FEI's 2004 PBR) and in other places the capital savings by FEI in the 2004 PBR term have been more in the nature of permanent reductions which yield ongoing benefits to customers. The incentive structure for capital in the 2014 PBR term and ECM period are designed to drive the Company with equal motivation throughout the PBR term to seek capital spending efficiencies. Not only will there be a reduced opening rate base from these cumulative efforts over the five year PBR term, there will also be a five-year history of year-by-year base capital spending that will provide a trend and base spending level for the annual capital expenditures going into the next revenue requirement period. FEI believes it is important that the PBR have a capital incentive with the degree of strength as proposed in the Application in order to motivate a vigorous pursuit of capital efficiencies and savings.

Finally, FEI has proposed the 10% deadband on capital expenditures to limit the potential impact of any concerns in this regard.

49.5 Please provide a working model demonstrating a deferred capital expenditure under PBR regulation and a similar deferred capital expenditure under Cost of Service regulation.

Response:

An Excel model is included as Attachment 49.5 which demonstrates the comparison of a two-year capital expenditure deferral under PBR regulation and Cost of Service regulation.

The hypothetical comparison is premised on a number of specific assumptions which lead to the result shown. The PBR example assumes a two-year deferral of the expenditure within the PBR term and includes the effects of the ESM during the PBR term and ECM afterwards. The Cost of Service regulation example assumes that the project was included in the approved capital expenditures in the first year of a two-year test period and was then deferred for two years (for unspecified reasons) and included again in the next test period. The example shows that PBR in this scenario has some advantages because of the shared impacts of ESM/ECM for both the deferral and later expenditure of capital.

50. Reference: FBC Exhibit B-10, CEC 1.15.1

> Based on the success of FBC's prior PBR Plan which included the same ESM (along with similar other PBR Plan elements), FBC believes that inclusion of the same 50/50 ESM in the 2014 PBR Plan is appropriate and will provide the Company with a consistent business case metric for pursuing additional efficiencies at all levels of ROE achievement (short of reaching the off-ramp). In addition, in comparison with other ESM designs, the symmetrical ESM better conforms to FBC's PBR principles. The Company believes it does a better job of aligning the interests of customers and the Utility than other ESM approaches, such as no earnings sharing or earnings sharing above or below a dead band, which are employed in other jurisdictions (see pages 36 and 37 of the Application). FBC's customers are sharing in efficiencies gained at all levels whereas this is not the case with these other PBRs. In other words FBC's customers will benefit from efficiencies as they are achieved rather than having to wait until the end of the term or until a certain ROE threshold has been exceeded.

50.1 Would FEI and FBC agree that a marginally attainable X factor and no Earnings Sharing Mechanism would equate to a higher risk, higher reward scenario for FEI and FBC, as well as for ratepayers? Please explain why or why not.

Response:

Yes. FEI and FBC agree that the X-factor and ESM options set out in the question would equate to a higher risk, higher reward (or loss) scenario for the Companies and customers, which the Companies do not believe to be a well-advised alternative.

B&V adds the following explanation. It is axiomatic that the efficiency discovery process necessary to achieve acceptable returns is risky in the sense that not all efficiency adjustments will result in savings. If the X-Factor is set too high with no ESM then the Plan does not meet the just and reasonable test of providing a reasonable opportunity to earn the allowed return. In that sense this is indeed a higher risk reward strategy for both customers and shareholders. This includes longer term risks for customers associated with higher capital costs that would result from an investment downgrade, impaired access to capital on reasonable terms in adverse market conditions, and also lower savings and higher rate increases at the next revenue requirement reset.

50.2 Please explain the risks that ratepayers and shareholders would face from such a scenario.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.50.1.

51. Reference: FBC Exhibit B1-1, Appendix D5, Page 3

FortisBC Inc.
2014 - 2018 PBR Plan
Illustrative Example of End-of-Term Efficiency Sharing Mechanism

Line No.	Particulars	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1	**Revenue Requirements Benefits for EOT Efficiency Sharing**										
2											
3	a). O&M Benefits achieved ($ Thousands)										
4	Allowed O&M per PBR formula (net of OH Capitalized)		$ 49,073	$ 49,366	$ 48,746	$ 49,879	$ 50,620				
5	Actual O&M		$ 48,500	$ 48,200	$ 47,200	$ 48,500	$ 49,000				
6	O&M Savings Achieved		$ 573	$ 1,166	$ 1,546	$ 1,379	$ 1,620				
7	**Incremental O&M Savings over prior year cumulative savings**		**$ 573**	**$ 593**	**$ 380**	**$ (167)**	**$ 241**				
8											
9	b). Capital Expenditures Benefits achieved ($ Thousands)										
10	Capital Expenditures allowed per PBR formula		$ 72,728	$ 69,087	$ 52,397	$ 53,632	$ 54,624				
11	Actual Capital Expenditures		$ 70,000	$ 70,500	$ 50,000	$ 52,000	$ 52,500				
12	Capital Expenditure Savings		$ 2,728	$ (1,413)	$ 2,397	$ 1,632	$ 2,124				
13	x Rate Base Benefit Factor		12%	12%	12%	12%	12%				
14	**Plant Additions Benefit**		**$ 327**	**$ (170)**	**$ 288**	**$ 196**	**$ 255**				
15											
16	c). Total Annual Revenue Requirement Benefits (Σ Lines 7+14)		$ 900	$ 423	$ 668	$ 29	$ 496				
17	**x 50% Earnings Sharing**	50.00%	**$ 450**	**$ 212**	**$ 334**	**$ 15**	**$ 248**				
18											
19											
20	Incremental Benefits Sharing for Phase-out ($ Thousands)										
21	1st Year - 2014		$ 450	$ 450	$ 450	$ 450	$ 450				
22	2nd Year - 2015			$ 212	$ 212	$ 212	$ 212	$ 212			
23	3rd Year - 2016				$ 334	$ 334	$ 334	$ 334	$ 334		
24	4th Year - 2017					$ 15	$ 15	$ 15	$ 15	$ 15	
25	5th Year - 2018						$ 248	$ 248	$ 248	$ 248	$ 248
26	Total Incremental Benefits Sharing		$ 450	$ 662	$ 996	$ 1,010	$ 1,258	$ 808	$ 596	$ 262	$ 248
27											
28	Rate adjustment permitted? (Y/N)		N	N	N	N	N	Y	Y	Y	Y
29											
30											
31	Revenue Impact of End-of-Plan Benefits Phase-Out ($ Thousands)							**$ 808**	**$ 596**	**$ 262**	**$ 248**

51.1 Please provide similar tables for both FEI and FBC for the previous PBR periods and carry over periods.

Response:

FEI has provided the Capital Efficiency ECM calculation below for its 2004-2009 PBR period as originally filed in FEI's December 2, 2010 Q4-2010 Gas Cost Report. O&M was not included in the calculation of the Efficiency Carryover Mechanism in the 2004-2009 FEI PBR.

		Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	2010	2011	2012
1	**Capital Efficiency Calculation**									
2										
3	Formula Base Capital Expenditure Spending (with Actual Customer adds)									
4	Customer Addition Driven CapEx	$24,283	$26,319	$21,896	$21,441	$20,133	$11,122			
5	Other Base Capital CapEx	67,361	69,090	70,588	72,278	73,595	74,756			
6	Total Base Capital Expenditures - Formula	91,644	95,409	92,484	93,719	93,728	85,878			
7										
8	Actual Base Capital Expenditures									
9	Customer Addition Driven CapEx	$21,896	$25,194	$28,820	$28,903	$32,288	$21,189			
10	Other Base Capital CapEx	48,717	50,840	55,269	44,417	57,859	67,320			
11	Total Base Capital Expenditures - Actual	70,613	76,034	84,089	73,320	90,147	88,509			
12										
13	Capital Incentive	$21,031	$19,375	$8,395	$20,399	$3,581	($2,631)			
14	Cumulative Capital Incentive for Phase-Out	$21,031	$40,406	$48,801	$69,200	$72,781	$70,150			
15										
16	Capital Incentive @ 14%	$2,944	$5,657	$6,832	$9,688	$10,189	$9,821			
17										
18	Customer Portion (50/50 during term. Total benefit less Phase-Out after)	$1,472	$2,828	$3,416	$4,844	$5,095	$4,911	$6,547	$8,184	$9,821
19										
20	Company Portion (50/50 during term. 2/3 & 1/3 Phase-Out in 2010 and 2011)	$1,472	$2,828	$3,416	$4,844	$5,095	$4,911	$3,274	$1,637	$0

FBC had neither a capital expenditure formula nor an Earnings Carry-Over Mechanism in its 2007 PBR Plan.

52. Reference: Exhibit B-10, CEC 1.29.3

> The ECM is symmetrical in its treatment of benefits and losses. If the benefits were lost in a subsequent year within the PBR term the effect of the loss would also be carried forward in the ECM for four additional years. There are two occurrences of this nature in the illustrative ECM example presented in Appendix D5, page 3. The first is where the hypothetical actual capital expenditures exceed the formula-allowed spending level in 2015 (see the 2015 column of line 12 of the table). The second case is in 2017 where the O&M savings vs. formula amount has lost ground relative to the cumulative savings that had been achieved in the prior year (see the 2017 column of line 7 of the table). Each of these two cases of missing the target has an implicit impact on the ECM that extends an additional four years beyond the initial year of occurrence.

52.1 Please provide an explanation as to why FEI and/or FBC missed the target in any years for which this occurred.

<u>Response:</u>

CEC IR 1.29.3 is discussing a hypothetical example. The years in which the O&M or capital targets are missed are included in the example for illustrative purposes only to demonstrate how the ECM would work if that was to occur.

52.2 Please provide a discussion of any strategies that FEI and FBC have to ensure that such occurrences are not repeated during the proposed PBR periods.

<u>Response:</u>

Please refer to response to FEI-FBC CEC PBR IR 3.52.1.

52.3 Please confirm or otherwise explain that FEI and FBC do not expect to miss the target during the PBR period.

<u>Response:</u>

In general FEI and FBC expect to meet, and hopefully do better than, the targets, provided the PBR plans are approved as proposed. However, the X factor proposed incorporates a significant implicit stretch factor already, given the industry TFP calculated by B&V. If adjustments are made such as setting a higher X-Factor value (greater than 0.5 percent) or reducing the 2013 base amounts to which the formula is applied, there is an increased possibility that the actual expenditures cannot remain under the formula-based amounts. FEI and FBC note that their proposed PBR Plans allow the Utilities to pursue overall efficiencies in the most effective manner, which may involve O&M / capital substitutions. If, for example, spending more on capital allows greater O&M efficiencies to be achieved for an overall better result, there is the possibility that capital expenditures could be over the target at times but with the additional benefit on the O&M side.

53. Reference: FBC Exhibit B-10, CEC 1.30.3

> FBC confirms that two new versions of the mentioned report were published by OEB's consultant on May and later on September 2013. The computed TFP values in the May 2013 version were increased from -0.05 and -0.03 % to 0.07 and 0.1% however the most recent version of this study (September 2013 version) which was updated with 2012 data is back into the negative values and indicates a negative TFP value of -0.33%. These changes (upward or downward) have no impact on the logic of the statement made on page 47. The values in all three versions are still significantly lower than the 0.72% TFP value approved for OEB's 3rd Generation IR. Therefore, FBC's position regarding the declining trend of TFP values since the year 2000 is still supported by PEG's reports.
>
> FBC cannot confirm the claim that one possible cause of this decline in TFP values is a change of data source from US data to Ontario data (this is not to say that a change of data source does not have any impact, positive or negative, on the measured TFP). The declining TFP

53.1 Please provide the full data set of the TFP values from each of the different TFP studies referenced as computed in all the different versions dating back to 2000. (i.e., September, 2013 (0.33%), May 2013 (0.1%)).

<u>Response:</u>

B&V and Utilities have only reviewed OEB's 4th and 3rd Generation Incentive Rate-setting and therefore can only provide the available PEG TFP studies that go back to 2008.

Report date	Title	Sample period	Sample source	TFP value	Link
September, 2013	Empirical research in support of incentive rate setting: 2012 update	2002-2012	Ontarian Utilities*	Negative 0.3	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379%202012_PEG_Report_on_Empirical_Work.pdf
May, 2013	Empirical research in support of incentive rate setting in Ontario.	2002-2011	Ontarian Utilities*	Positive 0.1	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_redline_20130531.pdf
September, 2008	EB-2007-0673, Supplemental report of the Board	1988-2006	American Utilities	Positive 0.72	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Supp_Report_3rdGen_20080917.pdf

** The Sample of Ontarian utilities used to calculate the TFP values did not include Hydro One and Toronto Hydro (the two largest electric utilities in Ontario). If these two utilities were included in the dataset, the TFP values would have been significantly lower than current ones.*

53.1.1 Please indicate which sources include Canadian information.

Response:

Please refer to response to FEI-FBC CEC PBR IR 3.53.1.

54. Reference: FBC Exhibit B-10, CEC 1.24.3

> The question is based on an incorrect assumption regarding FBC's evidence. FBC should and does undertake steps to operate efficiently, irrespective of whether the utility is under PBR. The difficulty under normal cost of service regulation, which PBR is designed to address, is that some efficiency measures cannot be undertaken without extending the period before rebasing occurs, because otherwise there is insufficient time for the utility to recover its incremental investment in efficiency. A utility is not under a duty to invest with an expectation of losing money; rather a utility has the right to expect an opportunity to earn a fair return on its investment.
>
> B&V adds that management has both a fiduciary responsibility to shareholders and an efficiency responsibility to customers. They exercise both with the former acting as a constraint of the latter. In addition, the expected earned return also acts as a constraint on efficiency improvements.

54.1 Please confirm that a utility has a duty to invest in all efficiency savings if it does not expect to lose money due to early rebasing?

<u>Response:</u>

FEI and FBC agree that a utility should be as efficient as possible however as explained by Wiseman and Pfeifenberger (2003) in their paper titled "Efficiency as a discovery process: Why enhanced incentives outperform regulatory mandates" (provided as Attachment 50.4 provided in response to FEI CEC IR 2.50.4 (Exhibit B-23)), incentives are generally superior to mandates for eliciting efficiencies and a firm cannot knowingly disavow or withhold efficiencies it has yet to discover. The following is an excerpt from the referenced paper:

> *"It is not uncommon in regulatory proceedings to encounter opposition to incentive regulation on grounds that utilities already have a statutory obligation to be efficient and, therefore, should not require additional rewards through incentive plans. At the crux of this argument are two key misconceptions. The first misconception is that a "mandate" to be efficient will produce the same long-term benefits as properly structured "incentives" to be efficient. The second misconception is the belief that regulated firms may knowingly and strategically disavow opportunities to increase operating efficiency under traditional regulation in order to profit from such innovation under incentive regulation … What this view fails to recognize, however, is that (1) the incentives requisite to the '**discovery'** of superior methods by which to augment efficiency are not sufficiently pronounced under cost-of-service regulation; and (2) the regulated firm cannot knowingly disavow what it has yet to discover. It is the recognition of efficiencies as a "discovery process" that largely explains the long-term benefits that incentive regulation offers over traditional cost-of-service regulation".*

54.2 Please confirm that there is nothing precluding FEI or FBC in a Cost of Service process from taking an application to the Commission to ask for relief relative to making efficiency investments that would be beneficial for customers but would otherwise compromise FEI's and FBC's ability to earn a fair return on the equity portion of any related investment.

Response:

Please refer to response to FEI-FBC CEC PBR IR 3.54.1.

55. Reference: Simplified PBR

55.1 Please comment on the potential for a PBR process which operated with a similar formula to the FEI and FBC proposal, but with no ECM and instead a requirement that efficiency sharing proposals be submitted to the Commission as required by the company with proposed sharing of earnings and reasons for sharing.

Response:

FEI's and FBC's proposed ECM is designed to eliminate the concern about investment timing during the PBR period from the decision making process regarding efficiency improvement investments and provide the Companies with an on-going incentive to operate efficiently throughout the entire regulatory period. The proposed alternative in the question fails to accomplish this objective.

In addition this proposal in the question is contrary to the principles of PBR related to allowing the utility to pursue efficiency benefits without micro-management of the Company through the regulatory process. This proposal has the impact of increasing the regulatory costs for reviewing any and all efficiency programs. In contrast to the notion of hands-off or light-handed regulation that is intended to accompany PBR, the approach proposed in the question goes in the opposite direction.

XVIII. FEI GAS

56. Reference: Response to data request CEC-1-31.4

56.1 The response to this data request was not fully responsive. Please provide the previously requested benchmarking studies.

Response:

In CEC's original question, FEI was asked if it participated in any natural gas detailed benchmarking studies with other natural gas utilities and if so could those benchmark comparisons be provided.

FEI's answer was that it does participate from time to time in surveys with other natural gas utilities but is not aware of those surveys being used as part of a PBR related natural gas detailed benchmarking study.

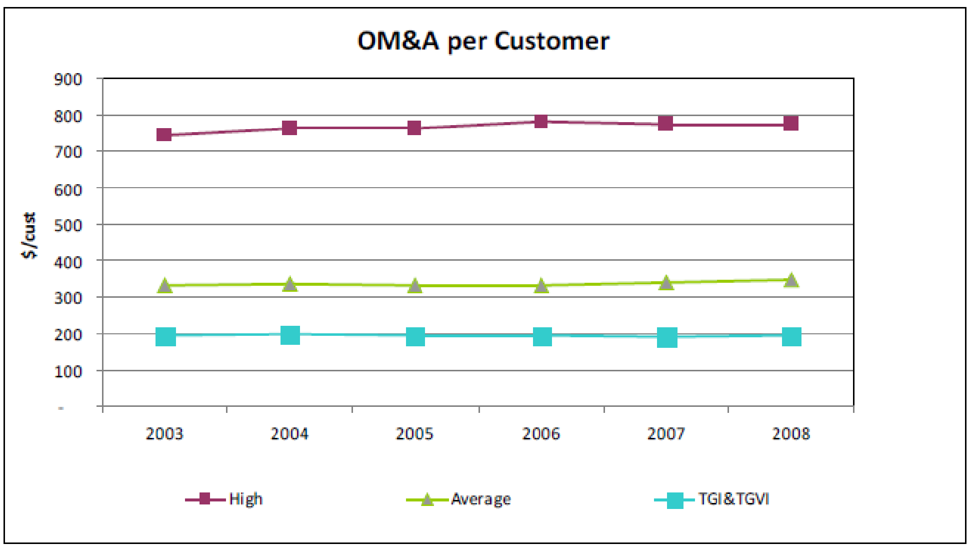
FEI clarifies the surveys it participates in from time to time recently include that with the Canadian Gas Association (CGA). FEI is a member of the CGA and participates in a benchmarking study comparing statistical, operational and financial metrics amongst the members. However, the study is owned by the CGA and is considered confidential by the CGA and not intended for use in regulatory or financial filings. As a result, the study cannot be provided.

Other surveys that FEI participates in include those related to customer service and market research. FEI participates in a survey comparing FEI's call centres performance against other North American call centres. This study is performed by SQM Group, a leading call centre research firm in North America. Similarly, FEI participates in customer research studies with E-Source, a research and advisory firm specializing in utilities and large energy users. These studies are considered confidential.

FEI references also an O&M per customer comparison to other natural gas utilities in Canada completed in 2009 and discussed on page 163 of the Terasen Gas Inc. 2010-2011 Revenue Requirements Application. An excerpt from that Application is provided here for reference.

Terasen Gas prides itself in having one of the lowest O&M cost per customer measures for natural gas utilities in Canada. A recent survey of comparable natural gas utilities in Canada (refer to Table B-1-14 below) based on publicly available information from regulatory filings and corporate annual reports ranks Terasen Gas including TGI and TGVI as one the lowest O&M (net of overhead capitalized) per customer out of eight companies surveyed. Due to the availability of data and for the purposes of comparison, a net of overhead capitalized O&M measure was used instead of a gross O&M measure excluding capitalized overhead.

Figure B-1-14: Terasen Gas is among the Lowest O&M per Customer



57. Reference: Response to data request CEC-1-37.3

"FEI cannot confirm that one possible cause of this decline in TFP values is a change of data source from US data to Ontario data."

57.1 Please acknowledge that the X factor in the OEB's 3rd Generation IR was based on a US MFP trend whereas the new X factor is based on an Ontario MFP trend.

Response:

Confirmed.

57.2 Please acknowledge that the output index in the Ontario MFP study places a heavy weight on system use output variables that are sensitive to local economic activity and growing conservation programs.

Response:

B&V provides the following response.

This cannot be confirmed. The use of kWh as an output measure is inconsistent with cost causation for delivery as discussed in detail in testimony and the evaluation of TFP studies. Second, the measure of capacity suffers from a further inconsistency with cost causation and an appropriate measure of capacity. While growing conservation programs may reduce kWh consumption, that impacts revenue recovery because of volumetric recovery of fixed costs, it says nothing about the impact on distribution productivity.

58. Reference: Response to data request CEC-1-42.2

"Under the economic definition of economies of scale, cost would decline as the number of customers and capacity increased for fixed technology and input prices…The utility industry does benefit from economies of scale in the sense that increasing the capacity of a pipeline from 2-inch to four-inch results in dramatically lower costs per unit of capacity (the scale economy concept)."

58.1 Please confirm that it is more correct to say that "Under the economic definition of economies of scale, UNIT cost would decline as the number of customers and capacity increased for fixed technology and input prices."

Response:

B&V provides the following response.

Confirmed.

58.2 Please confirm that economies of scale pertain to customer growth as well as capacity growth.

Response:

Confirmed, as stated in the referenced response.

58.3 Please confirm that the realization of scale economies is a potentially important driver of MFP growth in gas and electric power distribution, as it is in other industries.

Response:

Confirmed by B&V.

58.4 Please provide historical data on the number of gas and electric customers of Fortis in BC for as many years as data are readily available. Please also provide the best available forecasts of these customer numbers in the next 10 years (or as many years as are available).

Response:

FEI and FBC have provided historical actual average customers from 1993-2012. In addition, 2013 projected average customers and 2014 forecasted average customers have been provided for each Company from the material provided in this Application. The 2015 through 2018 forecasted customers that were included in the FEI and FBC Applications (Exhibit B-1), Section C1 have also been included in the tables.

FEI	1993 Actual	1994 Actual	1995 Actual	1996 Actual	1997 Actual	1998 Actual	1999 Actual	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual
Average Customers	642,442	665,805	685,400	703,231	720,464	734,152	745,234	755,079	760,236	766,929	770,624	779,461	791,593

FEI	2006 Actual	2007 Actual [1]	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual [2]	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Average Customers	802,743	816,427	825,696	832,751	839,017	845,282	834,888	840,720	845,496	850,621	856,002	861,403	866,682

Notes:
[1] - 2007 Customers include an increase of 3,352 customers upon the January 1, 2007 amalgamation of Terasen Gas Squamish and Terasen Gas Inc.
[2] - 2012 Customers adjusted by 14,892 as discussed in Appendix E4 of the FEI 2014-2018 PBR Application

FBC	1993 Actual	1994 Actual	1995 Actual	1996 Actual	1997 Actual	1998 Actual	1999 Actual	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 [1] Actual	2005 Actual
Average Customers	75,172	77,794	79,933	81,662	83,381	84,932	86,176	87,273	88,527	89,970	91,736	95,035	98,448

FBC	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Projected	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Average Customers	100,996	105,069	108,722	110,286	111,552	112,756	113,588	128,796 [2]	129,770	130,922	132,142	133,385	134,687

Notes:
[1] - The method of counting customers changed beginning in 2004, resulting in an increase of 2,260 direct customers in 2004.
[2] - 2013 Projected Customers adjusted for City of Kelowna additions

59. Reference: Response to data request CEC-1-81.2

59.1 Please confirm that these are the first two TFP studies that the authors have prepared.

<u>Response:</u>

Confirmed by B&V. TFP is a concept rooted in microeconomic theory and the authors have academic experience related to TFP concepts. They have extensive academic and hands-on experience in determining cost causation in the utility sector which is fundamental to undertaking a TFP study appropriate for a utility, rather than in the abstract.

59.2 Please confirm that these are the first two TFP studies prepared by the authors that have been entered in evidence.

<u>Response:</u>

Please refer to the response to FEI-FBC CEC PBR IR 3.59.1.

60. Reference: Response to data request CEC-1-81.9

The response did not fully respond directly to the question, which pertained to B&V's general statement that "As a practical matter, TFP signals whether costs are rising faster than the rate of cost inflation."

60.1 Please answer the general question, without reference to the Kahn method.

Response:

B&V provides the following response.

A negative TFP would mean that costs are rising faster than the rate of inflation, and if the X factor were set at zero so that rates would only rise at the rate of inflation then the Company would not have the ability to recover its revenue requirement.

60.2 Please confirm the general proposition that growth in the cost of a utility exceeds the growth in its input quantity by the growth in its input price inflation. Since inflation is typically exceeds 2% per annum, the growth in cost would be a grossly exaggerated measure of the growth in input quantity.

Response:

B&V provides the following response.

This statement cannot be confirmed as written because the quality of labor also changes as noted in the equation. Thus an FTE that moves from apprentice to fully-qualified based on the training received is effectively an increase in input that also increases the price of labor without changing the FTEs. This does not represent input price inflation because the input is more productive and is rewarded for that added productivity.

60.3 Please explain whether and how the "ex post measure" holds inflation constant, as suggested in the formula in the response.

Response:

B&V provides the following response.

There is no suggestion that inflation is held constant. The equation uses the price of labor in the current period consistent with the point of tangency between a short-run and long-run cost curve for a given set of technology and factor prices as required to define the cost curves.

61. References: Response to data request CEC-1-37.2

"The recession has no impact on the measure of output used in the TFP study"

The response to data request CEC-1-81.11:

"When the proposed PBR plan has a five year regulatory period it is asymmetric to use a longer period to assess productivity….Utilities' productivities are less affected by the economy because most of their costs are fixed and the response to an economic slowdown is much slower. Further, infrastructure replacement is critical to assure that a system is safe and reliable. Replacing plant during a recessionary period is also more economic and thus one would expect to see utilities investing in infrastructure to the extent permitted by existing financial conditions. With respect to input quantities other than infrastructure replacement as noted above, growth capital may decline but would be made up for by replacement capital. Distribution labor would not change significantly because that cost is relative fixed….Thus there is no bias in the selected period…B&V only collected data for the five year period because a longer period was not needed."

61.1 Please confirm that there is no logical reason to match the sample period for an indexing study with the expected length of the PBR plan. If you disagree, would you advocate a ten year sample period for a ten year plan?

Response:

B&V provides the following response.

This cannot be confirmed. The logic is sound that using a longer period for an indexing study cannot produce a reasonable expected TFP for a short period simply because the longer period is biased by technology and scale impacts that cannot be replicated in the near term.

A simple example illustrates this point. If you use a period of, say, thirty years to estimate efficiency improvements one of those improvements is the integration of the PC and software such as Excel into the rate case process. Prior to this time ratemaking relied on 14 column accounting paper to design rates and the work was done by hand. Changes required either correcting a sheet or redoing the sheet and were far more time consuming than entering the data and never printing the sheet until the results are correct. Since that productivity improvement would be factored in early in the period as an increase in TFP, that change cannot occur again and thus overstates the TFP over time. Further, long periods for calculating TFP assume implicitly that changes in costs and technical efficiency can be replicated again in the PBR period even if they have been fully adopted at the margin for all of the utilities. The concept of at the margin is particularly important because of the role of sunk costs and lumpy capital additions in effecting TFP in a short period such as the five year PBR Plan.

61.2 Please confirm that expenses for uncollectible bills and pensions and other benefits, both included in your study, could both rise rapidly during a recessionary period.

Response:

B&V provides the following response.

This cannot be confirmed. While the number of uncollectible accounts is likely to rise during a recession, the uncollectible accounts expense is not just a function of the number of accounts but also of the average amount written off. For example, the average price of natural gas for the period from 2008 has declined, meaning that it cannot be confirmed that the expense has risen rapidly. With respect to pensions and benefits expenses there are other factors that impact those costs other than the recession. These other factors would include the number of employees served under the plan, whether the plan was changed during this period (some companies changed their benefit plans to reduce their costs such as abandoning post-retirement healthcare). In summary there is no reason to believe that these costs rose more rapidly in the industry during the recession than in earlier years.

61.3 Please provide any evidence that these costs did NOT rise unusually rapidly.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.61.2.

61.4 Please confirm that DSM expenses may have grown rapidly during the sample period.

Response:

B&V provides the following response.

This cannot be confirmed. The growth rate in electric DSM expenditures for the industry was lower every year during the period than it was for the first year before the period with the exception of the last year and on average was lower over the entire period than in the first year before the period. The lowest growth during this period occurred between 2008 and 2009. The only data on gas DSM includes Canadian companies. With the exception of the first year of the study gas DSM costs increased less rapidly for each year of the period.

61.5 Please provide evidence that these expenses did NOT rise unusually rapidly.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.61.4. Attachment 61.5a contains a working spreadsheet from the EIA Electric Power Annual. Attachment 61.5B contains the AGA Natural Gas Efficiency Programs Report.

61.6 Please explain why delivery capacity and customer growth would not be slowed by a recession that dramatically impacted the real estate market.

Response:

B&V provides the following response.

Delivery capacity growth was indeed slowed by fewer customer additions as was the input requirements associated with that slower growth. Further, there was every incentive to improve efficiency during this period to improve earnings and avoid rate cases. The net result is that there is no reason to believe that productivity declined because of the recession.

61.7 Please provide any evidence that growth in capacity and the number of customers did NOT slow during the period.

Response:

B&V provides the following response.

The growth in customers and capacity was on average positive for the period. There is no suggestion that the growth accelerated during this period.

Please refer to the response to FEI-FBC CEC PBR IR 3.61.6.

61.8 Doesn't the argument above suggest that productivity growth WOULD slow during a recession if customer and capacity growth slowed?

Response:

B&V provides the following response.

No. Please refer to the response to FEI-FBC CEC PBR IR 3.61.7. It would be in the best interest of the Companies to increase productivity.

61.9 Please provide any empirical evidence supporting the notion that growth in replacement capex accelerated during the sample period.

Response:

B&V provides the following response.

For the electric industry, annual capital expenditures in each year of the period increased over the spending in each of the years prior to the period based on the SNL Report entitled Capital Spending included as Attachment 61.9. While these totals include spending on generation that is not part of the analysis, infrastructure spending on T&D has been cited as a significant driver of these costs. In addition, the net plant balances of all but two of the electric utilities in B&V's TFP study increased from 2007 to 2012, confirming growing capital expenditures in excess of annual depreciation expense.

In addition, please refer to the American Gas Association report (June 2012)[6] titled "Infrastructure cost recovery update" where it is stated that since 2007 the use of advanced regulatory mechanisms (such as capital trackers and surcharges) that allow for recovery of the costs of investments in utility replacement between rate cases have tripled:

> *"In 2007, when AGA published its first report on infrastructure cost recovery methods, 15 natural gas utilities in 11 states serving 8 million residential natural gas customers were using innovative rate structures that allowed them to modify tariffs and recover the costs of investments in utility replacement incurred between rate cases … Today, 47 utilities in 22 states serving 24 million residential natural gas customers are using full or limited special rate mechanisms to recover their replacement infrastructure investments, and 5 utilities have mechanisms pending in another state and the District of Columbia."*

[6] http://www.aga.org/our-issues/RatesRegulatoryIssues/ratesregpolicy/rateroundup/Documents/2012%20Jun%20Update%20%20Infrastructure%20Investment.pdf

62. Reference: Company's inflation measure proposal

62.1 Please estimate the share of direct labor expenses in the Company's total non-energy revenue requirement as calculated in the Company's most recent rate case.

Response:

This response addresses both FEI-FBC CEC PBR IRs 3.62.1 and 3.62.2

FEI defined direct labour expenses as the portion of total O&M related to labour, therefore the amounts can be directly referenced back to the financial schedules provided in Exhibit B-1. FBC also defined direct labour expenses as the portion of total O&M related to labour; however, as these amounts are not available in the financial schedules included in the FBC Application, FBC estimated the split of total O&M related to labour.

For simplicity, the analysis for both FEI and FBC excludes the impacts to both the income taxes and earned return from capitalizing the overhead in calculating the requested ratios. Additionally, the analysis excludes the impacts of any direct labour expenses which are directly capitalized.

For FEI, as shown in Table 1 below, approximately 19 percent of the Company's 2013 approved total non-energy revenue requirement was comprised of net direct labour expense while approximately 57 percent of the Company's 2013 approved total non-energy net O&M was comprised of net direct labour expense.

Table 1

	Revenue Requirement Parameters	Approved 2013	Non-Energy Related 2013		Remarks
1	Cost of Gas Sold	658,568	-		Ex. B-1, Section E, Sch. 3, Line 20
2	Direct Labour	135,064	135,064	A	Ex. B-1, Section E, Sch. 15, Line 6
3	Other Gross O&M	100,939	100,939	B	Ex. B-1, Section E, Sch. 15, Line 17
4	Capitalized Overhead (Labour Component)	(18,909)	(18,909)	C = A x 14%	Estimated Labour Component
5	Capitalized Overhead (Non-Labour Component)	(14,131)	(14,131)	D = B x 14%	Estimated Non Labour Component
6	Property and Sundry Taxes	51,239	51,239		Ex. B-1, Section E, Sch. 3, Line 25
7	Depreciation and Amortization	142,912	142,912		Ex. B-1, Section E, Sch. 3, Line 26
8	Other Operating Revenue	(24,789)	(24,789)		Ex. B-1, Section E, Sch. 3, Line 27
9	Income Taxes	28,049	28,049		Ex. B-1, Section E, Sch. 3, Line 31
10	Earned Return	216,404	216,404		Ex. B-1, Section E, Sch. 3, Line 33
11					
12	**Total Revenue Requirement: Approved and Adjusted**	**1,275,346**	**616,778**		Ex. B-1, Section E, Sch. 3, Lines 18 and 22
13					
14	**Total Non-Energy Revenue Requirement**		**616,778**	E	
15					
16	**Total Non-Energy Net O&M**		**202,963**	F = A+B+C+D	
17					
18	**Total Net Direct Labour in Revenue Requirement**		**116,155**	G = A+C	
19					
20	**Net Direct Labour as a % of Non-Energy Related Revenue Requirement**		**18.8%**	H = G/E	
21	**Net Direct Labour as a % of Net O&M Expenses**		**57.2%**	I = G/F	

For FBC, as shown in Table 2 below, approximately 12 percent of the Company's 2013 approved total non-energy revenue requirement was comprised of net direct labour expenses while approximately 54 percent of the Company's 2013 approved total non-energy net O&M were comprised of net direct labour expenses.

Table 2

	Revenue Reqirement Parameters	GCOC Approved 2013		Adjusted Revenue 2013		Remarks
1	**Power Supply**					
2	Power Purchases	91,942		[redacted]		Normalized out: Since Power Purchase related
3	Water Fees	9,871		[redacted]		Normalized out: Since Power Purchase related
4		**101,813**		**-**		
5	**Operating**					
6	O&M Expense (Labour Non Energy Component)	33,585		33,585	**A**	Estimated Labour O&M Non Energy Component
7	O&M Expense (Labour Energy Component)	772		[redacted]		Resource Planning Labour O&M - Considered Energy Related
8	O&M Expense (Non Labour Non Energy Component)	22,912		22,912	**B**	Estimated Non Labour Non Energy O&M Component
9	O&M Expense (Non Labour Energy Component)	352		[redacted]		Resource Planning Non Labour O&M - Considered Energy Related
10	Capitalized Overhead (Non Labour Component)	(2,305)		(2,305)	**C**	Estimated Non Labour Component
11	Capitalized Overhead (Labour Component)	(9,219)		(9,219)	**D**	Estimated Labour Component
12	Wheeling	5,233		5,233		
13	Other Income	(7,165)		(7,165)		
14		**44,165**		**43,041**		
15	**Taxes**					
16	Property Taxes	15,085		15,085		
17	Income Taxes	7,666		7,666		
18		**22,751**		**22,751**		
19	**Financing**					
20	Cost of Debt	42,377		42,377		
21	Cost of Equity	44,054		44,054		
22	Depreciation and Amortization	51,090		51,090		
23		**137,521**		**137,521**		
24						
25	Flow Through Adjustments	4,281		4,281		
26		**4,281**		**4,281**		
27						
28	**Total Revenue Requirement: Approved & Adjusted**	**310,531**		**207,593**		
29						
30	**Adjusted Revenue Requirement: Company's total Non Energy Revenue Requirement**			**207,593**	**E**	
31						
32	**Company's total Labour Component in Non Energy Revenue Requirement**			**24,366**	**F = A + D**	
33						
34	**Ratio of Non Energy Labour to Company's total Non Energy Revenue Requirement**			**12%**	**G = F/E**	
35	**Total Non Energy O&M Expense**			**44,973**	**H=A+B+C+D**	
36	**Share of Direct Labour in the Company's total non energy O&M Expense**			**54%**	**J = F/H**	

62.2 Please estimate the share of direct labor expenses in the Company's total non-energy O&M expenses as calculated in the Company's most recent rate case.

Response:

Please refer to the response to FEI-FBC CEC PBR IR 3.62.1.

Attachment 15.2

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 49.4

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 49.5

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachments 61.5A and 61.5B

61.5A - REFER TO LIVE SPREADSHEET MODELS

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(accessible by opening the Attachments Tab in Adobe)

Natural Gas Efficiency Programs Report

2011 Program Year

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INTRODUCTION

Awareness of the energy economy has steadily grown beyond the purview of business and public policy. Economic and environmental concerns have become increasingly important drivers of consumer decisions about energy. With this has come heightened attention to the potential for energy efficiency to moderate consumer cost increases, reduce greenhouse gas emissions and enhance energy security. For natural gas utilities, investing in energy efficiency programs presents an opportunity to achieve these objectives and benefit the communities they serve. Many have long-performing natural gas efficiency programs, and a number of them are working with their regulators to pave the way for new programs that will accelerate progress towards realizing a clean energy future while building sustainable value for utilities and their customers.

The *AGA Natural Gas Efficiency Programs Report - 2011 Program Year* presents data collected from members of the American Gas Association and the Consortium for Energy Efficiency on ratepayer-funded natural gas efficiency and conservation programs.[1] The report aims to portray the extent of this rapidly growing market in the United States and Canada and to identify practices and trends in program planning, funding, administration and evaluation.

This sixth annual study looks retrospectively at the status of the natural gas efficiency market in 2011, including expenditures and savings impacts, and presents a snapshot of budgets for 2012. Also explored are regulatory approaches to advancing the natural gas efficiency market. The findings illustrate how natural gas utilities have worked with their customers to help them reduce their carbon footprint and increase cost savings and with regulators to bring about progressive policies that support such initiatives.

An important contributor to this data gathering project is the Consortium for Energy Efficiency (CEE). The data collection effort has expanded significantly since AGA and CEE began coordinating efficiency data gathering in 2009. By joining forces, AGA and CEE have reduced the reporting burden for respondents, eliminated duplicative efforts for our organizations, and significantly enlarged the sample pool—extending the survey to more utilities in the U.S. and Canada and to third-party administrators of ratepayer-funded efficiency programs.

AGA would like to thank the members of AGA and CEE in the U.S. and Canada for participating in this important data-collection effort. We appreciate tremendously the time and effort given by all survey respondents throughout the information gathering process, including extensive clarification and data validation follow up. (See Appendix E for a listing of participating companies).

[1] CEE is an award-winning consortium of efficiency program administrators from the United States and Canada. Members work to unify program approaches across jurisdictions to increase the success of efficiency in markets. By joining forces at CEE, individual electric and gas efficiency programs are able to partner not only with each other, but also with other industries, trade associations, and government agencies. Working together, administrators leverage the effect of their ratepayer funding, exchange information on successful practices and by doing so achieve greater energy efficiency for the public good.

Executive Summary

In 2012 the American Gas Association (AGA) and the Consortium for Energy Efficiency (CEE) surveyed their U.S. and Canadian members and other efficiency program administrators on the status of their 2011 *ratepayer-funded* natural gas efficiency programs, including low-income weatherization. Based on survey findings for the 2011 program year:

- Natural gas utilities continue to help their customers to reduce energy usage and lower their annual energy bills by investing in successful and innovative efficiency programs, which include cash rebates and financial incentives, low-income specific programs, strategic partnerships, joint programs with other electric and gas utilities, efficiency loans, education campaigns, targeted marketing, energy audits, whole house projects, and customized retrofits of large facilities.

- Natural gas utilities fund 134 natural gas efficiency programs—128 in 39 states and six in Canada.

- Residential natural gas efficiency program participants in the U.S. saved on average 13 percent of household gas usage or about 99 Therm per year, averaging $107 in cost saving on their annual energy bill.

- In the United States, utilities invested nearly $958 million in efficiency programs in 2011. They also budgeted nearly $1.4 billion for the 2012 program year (which represents a growth of 46 percent compared to 2011 spending levels).[2]

- In North America (U.S. and Canada), natural gas efficiency program spending approached $1.1 billion in 2011. Program budgets are set at about $1.5 billion for the 2012 program year (projecting a 43 percent increase in spending).

- U.S. spending on evaluation, measurement and verification activities approached $15.5 million in 2011, and it is estimated to reach $34.5 million in 2012 (a 123 percent increase).

- On a revenue basis, median spending for utilities on efficiency programs was 1.5 percent of net natural gas distribution revenues in 2011 (i.e. net of gas costs)—ranging from less than 0.1 percent to 15 percent of net revenues.

- In 2011 U.S. customers saved 125 trillion Btu through natural gas efficiency programs, thus offsetting 6.5 million metric tons of carbon dioxide (CO_2) emissions (a 55 percent increase from the 80.8 trillion Btu achieved in 2010).

- In North America (U.S. and Canada), natural gas savings impacts from efficiency programs approached 204 trillion Btu in 2011—the equivalence of 10.6 million metric tons of avoided CO_2 emissions (a 51 percent increase from the 135 trillion Btu achieved in 2010).

- Seventy-six percent of rate-payer funded programs provide natural gas efficiency programs to low income customers, and 70 percent of all programs provide low- or no-cost weatherization assistance.

[2] The survey samples for 2011 expenditures and 2012 budget are similar but not identical.

- Twenty-six states require utilities to fund natural gas efficiency programs, and 27 states mandate that they implement weatherization and/or energy efficiency programs specifically for low-income customers.

- Thirty-eight states permit utilities to recover natural gas efficiency program costs, 31 allow them to recoup lost margins related to program implementation, and 18 approve financial incentives to reward efficiency program implementation or performance.

- Recovery of natural gas efficiency direct program costs are allowed via the following mechanisms:

    - special tariff or rider in 26 states
    - base rates in 16 states
    - system benefits surcharge in eleven states
    - deferral accounts in eleven states
    - other mechanisms in two states

- Twenty-seven percent of regulator-approved natural gas efficiency programs permit fuel switching, and 14 percent measure efficiency from the energy source to the usage site by applying a full fuel cycle analysis.

METHODOLOGY AND SURVEY SAMPLE

In 2012 the American Gas Association (AGA) and the Consortium for Energy Efficiency (CEE) surveyed their U.S. and Canadian members and a few other entities on the status of their 2011 *ratepayer funded* natural gas efficiency and low-income weatherization programs.[3] These include utility and non-utility, or third-party, efficiency program administrators.[4] In this report, the term "natural gas efficiency program" refers to a set of activities designed to promote a cost-effective and prudent approach to energy usage, including low-income single and multi-family home weatherization, indirect impact activities (such as conservation education, energy audits and contractor certification), and direct impact activities in new and existing buildings and homes (e.g., equipment replacement and Energy Star Homes[5]).

The sample frame consists of all member organizations of AGA and CEE and nonmember organizations identified as large program administrators. The response rate from natural gas efficiency program administrators was 96 percent (based on our current knowledge of existing active programs). Thus natural gas efficiency statistics may be slightly understated in this report. Responses were received for 128 programs, implemented in the U.S. and six in Canada.

The survey asked respondents to describe their natural gas efficiency programs during the 2011 calendar year or coinciding program year for which data were available, including program expenditures and energy savings. Also 2012 data were collected on efficiency program budgets and estimated participant counts.

Two versions of the survey were distributed: a short form was distributed to CEE utility members and administrators of statewide energy programs, and a long form was distributed to all AGA utility members. The short form focuses mainly on natural gas efficiency program funding, energy savings and products, and the long form questionnaire covers program planning and structure, funding and savings, evaluation, and regulatory treatment. The beginning of this report and part II represent all data collected data via both short and long forms, while the remainder of the report discusses responses from the subset of companies that completed the long form (113 companies in the U.S. and three in Canada).

The utilities represented in this report operate within natural gas service territories in 39 states and in Canada. They account for 80 percent of the natural gas delivered to consumer by gas distribution companies in the United States and have an aggregate annual throughput of 10.7 trillion cubic feet (Tcf).[6] These companies serve more than 52 million residential customers, corresponding to 79 percent of the U.S. residential natural gas market.

Not all reporting companies answered every survey question. Therefore the response sample varies question to question. Because the sample pool is not normalized and varies year to year, this report does not directly compare 2011 with prior year data, except for illustrative purposes. Tables and charts generally represent a simple tally of the responses to the survey questionnaire.

Report footnotes and section introductions provide additional information regarding methodology.

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[3] Because a number of low-income weatherization programs that are run by state agencies do not participate in this survey, report data tend to understate low-income program expenditures and budgets.

[4] Appendix E lists the companies represented in this report, including those that did not respond directly but whose data were provided by a third-party administrator. While only national aggregates are presented in the report, Appendix B, C and D present expenditure and budget data by state and region and energy savings data at the region level.

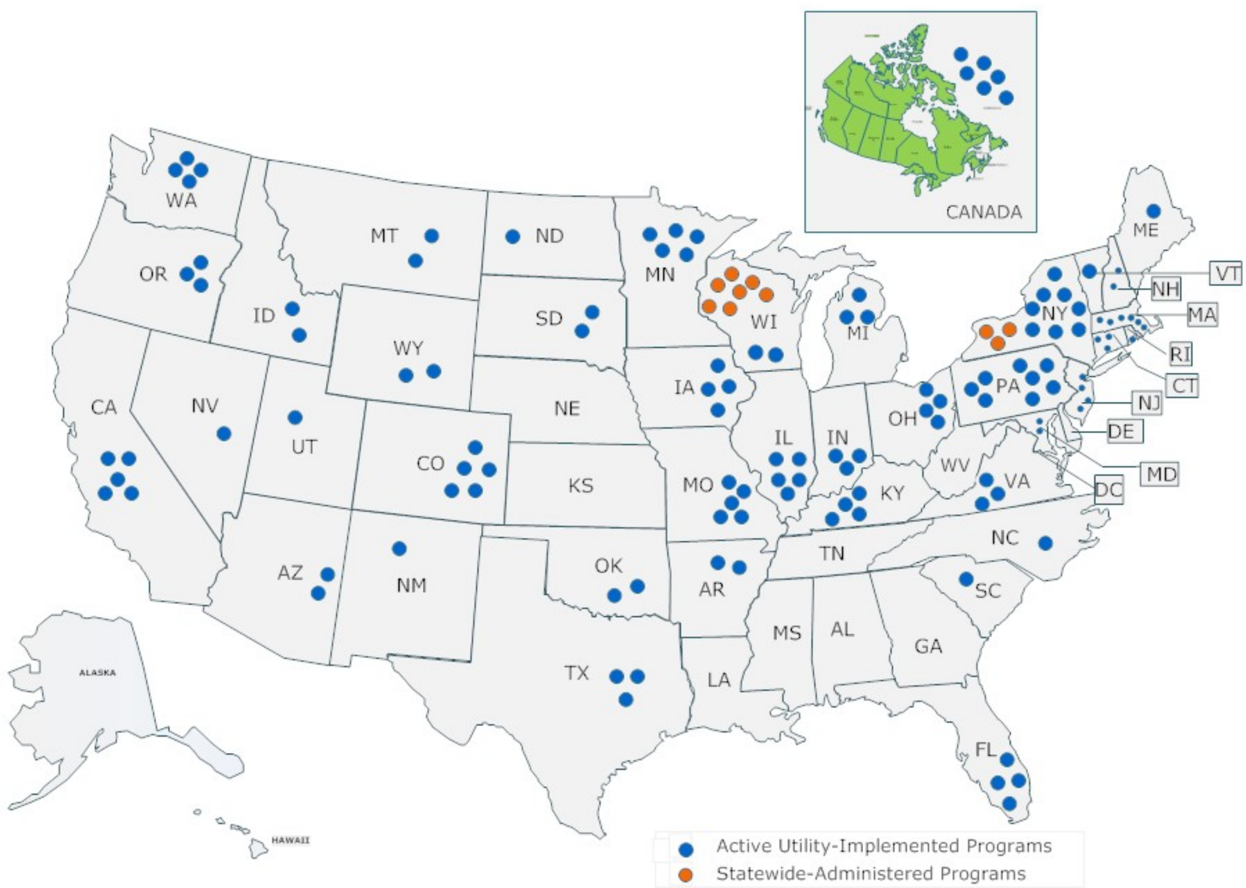
[5] A more detailed description of energy efficiency program activities can be found on page 15.

[6] Based on the Energy Information Administration's *Natural Gas Annual Respondent Query System* (EIA Form 176, Data through 2011), Release Date: November 2012

I. NATURAL GAS EFFICIENCY PROGRAM CHARACTERISTICS

According to 2011 program year data, there are at least 134 active natural gas efficiency programs in North America[7]—128 in the U.S. and six in Canada—that are funded by local natural gas utilities (see Figure 1).

Figure 1



The 128 U.S. programs include 124 that are administered by utilities (in part or whole) and ten that are implemented solely by a statewide energy program administrator, such as Efficiency Maine, Energy Trust of Oregon, Illiniois Deparment of Commerce and Economic Opportunity, New Jersey Clean Energy Program, New York State Energy Research and Development Authority (NYSERDA), Public Interest Energy Research (PIER) program in California, and Wisconsin Focus on Energy. Twenty-two of the 124 utilities fund third-party administered programs in conjunction with their own utility-implemented programs; however, to avoid double-counting, these are counted once in this report.

[7] In this report, North America refers to the United States and Canada.

Program Structure and Administration

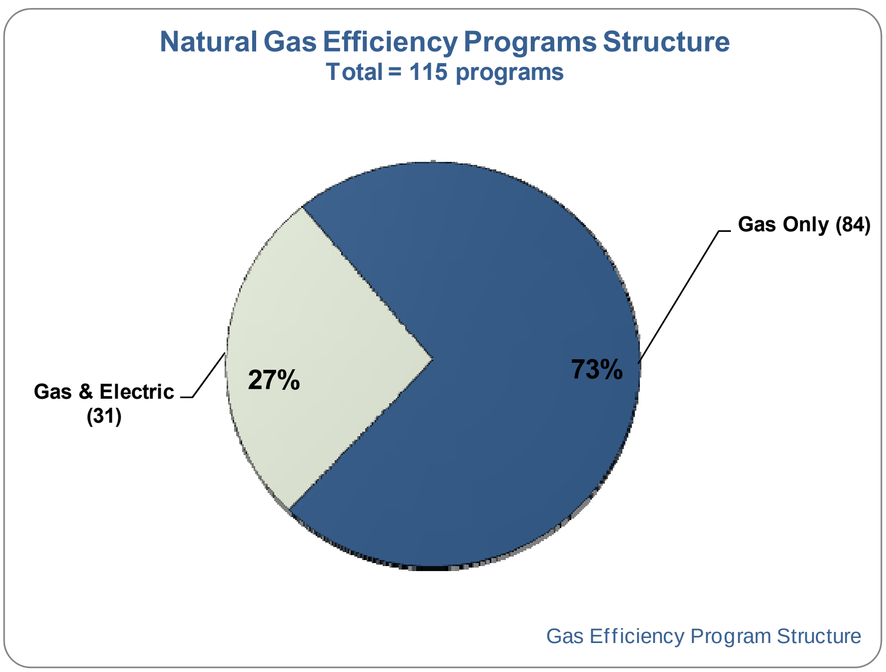
From this point forward (except for part II, which focuses on funding and savings data for all survey respondents), this report describes a subset of ratepayer-funded natural gas efficiency programs for which a full set of qualitative data was obtained. This subset comprises 116 programs (113 in the U.S. and three in Canada) funded by the ratepayers of 70 natural gas distributors, 44 combination gas-electric utilities, and two municipally-owned utility (see Table 1).

Table 1

Natural Gas Efficiency Program Implementation by Utility Type 116 programs		
Company Type	**Programs**	**Percentage**
Investor-Owned Natural Gas Distributor	70	60%
Investor-Owned Combination Gas & Electric Utility	44	38%
Municipally-Owned Gas Utility	1	1%
Municipally-Owned Combination Utility	1	1%

The majority of natural gas efficiency programs (84 of 115) are administered as natural gas-only programs, while 31 are implemented jointly with electric efficiency programs (see Figure 2).

Figure 2



While many natural gas efficiency programs have been in place for years, they continue grow. Programs generally range from the newly launched to mature programs that span 20 or more years (see Table 2). Forty-two percent of programs have been in place ten years or longer, and half of those have operated for at least 20 years. The other 58 percent were implemented within the last 10 years, and the median program age is five years. Nine percent of programs were launched in 2010 and 2011.

Table 2

Natural Gas Efficiency Programs Since Inception 115 Programs	
Years in Service	**Number of Programs**
Less than 1 (2011 start)	3
1 ≥ < 10	64
10 ≥ < 20	24
20 or more	24

Forty-seven percent of natural gas efficiency programs (53 of 113) expanded since the 2010 program year. Utilities accomplished this by revising conservation improvement plans, setting higher energy savings targets, increasing funding and participation levels, and accessing new markets and customer segments (particularly residential and low income, and some expanded to all rate classes). They also hired more staff (e.g. marketing and engineering), forged new partnerships (such as community weatherization programs and delivery integration with electric programs), and bolstered marketing efforts to promote programs (such as energy audits, financing and rebates) via direct mail campaigns, community education, and outreach engagements.

Many added new programs such as C&I custom solutions, commercial energy audits, commercial kitchens, re-commissioning, small business, direct install, deep energy retrofit, multi-family, and new builder programs. They also added existing whole house performance, home energy consultations, behavioral change, low income propane-to-gas conversion, zero percent on-bill repayment, and pre-weatherization programs. Some initiated new rebate programs, while others boosted existing incentives by adding qualifying equipment and increasing rebate amounts. They also put in place larger incentives for higher efficiency equipment, for measures geared toward whole-house efficiency (e.g., seal up rebates), and for fuel switching to gas appliances.

Many pilot programs were launched in 2011, including home conservation through combined audits and rebates, residential and C&I whole home, behavioral change, multi-family efficient equipment, better building, school education, and high efficiency appliance rebates. Survey respondents also added many custom and prescriptive measures, such as roof top HVAC, condensing unit heaters, kitchen equipment (including commercial variable speed hood), super-high efficiency furnaces, faucet aerators, air curtains, boilers, clothes dryers, and tank and tankless water heaters.

Program Administration: A diverse group of parties administers natural gas efficiency programs. Sixty-seven percent (77 of 115) are administered by the utility alone and three percent by a nonprofit organization. Another 28 percent are managed by a utility working with other groups, and two percent are run by two or more non-utility entities, such as a non-profit working with a government agency (see Table 3).

Among the other parties cited as working with the utility are statewide program administrators, private energy efficiency consultants, third-party program implementers, incentive fulfillment administrators, energy evaluation contractors, engineering firms, government agencies, cities and counties, and non-profit community action agencies that deliver low-income programs.

Table 3

NATURAL GAS EFFICIENCY PROGRAM ADMINISTRATORS 115 PROGRAMS		
	PROGRAMS	PERCENTAGE
Utility-Administered	77	67%
Nonprofit Organization	6	3%
Utility Working with Other Entities	29	28%
Two or More Non-Utility Entities	2	2%

When the utility serves as program administrator, non-evaluation program functions are carried out by in-house staff in 53 percent of programs (56 of 106) and by a third party in 5 percent (or 5 programs). The other 42 percent (45 programs) are jointly implemented by utility employees and a third party. (The *Program Planning and Evaluation* section discusses the assignment of evaluation functions).

In some utility-implemented programs, specialized staff is fully dedicated to energy efficiency projects, while in others employees charge a fraction of their time towards energy efficiency functions. For example, instead of full-time employees, marketing and/or rates staff might undertake efficiency-related tasks.

A calculation of full-time equivalent (or FTE) staff represents the combined hours applied to energy efficiency projects, divided by the number of hours in a standard work day for a given program year. Based on 94 responses, the number of internal FTE staff involved in energy efficiency projects ranges from 0.1 to 332 employees; however, the median number of FTE per utility efficiency program is three. Table 4 classifies programs according to FTE size and shows the number and percentage of programs that falls within each FTE category.

As shown in Table 4, 73 percent of natural gas efficiency programs have fewer than five full-time staff equivalents, and only five percent of programs fall within the 50 or more FTE category.

Table 4

Utility-Administered Natural Gas Efficiency Program Staff 94 Programs		
Full Time Equivalent Staff	**Programs**	**Percentage**
One or Less	28	30%
1 > < 5	40	43%
5 ≥ < 10	10	10%
10 ≥ < 25	10	11%
25 ≥ < 50	2	2%
50 or more	5	5%

Program Coordination and Delivery Partnerships: Sixty-five of 111 respondents (57 percent) either coordinate or jointly implement specific programs with other utilities and organizations. More than half of the 65 respondents work with electric, gas or combination utilities to achieve consistent program offerings or delivery and reduce implementation costs, thereby benefitting customers. These collaborations take the form of common program implementation, specific joint activities or sponsorships, or they may involve a division of functions between the parties with each responsible for different components.

In many states utility collaboratives are mandated; however, in others partnerships are voluntary. In certain jurisdictions, utilities are required to fund a statewide energy efficiency program (see examples on page 5), while in others they coordinate among themselves, with or without a common implementation vendor. Some of the utilities that fund statewide programs leverage them by offering free home energy audits and enhanced rebates to statewide program participants. Some present their customers with the option of selecting between statewide program rebates *or* utility financing, while others coordinate with the statewide program administrator to target distinct markets and avoid duplicative efforts.

In other jurisdictions, utilities (gas and electric) often share the planning, marketing, website, evaluation, and/or reporting components of their programs. Many utilities coordinate specific efficiency measures and/or fund particular programs that benefit their mutual customers, while others coordinate with adjacent service territories. Certain partnering utilities include both gas and electric savings measures in their school education energy kits or address both fuels during an energy audit.

Examples of coordinated or co-delivered programs include home energy audits, residential direct install, Energy Star New Homes, commercial new construction, C&I retro-commissioning, multi-family, school education, and residential and small commercial pilot programs. Other examples of utility partnering are cost sharing, incentive processing, co-branded bill inserts, referral exchanges between gas and electric utilities, uniform rebates, contractor training, joint advertising, efficiency data sharing, co-filing plans with the regulatory commission, and co-sponsoring efficiency outreach events.

Utilities also work with nonprofits, including community action agencies, conservation consultants, and city, county and state agencies. With the community action agency (CAA), utilities perform referral exchanges and joint assessments of low-income customers. They may also either coordinate energy audits and weatherization activities, or they may reimburse the CAA for installation services, approved equipment, and/or administrative costs. Many of these measures and services are free to the income-qualified customer.

Trade allies form another vital partner to the utility in raising customer awareness and delivering efficiency products and services. Many program managers recognize the necessity to engage, incentivize and train trade allies in transforming the market. Eighty-four percent of respondents (95 of 113) indicated that they partnered with one or more parties in the market supply chain during the 2011 program year. Of the 95 programs, 96 percent partner with contractors, 75 percent with retailers, 59 percent with equipment distributors, and 32 percent with manufacturers (see Table 5).

Table 5

Natural Gas Efficiency Partnerships with Trade Allies 94 Programs		
Trade Partner	**Number of Programs**	**Percentage**
Manufacturers	30	32%
Equipment Distributors	56	59%
Retailers	71	75%
Contractors	91	96%
Other	12	13%

While 14 percent of respondents partner only with contractors, the rest have relationships with more than one supply chain partner. In fact, 24 percent are involved with all four trade allies. Also 13 percent engage other market players, such as architects, engineers, realtors, landlord businesses, training professionals, appliance leasing companies, authorized dealer networks, trade associations, municipalities, and community interest groups.

Utilities combine efforts with trade professionals who sell, install or service equipment to drive energy awareness, promote efficiency programs, and make energy efficiency products more accessible to customers. Auditors, HVAC, plumbing, window, and insulation contractors become trade allies of the utility to be visible partners with the program. Trade allies also serve as a communication channel to customers, informing them about efficiency program incentives and in some cases processing rebates directly. Often they work with the program administrator on the application process, savings calculations and eligibility verification. Commercial technologies are also marketed via trade allies.

Relationships with trade partners vary from informal conversations via direct mail, brochures, home shows, and websites to formal arrangements, such as trade agreements, contractor and authorized dealer networks, and trade ally focus groups. Utilities provide members of their trade ally networks efficiency education, program-specific information (e.g., rebates, application process), and marketing materials (e.g., point of purchase displays, tear sheets, brochures, mailers, and signage at retailers and contractors). Many utilities and their partners co-brand promotional materials and share advertising costs with dealers and retailers.

Utility efficiency programs sponsor or co-sponsor technical training, offer incentives or subsidies to contractors that attain required certifications, and provide website directory listings. Many programs also offer incentives and bonuses for the sale or installation of high efficiency equipment as well as ongoing technical and sales support.

Some utility efficiency programs have dedicated trade relations and program managers who actively engage in direct outreach to trade representatives and maintain relationships with contractors and others via regular meetings, workshops, ongoing support, and marketing at trade shows. Community outreach specialists communicate with and educate customers, trade groups and other community members via presentations, seminars, community events, and municipal meetings (e.g., environmental commission). Others provide program collateral to local agencies that provide other services to income-qualified customers. Still others coordinate with their statewide efficiency program administrator by leveraging their rebates with complimentary incentives, such as zero percent financing.

Program administrators also employ other strategies or novel approaches to transform the market. Some provide instant rebates at the point of purchase or through contractors to encourage customers, or they may offer customer discount cards on efficient products and services at participating local retailers. Others target upstream market adoption by incenting manufacturers and distributors to stock and up sell the highest energy efficiency equipment available to the mid-stream and down-stream markets. In a similar vein, some give added incentives to tankless water heater manufacturers.

In other cases, the utility partners with contractors to facilitate the installation of needed infrastructure that supports natural gas delivery to new construction and renovations, with the focus of stimulating economic growth in their community. In such cases, authorized dealer network members may replace water heaters and/or repair or replace customer-owned gas piping. Some utility programs also work with contractor networks and box retailers (e.g. Lowes, Home Depot) to promote the sales of efficient natural gas appliances and products (e.g., water heaters, programmable thermostats). They also work with landlords by offering them revert agreements that automatically transfer the account back to the landlord when the tenant vacates.

Generally the relationship between efficiency program and trade partners presents mutual promotional opportunities. Basically program administrators are able to target a wider market segment via trade allies and are able to have an influence on the types of energy efficiency products that are made available to energy consumers. In turn, by working with efficiency program administrators, retailers and dealers benefit from increased sales through enhanced marketing and lowered up-front cost for the customer. Contractors also benefit their business through technical training, increased visibility and customer referrals from participating contractor portals or online efficiency directory listings.

Efficiency Program Objectives

When asked to select all goals that drive their natural gas efficiency programs, respondents answered as follows: 113 of 115 target direct impact on energy savings, 89 engage in behavioral change (via education, training or direct outreach to customers and others), and 64 seek market transformation (through manufacturers, distributors, retailers and consumers of energy-related products and service). Also 30 aim for avoided emissions and 15 pursue job creation (see Table 6).

Table 6

Purpose or Goal of Natural Gas Efficiency Programs 94 programs with one or more goals		
Goal	**Number of Programs**	**Percentage**
Direct Impact on Energy Savings	113	98%
Behavior Change	89	77%
Market Transformation	64	56%
Direct Impact on Avoided Emissions	30	26%
Job Creation	15	13%
Other	11	10%

Eleven respondents also cited the following goals: stimulate economic development, support government policy (e.g., low income), and improve cost-effectiveness (e.g., by adding natural gas HVAC as a measure to meet gas-electric efficiency goals). They also sought to provide additional services to customers and to assist low-income customers via weatherization services, thus reducing their energy burden, minimizing payment arrears, and lowering utility uncollectible balances. Others aimed to moderate growth in electricity consumption and dependence on other fuels and to reduce peak and off-peak electric generation needs, thus mitigating transmission infrastructure investments.

Customer Segments and Participants

Respondents were asked to identify all customer segments in their efficiency programs. Ninety percent (103 of 114) have residential efficiency programs, 76 percent have low-income, 77 percent have commercial/industrial (C&I), and eleven percent have separate industrial programs. While 60 percent of programs include all three customer segments (68 of 114), eight have only residential, nine only low-income, and one has only a C&I program.

Participant counts were obtained for 105 active natural gas efficiency programs in 2011, and estimated participant counts were gathered for 99 programs for the 2012 program year. Not all programs track or report participation rates or the number of enrollments. In cases where respondents do not actively monitor participants, some provided estimates. Others track the number of paid rebates or grants instead of participating customers. Still others differ on whether to count online audits, behavioral conservation program reports, home savings evaluations, or students participating in school-based education programs. The numbers in Table 7 reflect these discrepancies and thus participant figures should be considered as very rough estimates.

During 2011, enrollments in natural gas efficiency programs reached more than 2.9 million residential customers, nearly 400 thousand low-income participants, and 65 thousand C&I

customers. Nearly two thousand customers enrolled in separate industrial programs. In a few cases, programs had low to no participation in 2011 due to late program implementation and ensuing ramp up period. Table 7 shows participant counts for 2011 and estimates for 2012.

Table 7

Program Participants by Customer Segment				
	Residential 92 Programs	Low Income 71 Programs	C&I 76 Programs	Separate Industrial 9 Programs
2011 Program Year	2,949,853	399,623	65,227	1,860
2012 (Estimated)	3,214,849	228,739	74,347	669

According to reported counts, participation increased 22 percent in residential program from the 2010 program year (from 2.4 million participants), decreased 7 percent in low income programs (from 430,913), decreased 56 percent in C&I programs (from 148,127), and increased 4 percent in separate industrial programs (from 1,931 participants).

Participants per program vary widely. During the 2011 program year, the median participant count for residential programs was 3,830, ranging from as few as 123 to as many as 502,980 customers. In low-income programs, with a range of one to 136,347 participants, the median count was 190. C&I programs had from one to 12,223 accounts, and the median participant count was 148, while separate industrial programs enrolled from four to 1,148 participants, with a median of 110 participants.

Respondents were asked to assess customer behavior and participation relative to the prior program year. Sixty percent of respondents (65 of 109) indicated that participation increased during 2011, 26 percent (or 28 respondents) said that it decreased, while 15 percent (16 respondents) found no change in participation.

While some observed slight to moderate increases in participation across customer classes, others reported the opposite trend, with processed rebates declining among all rate classes. A number of administrators with multi-segment programs saw participation in their residential and low income programs expand, while their C&I programs contracted; however, just as many saw the reverse pattern.

On the upside, respondents cited the following factors as drivers for participation: larger budgets due additional regulator-approved funding, enhanced outreach and marketing efforts, increased awareness, new program offerings coming online including new rebate programs, higher incentive amounts and tiered efficiency incentives, combined C&I gas and electric projects, and an ability to complete more jobs per year.

On the other side, many respondents attributed decreased participation—particularly in residential programs—to the elimination of federal (and in some instances state) efficiency tax credits in 2011. This situation was compounded by a sluggish economy, high unemployment, and low gas rates. Other causes for lower participation numbers include changes in reporting cycles from program to calendar year, reduced advertising and communication, phasing out of specific programs (to comply with regulatory order in some instances), redesigned programs that required a ramp up period, depletion of low income funds, and decreases in commercial boiler tune-ups.

The American Reinvestment and Recovery Act (ARRA) received mixed reviews. Some believe that ARRA caused contractors to divert their attention away from utility funding to take advantage of these temporary federal funds before they expired. Other respondents remarked that fewer homes were weatherized in 2011 due to the depletion of ARRA funds along with new rules that make it more difficult to make use of DOE weatherization assistance program (WAP) monies.

Respondents were also asked to describe whether customer behavior changed in any significant manner during 2011 and to share their thoughts on possible contributing factors. While some shared an optimistic outlook, others were not as sanguine. A number of respondents find their residential customers to be more “efficiency minded”—i.e., they are more aware of energy costs, weatherization measures, and program offerings. One program tracked efficiency optimization (EO) awareness and found a 12 percent increase in overall customer awareness, with 73 percent aware of available EO options. Another program found that approximately 80 percent of customers participating in their conversion loan program selected a high-efficiency central heating furnace. Also another program reported that 86 percent of rebated furnaces were 95 percent AFUE or higher compared to 80 percent the prior year. Respondents correlate positive results with education and outreach efforts as well as trade ally activity.

Others attribute increased conservation to poor economic conditions, the impact of ARRA funds, and a warmer winter. Yet these same conditions (the economy and mild weather)—coupled with lower natural gas prices—are cited by a number of respondents as having contributed to customers' lack of urgency in pursuing energy efficiency investments. According to some, commercial customers increasingly repair HVAC equipment rather than purchase a replacement, and residential customers are more cautious about incurring new home expenditures and extended term financing.

Low Income Programs

As mentioned earlier, 76 percent of natural gas efficiency programs provide conservation or energy efficiency activities to low income customers (other than education, counseling and online tools). When asked whether they had income-specific efficiency programs, 75 percent of respondents (86 of 115) indicated that they had a set of efficiency programs exclusively available to their low and limited-income customers. These income-qualified programs are independently administered by the utility in 26 percent of programs (22 of 86), by a community action agency in 21 percent (or 18 programs), by the state in eight percent (7 programs), and by another organization in six percent (or five programs). The remaining 40 percent (34 programs) are jointly implemented by two or more entities.

The following organizations are also involved in low-income programs: non-profit agencies, third-party implementation contractors, state environmental and energy resource agency, state mortgage finance authority, city housing network, university outreach group, churches, cities and counties.

Income-specific efficiency programs generally present qualified renters and home owners with solutions that reduce their energy burden by helping them manage their energy usage and save money on their monthly energy bills. Utilities direct their low income activities toward single and/or multi-family housing in new construction or retrofit programs. Examples of such programs include municipal housing, affordable home retrofit programs and new affordable housing programs.

Some of these coordinated efforts involve the utility working with non-profit community action agencies (CAA) to leverage both the CAAs' grassroots networks and federal weatherization funding, thereby providing a more comprehensive set of measures and accessing a larger number customers in this hard-to-reach distressed market segment. Some utilities work with non-profits that provide housing, rehabilitation and energy programs to low income and transitional populations, thus allowing them to expand their low income services into efficient equipment installation and improved insulation. Additionally, several utilities that do not administer their own low-income efficiency activities support statewide energy efficiency low-income programs.

Some programs offer low-cost measures to customers based on income qualifications, either by following federal poverty level guidelines or by using a lower poverty threshold to expand the pool of eligible customers. In some cases, incentives are offered to near low-income (just above the federal standard) or moderate income customers. Many programs cover 100 percent of the *incremental* cost of converting to higher efficiency appliances, while others pay 100 of retrofit costs capped at a set dollar amount per residence. Others provide a fixed dollar amount per specific measure or cover a significant portion of the equipment replacement cost. In other cases, emergency equipment replacement is coupled with weatherization, and in a few cases, a portion of health and human safety measures and/or repairs are also covered under the low-income program.

While some programs offer financial incentives as well the above-mentioned services to low income customers, often these direct rebates are inadequate to incent customers at a certain poverty level to make home efficiency improvements; therefore, many low income programs are offered at *no cost* to the household. Besides weatherization services (e.g., air and duct sealing, roof and floor insulation, appliance and pipe wrap), these no-cost programs may include the replacement and installation of high efficiency natural gas furnaces, boilers, dishwashers, clothes washers, water heaters (storage, tankless and solar), and/or cooking ranges. Also included in many no-cost programs are window replacements and programmable thermostats.

Many utilities also offer bill payment assistance in the form of hardship funds, discounted rates, and arrearages forgiveness. Others offer fuel conversion programs to income-eligible customers.

Energy Efficiency Activities and Products

Survey respondents were asked to identify all efficiency components they offered in each of four customer segments. According to 116 responses, one or more efficiency activity is offered in 103 programs to the residential single family segment, in 93 programs to the residential low income segment, in 85 programs to the C&I segment, and in 76 programs to the residential multi-family segment. Based on these responses, when taking into account indirect impact activities, 80 percent of programs provide conservation and/or energy efficiency activities to low income customers (see Table 8).

Table 8 breaks down responses by customer segment and energy efficiency activity. Residential single family efficiency programs enjoy the most comprehensive set of efficiency activities, followed by residential low income, residential multi-family programs, and commercial/industrial.

A look at specific efficiency activities shows that education outreach is most adopted across segments, particularly in the residential single family and C&I segments (84 percent and 63 percent, respectively). Examples of such "indirect impact" activities include school education programs, brochures, and bill inserts. Also widely prevalent are direct impact activities in existing homes or buildings—in 78 percent of residential single family, 67 percent of commercial/industrial, 65 percent of low income, and 59 percent of multi-family programs. These direct impact activities include equipment replacement and upgrades (e.g., appliances, doors, windows, and thermostats), building retrofits, commercial food service, process equipment, energy management systems and custom process improvements.

Weatherization is the third most common component of natural gas efficiency programs—offered in 70 percent of low income programs and 54 percent of residential single family programs. These weatherization activities incorporate building shell insulation and air sealing of ducts and wall cracks.

Table 8

UTILITY-IMPLEMENTED NATURAL GAS EFFICIENCY PROGRAM ACTIVITIES BY CUSTOMER SEGMENT
116 reporting programs with one or more efficiency activity

ENERGY EFFICIENCY ACTIVITIES	RESIDENTIAL SINGLE FAMILY 103 PROGRAMS	RESIDENTIAL MULTI-FAMILY 76 PROGRAMS	RESIDENTIAL LOW INCOME 93 PROGRAMS	C&I 85 PROGRAMS
Weatherization	63	45	81	
Indirect Impact Programs				
Certification	25	19	25	13
Education	97	66	72	73
Online Tools	68	47	46	50
Technical Assessment	62	45	52	53
Training	48	37	36	45
Direct Impact Programs – Existing Buildings	90	68	75	78
Direct Impact Programs: New Construction/Expansions	61	41	31	48
Other	7	6	7	3

While not as prevalent as existing building retrofit programs, the other regular feature in efficiency programs is the direct impact new home/building program—employed in 53 percent of residential single family and 41 percent of C&I programs. Such direct impact activities encompass energy efficient homes, efficiency design assistance and industrial efficiency.

Many programs also include other types of indirect impact activities, such as online tools (e.g., energy usage and savings calculators) and on-site energy audits (in 53 percent of single family programs and 46 percent of C&I programs). These programs tend to be low cost relative to other programs. Efficiency training and certification (of contractors, installers and building operators) tend to lag somewhat compared to other programs. Technical training is provided in 41 percent of single family, 39 percent of commercial/industrial, and 32 percent of multi-family programs. Professional certification is offered in 22 percent of residential single family and of low income programs, 16 percent of multi-family programs, and 11 percent of C&I programs.

A relatively small number of respondents selected "other" energy efficiency activities. This includes school efficiency education (some of which include direct install efficiency kits), natural gas safety inspections, and behavioral change programs.

ENERGY EFFICIENCY PRODUCTS: Respondents were asked to identify all products (equipment and comprehensive projects) included in their natural gas efficiency programs (in this case during the 2012 program year) and to indicate whether they recognize different efficiency performance levels and vary incentives accordingly (based on either equipment or overall project efficiency levels).

Based on the answers of 118 respondents, standard products in residential natural gas efficiency programs are furnaces (92 percent of programs overall), storage water heaters (80 percent), boilers (74 percent), tankless water heaters (64 percent) and weatherization products other than windows (61 percent). Similarly, in the commercial segment, boilers are most common (72 percent), followed by furnaces (69 percent), storage water heaters (66 percent), tankless water heaters (58 percent), and HVAC control upgrades (54 percent). Custom programs are most offered in separate industrial segment (in 36 percent of efficiency programs overall). Table 9 depicts survey responses by program segment and product and service category and shows the number and percentage of programs in each segment and product category that enhance incentives with increased product efficiency.

Table 9

PRODUCTS INCLUDED IN NATURAL GAS EFFICIENCY PROGRAMS – 2012
118 PROGRAMS

PROGRAMS, PRODUCTS AND SERVICES		PROGRAMS OFFERING THIS PRODUCT		PROGRAMS THAT MATCH LARGER INCENTIVES WITH HIGHER EFFICIENCY PERFORMANCE		
		PROGRAMS	PERCENTAGE	RESPONSES	PROGRAMS	PERCENTAGE
RESIDENTIAL						
HVAC	Furnaces	108	92%	106	62	58%
	Boilers	87	74%	85	43	51%
	Quality Installation	32	27%	31	6	19%
	Tune Ups	37	31%	36	7	19%
	Controls Upgrade	53	45%	52	9	17%
	Direct Heating: Hearth Products	9	8%	9	3	33%
	Direct Heating: Wall Furnaces	16	14%	16	4	25%
	Direct Heating: Room Heaters	8	7%	8	1	13%
APPLIANCES	Dishwashers	14	12%	14	3	21%
	Clothes Washers	25	21%	25	4	16%
	Clothes Dryers	16	14%	16	2	13%
WATER HEATERS	Storage	94	80%	92	42	46%
	Tankless	76	64%	74	23	31%
	Solar Thermal	8	7%	8	2	25%
WINDOWS	Any Product	29	25%	29	5	17%
WEATHERIZATION	Any Products Except Windows	71	61%	70	22	31%
WHOLE HOME	New Construction	54	46%	53	34	64%
	Retrofit	51	43%	50	23	46%
OTHER		28	24%	28	3	11%

Table 9 continued

Programs, Products and Services		Programs Offering this Product		Programs that Match Larger Incentives with Higher Efficiency Performance		
		Programs	Percentage	Responses	Programs	Percentage
Commercial & Industrial						
HVAC	Furnaces	82	69%	81	61	75%
	Boilers	85	72%	84	61	73%
	Quality Installation	17	14%	16	7	44%
	Tune Ups	47	40%	46	12	26%
	Controls Upgrade	64	54%	63	23	37%
	Gas-Fired Packaged Unitary Equipment	32	27%	32	13	41%
	Unit Heaters	46	39%	46	23	50%
Appliances	Dishwashers	22	19%	21	13	62%
	Clothes Washers	31	26%	30	11	37%
	Clothes Dryers	19	16%	18	10	56%
Water Heaters	Storage	78	66%	77	40	52%
	Tankless	68	58%	67	29	43%
	Solar Thermal	16	14%	16	8	50%
Kitchens	Any Product	62	53%	62	22	35%
Whole Building	New Construction	45	38%	45	33	73%
	Retrofit	44	37%	44	30	68%
Energy management	Any Product	44	37%	44	6	14%
Combined Heat & Power	Any Installation	15	13%	15	11	73%
Separate Industrial Segment						
Plant Assessments		32	27%	31	11	35%
Prescriptive (Any Product)		32	27%	32	20	63%
Custom (Any Product)		43	36%	42	29	69%
Continuous Energy Improvement or Strategic Energy Mgmt.		21	18%	21	11	52%
Other		18	15%	17	4	24%

Other products listed by 18 respondents, included in the residential category, are direct install water-saving measures such as faucet aerators and low flow shower heads, hydronic boilers, cooking ranges, programmable setback thermostats, drain water heat recovery, web-based and onsite energy audits, behavioral savings projects, appliance retention (natural gas to natural gas), replacement of inefficient appliances with more efficient natural gas appliances, and approved natural gas piping.

For C&I programs, other products listed include water saving devices (including low flow spray nozzles and pre-rinse spray valves), onsite audits, behavioral change, agriculture programs, financing (including shared savings financing), chillers, infrared heaters, cogeneration allowance, steam traps, retro-commissioning, gas conversion prescriptive rebate, benchmarking with portfolio manager, cost share for certification, modulating burners, vent dampers, primary air dampers, natural gas vehicles, and HVAC and water heating as a custom measure conditioned on demonstrated savings.

Often measures are eligible if the savings are verifiable. Many custom programs base incentives on annual energy usage reductions. Also many projects must be cost effective to be eligible. As shown in Table 9, many programs follow a tiered approach to appliance or whole project efficiency, recognizing the varying efficiency performance levels within each product category. Accordingly, these programs match financial incentives to the equipment's efficiency rating or the project's overall efficiency performance, instead of applying a flat incentive to all equipment models or efficiency projects that fall within a given efficiency threshold.

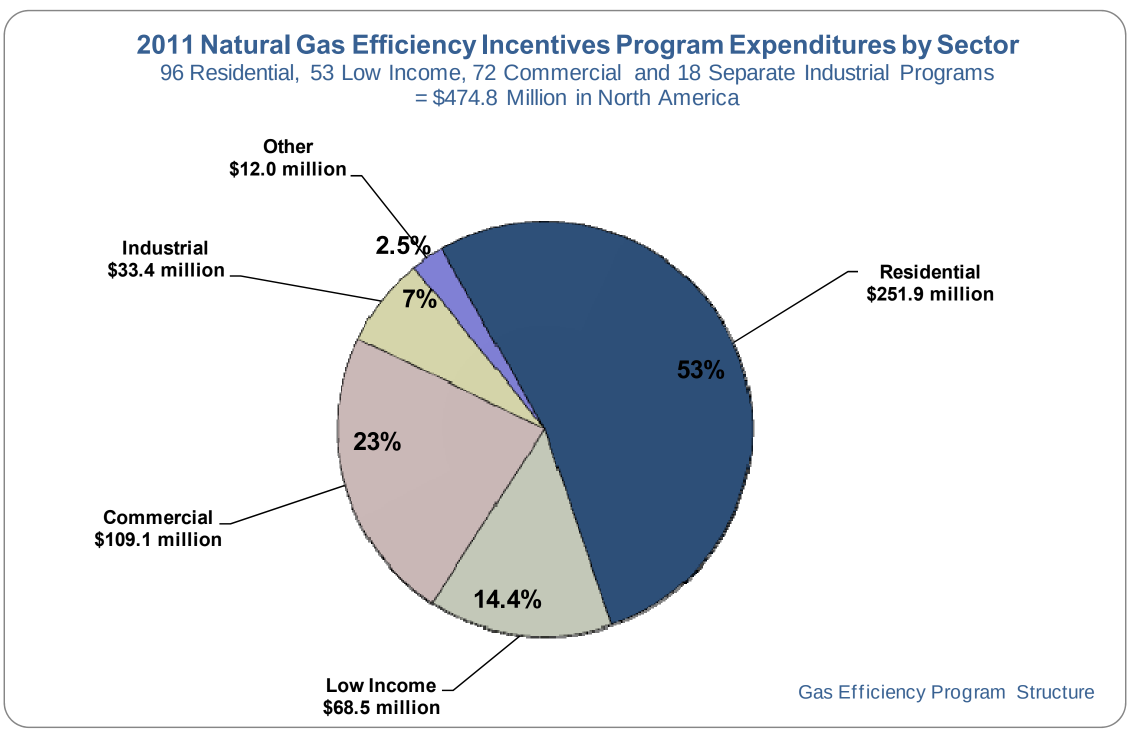
In the residential category, tiered efficiency incentives are offered in 64 percent of new whole house programs, 58 percent of furnace programs, 51 percent of boiler programs, and 46 percent of whole house retrofit and storage water heater programs. In the commercial segment, stepped up incentives are offered in 75 percent of furnace programs; 73 percent of boiler, new whole building and combined heat and power programs; and 68 percent of whole building retrofit programs. The next section (*Customer Incentives*), discusses further financial incentives and appliance rebates offered to customers to encourage efficiency improvements.

Customer Incentives

INCENTIVES FUNDING: Natural gas efficiency programs offer customers financial incentives to encourage energy conservation and improved efficiency. These include appliance rebates, equipment or project financing, and in many cases free measures to low income customers. Respondents reported 2011 expenditures for customer incentives and 2012 budgets.

Figure 3 shows the distribution of customer incentives funds in North America by market segment for the 2011 program year. As shown, residential programs were allotted more than 50 percent of incentive funds.

Figure 3



Spending reached $474.8 million on customer incentives in North America of which $251.9 million was allocated for residential incentives, $68.5 million for low income, $109.1 million for commercial, $33.4 million for industrial, and $12 million for other incentives. In the United States, $243.5 million in incentive funds were used for residential programs, $64.8 million for low income, $87.3 million for commercial, $21 million for industrial, and $10.6 million for other incentive programs—totaling to $427.2 million overall.

In North America, programs budgeted for the 2012 program year $307.9 million for residential programs, $96.6 million for low income, $154.1 million for commercial, $46.7 million for industrial, and $28 million for other incentives (a total of $633.3 million). United States 2011 incentive budgets total $582.4 million, of which $300.6 million are slated for residential programs, $86 million for low income, $131.1 million for commercial, $37.4 million for industrial, and $27.3 million for other programs.

A small portion of these incentives funds include trade ally incentives. The "other" category includes funds for outreach, education (e.g., school-based programs), training, and certification, multi-family (5-75 dwelling) programs, combined C&I, product development, and market transformation.

Some respondents were unable to separate industrial incentive dollars from commercial funds: about 10 percent of 2011 commercial expenditures and nine percent of 2012 commercial budgets include industrial dollars.

CASH REBATES AND OTHER FINANCIAL INCENTIVES: Program administrators use these incentive funds to provide customers with rebates on high-efficiency natural gas appliances, subsidize larger home or building efficiency projects, or finance energy-efficient purchases. Ninety percent of natural gas efficiency programs (104 of 115) offer customers in one or more segment cash rebates or other financial incentives for energy efficiency improvements. Residential customers are offered incentives in 97 percent of programs (101 of 104), low income customers in 38 percent (or 39 programs), commercial customers in 79 percent (82 programs), and industrial customers in 40 percent of programs. Twenty-percent percent (or 23 programs) offer financial incentives to all customer segments.

Across segments, incentive programs are most common for furnaces, boilers, storage water heaters, tankless water heaters, whole building retrofits, and programmable thermostats. In terms of dollar savings, generally customers benefit more when they opt for a whole system efficiency project, because they tend to find most generous incentives in a holistic approach and their energy bills will be significantly lowered in the long run.

As seen in Table 10, the incentive dollar amount varies widely depending on the type and number of measures and resulting energy savings. In low income programs, the rebates tend to cover more, if not all, of the costs of new high efficiency appliances. Higher incentives are also prevalent in custom commercial and industrial programs, commercial whole buildings (new and retrofits), energy management systems, and industrial gas cooling and combined heat and power (“other” category).

Table 10

DOLLAR RANGES FOR GAS EFFICIENCY REBATES & INCENTIVE PROGRAMS

EFFICIENCY MEASURES	RESIDENTIAL (101 Programs)			LOW INCOME (39 Programs)			COMMERCIAL (82 Programs)			SEPARATE INDUSTRIAL (42 Programs)		
	PROGRAMS	DOLLAR RANGE		PROGRAMS	DOLLAR RANGE		PROGRAMS	DOLLAR RANGE		PROGRAMS	DOLLAR RANGE	
Furnaces	93	$75	$2,000	33	$100	$4,500	71	$75	$25,000			
Boilers	75	$75	$2,600	28	$150	$4,500	75	$75	$25,000			
Dishwashers	9	$10	$100	4	$20	$25	16	$20	$2,000			
Clothes Washers	18	$25	$100	7	$35	$100	23	$50	$200			
Storage Water Heaters	77	$25	$900	27	$39	$1,400	69	$25	$25,000			
Tankless Water Heaters	64	$20	$900	22	$50	$800	56	$50	$25,000			
Whole Home/Building Retrofit	54	-	$50,000	34	$30	$5,486	29	-	$100,000			
New Whole Homes/Buildings	43	$200	$8,000	19	$100	$16,000	25	$150	$100,000			
Windows	23	$5	$600	10	$20	$4,000	20	$20	$2,500			
Programmable Thermostats	53	$10	$50	19	$20	$150	39	$20	$100,000			
Food Service Equipment							51	$15	$25,000			
Energy Mgmt. Systems							34	-	$100,000	6	-	$10,000
Custom Incentive Programs							45	-	$3,600,000	9	-	$3,600,000
Other	30	$5	$3,000	5	$100	$1,600	18	$35	$30,000	2	-	$500,000

Besides direct rebates, program administrators have developed various financial incentives to meet the needs of their market.   Table 11 shows examples of other types of incentive arrangements for residential efficiency improvements.

Table 11

OTHER FINANCIAL INCENTIVE ARRANGEMENTS IN RESIDENTIAL EFFICIENCY PROGRAMS	
Furnaces	• $200 - $400, Fuel Switch = $300 - $475 • 50 - 80% • 70% incremental cost of multi-family
Boilers	• 50 - 80% • 70% incremental cost of multi-family • Hydronic = $125 • Per Mbtu/Hr = $3/Mbtu
Clothes Washers	• 50 - 80%
Storage Water Heaters	• $50, Fuel switch = $100 • 50 - 80% • Natural Gas to Natural Gas = $400, Electric to Natural Gas = $550
Tankless Water Heaters	• $250, Fuel Switch = $450 • Natural Gas to Natural Gas = $550, Electric to Natural Gas = $675
Whole Home Retrofit	• Per Square Foot: $0.07 - $0.3 • 0% financing up to $10,000 • 30% to 100% of qualified cost • 50% of costs up to $275 • 50% up to $3,000 • 50% - 70% of cost to purchase/installation of cost-effective building shell measures • 50 - 80% • 70% of installed cost up to $500 • 70% of installed cost up to $600 • 70% of installed cost up to $750 • 75% up to $2,000 • Attic insulation = $0.25/sq ft, Wall insulation = $0.5/sq ft, Floor insulation = $0.5/sq ft • Cash incentive of 1/3 to 1/2 project cost plus interest financing • Insulation = $0.3/sq ft, Air sealing = $40/hour • Insulation = 70% of installed cost up to $500; Sealing = 70% of installed cost up to $200 • Site specific • Up to 90% • Varied average of and $750 in service per visit • Varies by measure up to $250
New Whole Home	• $250 plus access to other incentives (e.g., furnace) • Builder Incentive = $500-$1,000, Drain water heat recovery (DWHR) = $150 • Energy Star = $900 • Incremental cost • Site specific • Varies based on performance
Windows	• $0.95 per sq ft • $1 per sq ft • $10 per window; limit 50 • $2.25 per sq ft • $3 per sq ft • $3.00 per sq ft • Up to 70% of costs
Programmable T-Stats	• Free • Provide free or $25 if purchased by customer

Table 11 (continued) OTHER FINANCIAL INCENTIVE ARRANGEMENTS IN RESIDENTIAL EFFICIENCY PROGRAMS	
Other	• Boiler Reset • Clothes Dryer: $30 Clothes Dryer • Combination heating system/water heater: $1,000 - $1,600 • Direct vent space heat for residential • Drain water heat recovery: GFX, PowerPipe or equivalent • Dryers: $75, $100 - $150 • Duct and air sealing: $420 • Duct insulation: $200, $250 • Energy efficiency LivingWise® kits to select 6th grade classes to take home and use with parent(s) or guardians • Financing interest buy down: 0 - 2.99% • Financing: 0% ($2,500 - $10,000) and on-bill repayment option of Home Performance with Energy Star (HPWES) for qualified customers. • Fireplace • Floor and/or ceiling insulation: $0.3 per sq ft • Free flow showerheads/aerators • Gas space conditioning: $1,200 • High efficiency hearths • HVAC Quality Maintenance: $0 - $550 per system depending on measures selected • Indirect water heater: $300/unit • Integrated boiler/hot water unit: $300/unit • Multi-residence showerheads • NGV Fueling Unit: $2,000/unit • NGV Rebates: $1,000 - $3,000 • Opaque shell insulation and air sealing leakage: 30% of cost up to $3,000 • Pilotless hearth • Ranges: $100 - $200 • Residential Home Energy Reports, a behavioral change program by Opower • Smart Low-Flow Showerhead: $20 • Solar Water Heating Program has 3 categories with different rebate amounts • Space heaters • Weatherization kits: Free

As demonstrated in Table 11, 12 and 13, incentive reimbursements for residential and commercial/industrial programs may consist of a set dollar amount per high-efficiency appliance unit or involve a percentage of total equipment replacement or project cost (often capped at a specific dollar amount). Other programs pay a specific dollar amount per square footage or unit of energy saved. In some programs, the reimbursement is a percentage of the incremental cost of acquiring the higher efficiency product(s). In others, higher incentives are provided to larger volume customers that chose to upgrade to a higher efficiency level.

Other measures that qualify for rebates in residential programs are dryers, infrared heating, indirect water heaters, combined products such space heating system and water heater, integrated boiler and water heater units, water heater wrap, drain water heat recovery units tied to gas hot water heating systems air filter coupons, low-flow showerheads, heating system check service, hearth products (fireplaces, pilotless hearth, duct and air sealing, wall and attic insulation), LivingWise conservation and efficiency school education program and energy savings kits, free weatherization kits upon completed Energy Audit, and free thermostats.

In low income programs, incentives also cover combination space heat and water heater units and drain water heat recovery units. Several pay the full cost of high-efficiency measures, including appliance repairs and replacements. In other low-income programs, the utility pays up to 90 percent of the total installation costs, capped at a specific dollar limit. Still others include the full appliance replacement cost only if it can be justified by the energy savings, health and safety criteria or pass a Total Resource Cost test.

Table 12

Other Financial Incentive Arrangements in Low Income Efficiency Programs	
Furnaces	• 100% incremental cost for higher efficiency • 100% Measure + Implementation • Custom • Free • No cost • No cost if qualified for state heating system repair & replacement program • Up to cost effective limit • Up to full cost
Boilers	• 100% incremental cost for higher efficiency • 100% Measure + Implementation • Custom • No cost • No cost if qualified for state heating system repair & replacement program • Up to cost effective limit • Up to full cost
Dishwashers	• 100% Measure + Implementation
Clothes Washers	• 100% Measure + Implementation • Up to cost effective limit
Storage Water Heaters	• 100% Measure + Implementation • Custom • Free • No cost • Up to cost effective limit
Tankless Water Heaters	• 100% Measure + Implementation • Custom • Free • No cost • Up to cost effective limit
Whole Home Retrofit	• $0.26 - $0.6 per sq ft installed or conditioned living space • $2,500 or less • $30 - $5,486 per measure depending on deemed savings per Sq. Ft. and energy audit modeling software results • 30% to 100% of qualified cost • 50% of measure cost • 70% of installed cost up to $500 • 70% of installed cost up to $750 • 90% of the job cost (not to exceed $3500) for projects where the modeled savings to investment ration (SIR) is 1.0 or better • 100% Measure + Implementation • Direct install • Free • Insulation: 70% of installed cost up to $500, Sealing: 70% of installed cost up to $200 • No limit, but average watched • No limit; Average approximately $3,000 • Site specific • Up to cost effective limit • Up to full cost • Varies
New Whole Home	• 100% Measure + Implementation • Direct install • Site specific • Up to cost effective limit • Usually custom • Varies • Water Heater = $100, Programmable thermostat = $100, DWHR = $300, Furnace = $100

Table 12 (continued) OTHER FINANCIAL INCENTIVE ARRANGEMENTS IN LOW INCOME EFFICIENCY PROGRAMS	
Windows	• $2.25 per sq ft • 100% Measure + Implementation • Total cost • Up to cost effective limit
Programmable T-Stats	• $30 copay • 100% Measure + Implementation • No cost
Other	• Combination heating system/water heater: $1,000 - $1,600 • Drain water heat recovery: $200 • Dryers: $100 - $150 • Gas space conditioning: $1,200 • Range: Free • Ranges: $100 - $200

Other measures that qualify for rebates in C&I programs include continuous modulating burners, modulating boiler controls, reset control, low-flow sprayer, ECM motors, refrigerators, aerators, low-flow showerheads, gas furnace and boiler tune-ups, vent damper, primary air dampers, steam trap service, free spray valves, insulation (roof, wall, floor), opaque shell insulation and air sealing leakage, multi-family residential showerhead program, drain water heat recovery units tied to gas hot water heating systems, dryers, integrated condensing boiler and water heater, gas cooling, combined heat and power, infrared heat, and solar heating. Many of the C&I programs are custom-analysis based, and financial incentives are awarded on a site-specific basis. Table 13 shows examples of other types of incentives arrangements for C&I efficiency improvements.

Table 13

OTHER FINANCIAL INCENTIVE ARRANGEMENTS IN COMMERCIAL/INDUSTRIAL EFFICIENCY PROGRAMS	
Furnaces	• $150/unit <= 200 Mbtu/Hr • $200 - $400, Fuel switch $300 - $475 • $3/Kbtu/hr • $400 - $800 or incentive up to $100,000. If annualized therm usage is <40,000 maximum incentive is $50,000. • 70% incremental cost of multi-family • Prescriptive value based on size vs. incremental cost vs. energy caps • Up to 50% of cost • Up to 50% of the incremental cost
Boilers	• $500 - $15,000 or incentive up to $100,000. If annualized therm usage is <40,000 maximum incentive is $50,000. • 14% Cost systems > 75 KBtu, 82% - 86% TE, 20% Cost systems > 75 Kbtu, 87% - 100% TE, 20% Cost Solar Thermal with gas backup • 25% of purchase price up to $5,000 • 70% incremental cost of multi-family • Per Btu/Hr: $4, • Combo Systems $4 per Btu/Hr • Per Kbtu/hr: $2 or $3, $2 - $3.25 • Per MBtu/Hr: $1 - $1.5, $1 - $ 2, $2 • Per MMBtu input: $4 to $8, $1,400 - $2,000 • Per MMBtu: $1,400 - $4,000 • Per sq ft: $2 - $3.25 • Prescriptive value based on size vs. incremental cost vs. energy caps • Up to 50% • Up to 50% of the incremental cost
Dishwashers	• Custom • Site-Specific & Unique to Customer

Table 13 (continued) **OTHER FINANCIAL INCENTIVE ARRANGEMENTS IN COMMERCIAL/INDUSTRIAL EFFICIENCY PROGRAMS**	
Clothes Washers	• Custom in multi-family • Prescriptive value based on size • Site-Specific & Unique to Customer • Up to 50% of the incremental cost
Storage Water Heaters	• Per kBtu: $2 • Per Mbtu: $2.00 • Per Kbtu/Hr: $2.5 • $50 - $500 or incentive up to $100,000. If annualized therm usage is <40,000 maximum incentive is $50,000. • $50 or $2 per Kbtu/hr • $50, Fuel switch $100 • 30-80% • 50% up to $1,100 • Custom • Up to 50% • Up to 50% of the incremental cost
Tankless Water Heaters	• $1.5 to $2.5 Kbtu Hr In • $2 per kBtu $2 per Kbtu/hr • $250, Fuel switch $450 • $30 - $40/GPM • $500 - $800 or incentive up to $100,000. If annualized therm usage is <40,000 maximum incentive is $50,000. • Custom • Up to 50% • Up to 50% of the incremental cost
Whole Building Retrofit	• 50% up to $100,000. If annualized therm usage is <40,000 maximum incentive is $50,000. • 70% of installed costs up to $5,000; Sealing = 70% of installed cost up to $1,500 • Custom, based upon measure • Per Dth: $5/Dth, $7/Dth • Per sq ft: $0.03 - $0.04, $0.04 - $0.12 • Specific and unique to customer • Up to 50% • Up to 50% of the incremental cost
New Whole Building	• 50% up to $100,000. If annualized therm usage is <40,000 maximum incentive is $50,000. • Building projects repaid on a $ per kWh and $ per Therm based on the actual energy savings achieved by the building as compared to code. The $ per kWh or Therm is based on a sliding scale based on the percentage of savings above code. • C&I building projects paid on a $ per kWh and $ per Therm based on actual energy savings achieved by the building as compared to code. The $ per kWh or Therm is based on a sliding scale based on the percentage of savings above code. • Custom, based upon measure • Dollar amount varies based on performance • Incremental cost • Per Dth: $5/Dth, $7/Dth • Per kWh or Therm: $0.09/kWh or $1.00/Therm savings up to 50% of the project cost • Site-Specific & Unique to Customer • Up to $2 per sq ft • Up to 50% of the incremental cost
Windows	• Per sq ft: $0.28; $1 up to $2,500 sq ft limit • Per kWh or KW or Therm: $0.09/kWh, $100/kW and $1.00/Therm based on calculated annual savings up to 50% of the project cost • Site-Specific & Unique to Customer • Up to 50% • Up to 50% of the incremental cost
Programmable T-Stats	• $25 or incentives up to $100,000. If annualized therm usage is <40,000 maximum incentive is $50,000. • Considered in controls upgrade • Site-Specific & Unique to Customer • Up to 40% of project cost • Up to 50% • Up to 50% of the incremental cost

Table 13 (continued) OTHER FINANCIAL INCENTIVE ARRANGEMENTS IN COMMERCIAL/INDUSTRIAL EFFICIENCY PROGRAMS	
Food Service Equipment	• 80% • Prescriptive • Site-Specific & Unique to Customer • Up to 50%
Energy Mgmt. Systems	• 30-80% • 50% of retrofit, 75% of new construction • 50% up to $100,000. If annualized therm usage is <40,000 maximum incentive is $50,000. • Custom, depends on measure • Incentives determined at 150% of customer's first-year energy dollar savings • Per Dth: $7/Dth • Per kWh, KW, or Therm: $0.09/kWh, $100/kW and $1.00 / therm based on calculated annual savings up to 50% of the project cost • Rebated through custom program • Site-Specific & Unique to Customer • Up to 40% of project cost • Up to 50% • Up to 50% of the incremental cost • Varies based on performance
Custom Incentive Programs	• 30% of the project's total cost up to a maximum of $25,000. Project energy costs >= 7,500 Therm - $1/Therm. Project energy costs =< 7500 Therm - $0.75/Therm. • 50% of retrofit, 75% of new construction • 50% up to $100,000. If annualized therm usage is <40,000 maximum incentive is $50,000. • Based on savings • Incentives determined at 150% of customer's first-year energy dollar savings • Less of 50% of project cost or $/Saved Dth • Offered incremental incentive for Combined Heat and Power to match statewide program incentive up to $1,000,000 • Per Dth: $7/Dth • Per Mcf: 4/Mcf or $40% of project cost whichever is less; $10 saved up to 50% of cost; • Per sq ft: $0.28 - $0.37 • Per Therm: $0.8/Therm; $1/Therm • Site-Specific & Unique to Customer • Up to $25,000 • Up to 40% of project cost • Up to 50% • Up to 50% of the incremental cost
Other	• All programs: 8-10 cents/M3 • Boiler Controls: $250. After market boiler reset controls: $225. • Condensing unit heaters and low intensity infrared heaters • Continuous modulating burners = 25% of equipment cost or $15,000, Boiler tune-ups = $500-$750, Steam traps = 50% of equipment cost or $2,500, Vent damper = 50% of equipment cost or $500, Primary air damper = 50% equipment or $500. Steam traps repairs. • Conversion: $75 per 100,000 Btu • Dryer: $75 • Financing Interest buy down = 7%-9% • Food Service: $200 Infrared griddles, $400 infrared fryers, $400 convection ovens, $400 conveyor ovens, $500 booster heaters • Gas space conditioning: $50/Ton • HVAC Quality Maintenance $75 - $1,500 depending on measures selected • Hydronic boiler: $125 • Indirect water Heater $300/unit • Infrared heaters: $2 per 1,000 Btu/hr • Integrated Boiler/Hot water unit $300/unit. Integrated condensing boiler/water heater: $1,000 - $1,600. • NGV Fueling Unit: $2,000/unit; NGV Rebates: $1,000 - $3,000 • Pre-Rinse Spray Valve: $35 • Roof, wall & floor insulation: 20% of installed cost up to $10,000; spray valves are free • Solar Water Heating Program, which has 3 categories with different rebate amounts.
SEPARATE INDUSTRIAL PROGRAM	• Custom Incentive Program: Up to 50%, $1 per Therm, 8-10 cents per M3, Based on savings • Energy Management Systems: $0.09 per kWh, $100/KW, $1 per Therm based on calculated annual savings up to 50% of the project cost, Up to 50% • Other: Gas cooling up to $150,000. Combined Heat and Power up to $500,000.

COST EFFECTIVENESS OF INCENTIVES PROGRAMS: Respondents were asked whether they assessed the cost effectiveness of each incentive program, which tests they used, and whether each program was found to be cost effective. Table 14 shows the number and percentage of programs that used a cost test generally and the number and percentage of programs that that passed cost effectiveness overall.

According to the survey sample, 100 percent of the following programs were found to be cost effective for all measures: windows, programmable thermostats, food service equipment, and energy management systems, and custom incentive programs. This is followed by furnace programs (which are found to be cost effective in 99 percent of the survey sample, or 71 of 72 programs) and new whole home/building programs (98 percent, or 39 of 40 programs). Ninety-seven percent of boiler and 95 percent of clothes washer programs passed the cost test, followed by storage water heaters (94 percent), dishwasher and whole home/building retrofits (93 percent), and tankless water heater programs (which passed the cost test in 90 percent of cases).

Table 14

CUSTOMER INCENTIVE PROGRAMS AND COST EFFECTIVENESS					
EE MEASURE	PROGRAMS THAT USED A COST TEST	PERCENTAGE COST-TESTED	REPORTED TEST RESULTS	PASSED C.E. TEST	PERCENTAGE THAT PASSED
Furnaces (96 Programs)	78	81%	72	71	99%
Boilers (84 Programs)	71	85%	66	64	97%
Dishwashers (18 Programs)	16	89%	15	14	93%
Clothes Washers (28 Programs)	25	89%	22	21	95%
Storage Water Heaters (87 Programs)	73	84%	65	61	94%
Tankless Water Heaters (72 Programs)	58	81%	52	47	90%
Whole Home/Building Retrofits (61 Programs)	50	82%	44	41	93%
New Whole Home/Whole Building (48 Programs)	42	88%	40	39	98%
Windows (30 Programs)	27	90%	21	21	100%
Programmable Thermostats (62 Programs)	52	84%	48	48	100%
Food Service Equipment (51 Programs)	44	86%	39	39	100%
Energy Management Systems (32 Programs)	27	84%	25	25	100%
Custom Incentive Programs (46 Programs)	42	91%	37	37	100%
Other Products (31 Programs)	19	61%	18	17	94%

Table 15, on the next page, provides more details regarding the specific cost test used per product or incentive program. The tests are categorized as participant cost test (PCT), ratepayer impact measure (RIM), societal cost test (SCT), total resource cost (TRC), utility cost test (UCT), multi-test, or other. Table 15 also shows the number and percentage of programs that passed each of these tests. Many programs used multiple tests, while others used all five. Respondents were asked about the cost effectiveness of each incentive program overall and not by customer segment, recognizing that the cost-effectiveness of a specific incentive program may vary by customer segment. A brief description of the five common tests can be found on page 43.

Across efficiency measures, the total resource cost test was the most commonly employed, ranging from 31 percent (for dishwasher programs) to 57 percent (food service equipment programs). On the other hand, the participant cost test and ratepayer impact tests were not used on their own in any program. Also the societal cost test and utility cost tests are equally used on their own; however, much less than the total resource cost test as already mentioned.

Table 15

COST EFFECTIVENESS TESTS USED PER GAS EFFICIENCY INCENTIVE PROGRAM AND RESULT PER TEST
(NUMBER OF PROGRAMS & PERCENTAGE)

EE MEASURE	TALLY TYPE	Specific Test Administered								Passed Specific Test							
		PCT	RIM	SCT	TRC	UCT	MULTI	OTHER	ALL	PCT	RIM	SCT	TRC	UCT	MULTI	OTHER	ALL
FURNACE 78 PROGRAMS	#	0	0	5	40	6	19	3	3	0	0	5	37	4	18	3	3
	%	0%	0%	6%	51%	8%	24%	4%	4%	n/a	n/a	100%	93%	67%	95%	100%	100%
BOILER 71 PROGRAMS	#	0	0	5	39	6	14	3	3	0	0	5	36	4	12	3	3
	%	0%	0%	7%	55%	8%	20%	4%	4%	n/a	n/a	100%	92%	67%	86%	100%	100%
DISHWASHER 16 PROGRAMS	#	0	0	0	5	4	4	1	1	0	0	0	4	3	4	1	1
	%	0%	0%	0%	31%	25%	25%	6%	6%	n/a	n/a	n/a	80%	75%	100%	n/a	100%
CLOTHES WASHERS 25 PROGRAMS	#	0	0	2	7	6	7	1	1	0	0	2	6	4	6	1	1
	%	0%	0%	8%	28%	24%	28%	4%	4%	n/a	0%	100%	86%	67%	86%	100%	100%
STORAGE WATER HEATER 73 PROGRAMS	#	0	0	4	38	7	16	3	3	0	0	4	30	5	14	3	3
	%	0%	0%	5%	52%	10%	22%	4%	4%	n/a	n/a	100%	79%	71%	88%	100%	100%
TANKLESS WATER HEATER 58 PROGRAMS	#	0	0	2	28	6	15	3	2	0	0	2	21	4	13	3	2
	%	0%	0%	3%	48%	10%	26%	5%	3%	n/a	0%	100%	75%	67%	87%	100%	100%
WHOLE HOME OR BLDG. RETROFITS 50 PROGRAMS	#	0	0	3	25	6	12	1	1	0	0	2	19	4	12	1	1
	%	0%	0%	6%	50%	12%	24%	2%	2%	n/a	n/a	67%	76%	67%	100%	100%	100%
NEW WHOLE HOME/BLDG. 42 PROGRAMS	#	0	0	2	22	5	8	0	3	0	0	2	19	5	8	0	3
	%	0%	0%	5%	52%	12%	19%	0%	7%	0%	n/a	100%	86%	100%	100%	n/a	100%
WINDOWS 27 PROGRAMS	#	0	0	0	11	6	7	0	2	0	0	0	8	4	6	0	2
	%	0%	0%	0%	41%	22%	26%	0%	7%	n/a	n/a	n/a	73%	67%	86%		100%
PROGRAMMABLE THERMOSTAT 52 PROGRAMS	#	0	0	5	28	4	8	3	2	0	0	5	27	2	8	3	2
	%	0%	0%	10%	54%	8%	15%	6%	4%	n/a	n/a	100%	96%	50%	100%	100%	100%
FOOD SERVICE EQUIPMENT 44 PROGRAMS	#	0	0	4	25	4	7	2	1	0	0	4	22	3	7	2	1
	%	0%	0%	9%	57%	9%	16%	5%	2%	n/a	n/a	100%	88%	75%	100%	100%	100%
ENERGY MGMT. SYSTEM 27 PROGRAMS	#	0	0	3	13	4	5	0	2	0	0	3	12	3	5	0	2
	%	0%	0%	11%	48%	15%	19%	0%	7%	n/a	0%	100%	92%	75%	100%	n/a	100%
CUSTOM INCENTIVE PROG. 42 PROGRAMS	#	0	0	5	18	6	9	2	2	0	0	5	16	4	8	2	2
	%	0%	0%	12%	43%	14%	21%	5%	5%	n/a	n/a	100%	89%	67%	89%	100%	100%
OTHER 19 PROGRAMS	#	0	0	1	8	1	7	1	1	0	0	1	7	1	6	1	1
	%	0%	0%	5%	42%	5%	37%	5%	5%	n/a	n/a	100%	88%	100%	86%	100%	100%

While all the efficiency incentive programs passed the PCT, RIM, SCT and UCT tests, the more instructive survey answers relate to the TRC test. According to responses regarding the TRC, programs passed the TRC as follows: programmable setback thermostats (27 of 28, or 96 percent of programs), furnaces (37 of 40, or 93 percent), boilers (36 of 39, or 92 percent), energy management systems (12 of 13, or 92 percent), and custom incentive programs (16 of 18 or 89 percent).

Efficiency Loans

As an alternative approach to reducing up-front costs, a number of efficiency programs provide customers with the option of financing their energy efficiency upgrades. Thirty percent (34 of 115 programs) provide customers access to loans, and of those 97 percent (or 33 programs) offer financing in conjunction with other incentives (e.g., equipment rebates). Twenty-nine of the 34 programs have residential energy efficiency loan programs, 17 have commercial, and 13 have industrial loan programs (see Table 16). Of these, eight offer loans to all customer segments.

Table 16

Natural Gas Efficiency Financing Programs 24 Programs					
Segment	Programs	Loan Type	Program Percentage	Loan Administrator	Program Percentage
Residential	29	Interest-Free	32%	In-House	32%
Commercial	17	Interest Rate Buy-Down	47%	Third-party	62%
Industrial	13	Both	9%	Both	3%
		Other	12%		

Programs may offer interest-free loans, interest rate reduction programs, loans with interest, or simply access to loans by a third party. Of the 34 programs, 11 (or 32 percent) have interest-free loans, 16 (or 47 percent) offer to buy down the interest on the loan, and three (or 9 percent) include both types of financing. Another 12 percent (four programs) have other financing arrangements, such as zero percent APR on-bill repayment and 10-year interest free financing for comprehensive whole performance projects.

Several ratepayer-funded energy efficiency financing programs integrate loan repayment into the customer's monthly utility bill as a monthly installment repayment plan. Such "on-bill financing" (or "pay-as-you-save") arrangements exist in 32 percent of programs (or 15 of 47 programs). Of these, seven offer on-bill financing to residential customers, three to commercial customers, and five to both segments.

Thirty-two percent of loan programs (11 of 33) are administered in house, while 62 percent (or 21 programs) are processed by a third party. In one case, the loan program is administered jointly in-house and by a third-party.

Internal Tracking Systems

When asked whether they used an internal system to track natural gas efficiency programs, 90 of 113 respondents (or 80 percent) indicated that they did. Of these, 62 percent developed their tracking system in house, 10 percent used a specialized off-the-shelf tracking package, and 26 percent had their tracking software customized by a vendor. Another two percent used a combination of in-house and vendor-customized systems (see Table 17).

Table 17

Internal Program Tracking Systems 93 Programs		
	Programs	Percent
Developed In-House	58	62%
Specialized Off-the-Shelf	9	10%
Customized by Vendor	24	26%
Both In-House & Vendor-Customized	2	2%

Some use Excel spreadsheets for their in-house applications, while others are developing a web-based database. Most program administrators track program budgets, expenditures, energy savings (EM&V results), and the number of participants and/or processed rebates per program. Cost and savings data are often broken down per measure and customer. Many track gross impacts, while others quantify free ridership, spillover, peak winter and summer factor, water savings, and sewer savings. Some keep track of expenditures (including incentives) against budgets and of therm savings against goals, by program and portfolio. Others document cost-effectiveness metrics, including benefit cost ratios or SIR, and avoided costs.

Tracking systems may include energy demand, demographic and weather normalized data. Many maintain information at several levels: utility, project, program, customer, and/or measure level. Some organize data by proposed and completed projects. Project information may include cost, contractor and vendor information, residential retrofit screenings or audits, equipment quantity, models and age, measure efficiency, and overall project savings.

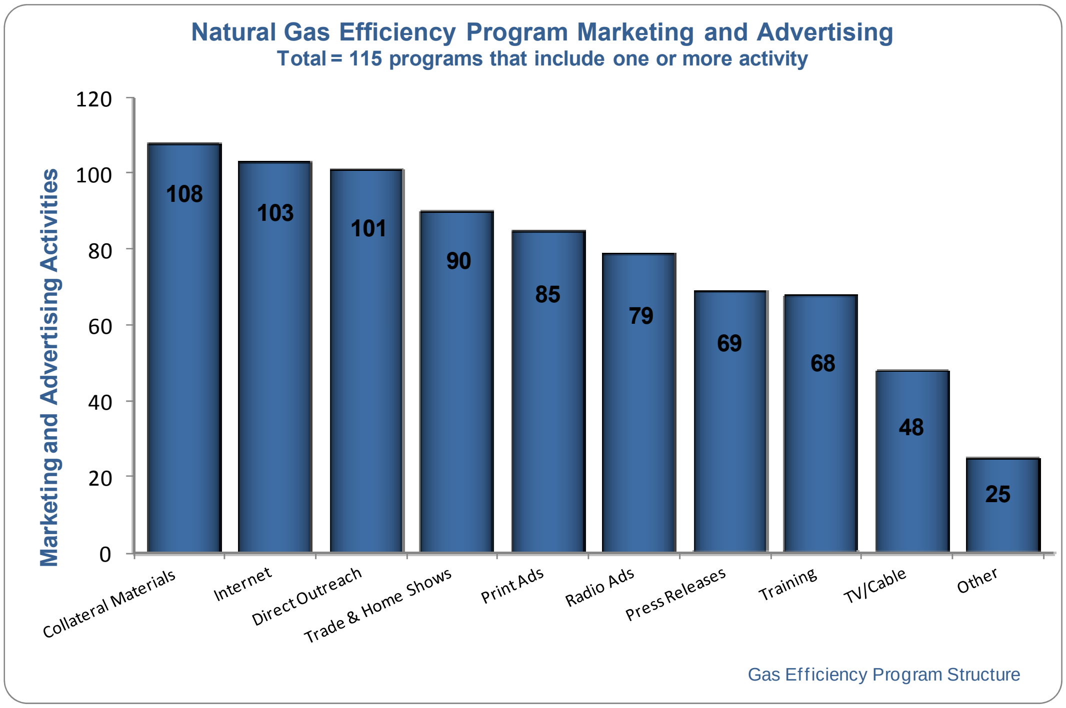
Customer account data may include name and address, customer rate class, meter numbers, years connected, how they learned about program, type of dwelling or facility, including year built and square footage, owned appliances, rebates processed, financing offers, date of installation and of rebate check, new equipment AFUE, old appliance AFUE, equipment cost, useful life of improvement, pre and post energy usage, and pre and post billing.

Program and measure metrics may include type, model number, quantity installed, cost, deemed and projected savings, and annual and lifetime savings.

Efficiency Program Marketing

Natural gas efficiency programs are promoted via an array of marketing efforts in the form of collateral materials, internet tools, direct outreach, trade and home show promotions, training, print ads, press releases, radio commercials and/or TV and cable advertisements. Ninety-seven percent of programs (111 of 115) use a number of these efficiency marketing approaches. Twenty-five of these programs employ all outreach tools. As seen in Figure 4, most widely adopted as a promotional approach are collateral materials, such as brochures and bill inserts (94 percent of programs), internet tools (90 percent), and direct contact (88 percent).

Figure 4



Respondents were asked to identify which of two audiences (end users and/or trade allies) they sought to reach with each marketing approach, realizing that it is more difficult to identify or segregate a target audience via internet tools, print ads, and trade shows. As shown in Table 18 on the next page, in all marketing categories, a greater percentage of programs directed their efforts toward end users than those targeting trade allies. One exception is with training programs: 41 percent of respondents geared their training programs toward end users, while 81 percent targeted trade allies for such training programs (alone or with end users).

While recognizing that the success of each approach varies per target market and that success rankings tend to be subjective, we asked respondents to rank the success of each combined effort, where a rating of 1 signifies “most successful” and 10 indicates “least successful.” Table 18 shows the number of respondents that rated each approach per target audience, the average success ranking of each approach, and the percentage of rankings that fall within one of three success ranges (high, medium and low). The marketing tools are ordered according to success ranking, starting with the most successful according to survey responses.

For end users, direct outreach and collateral materials were ranked highest, followed by TV/cable and print ads. With respect to trade allies, respondents ranked TV cable ads, direct outreach, collateral materials and training the highest among outreach methods.

Other marketing approaches include contractor/vendor promotions, elementary school conservation education outreach (indirect outreach to parents), social media, sponsorship of collegiate sports and professional basketball teams, billboards, workshops, truck wraps, giveaways, full newspaper articles covering programs, energy fairs, and trade/industry association memberships and sponsorships. Other examples include TV coverage of energy efficiency events, a local cable community TV program, and direct mail to area HVAC contractors with email updates regarding programs. Also cited as very successful were outreach to local real estate offices and to various community groups (including environmental commissions, green fairs and rotaries).

Table 18

SUCCESS OF MARKETING APPROACHES AND TARGET AUDIENCE								
MARKETING TO END USERS								
Marketing Approach	**Programs Using this Tool**	**Programs Targeting End Users**		**Success Ratings**				
		Number of Programs	**Percentage**	**Number of Ratings**	**Average Success Ranking**	**High Ranking 1 ≤> 4**	**Mid Ranking 4 ≤≥ 6**	**Low Ranking > 6**
Collateral Materials	108	104	96%	81	4.5	44%	27%	28%
TV/Cable	48	43	90%	33	4.6	30%	42%	27%
Print Ads	85	84	99%	60	4.7	28%	52%	20%
Direct Outreach	101	87	86%	66	4.7	38%	29%	33%
Training	68	28	41%	22	4.9	32%	41%	27%
Trade & Home Shows	90	83	92%	58	5.1	31%	38%	31%
Radio Ads	79	76	96%	52	5.2	23%	56%	21%
Internet	103	95	92%	74	5.2	20%	50%	30%
Press Releases	69	64	93%	44	5.2	27%	39%	34%
Other	25	23	92%	16	5.6	25%	44%	31%
MARKETING TO TRADE ALLIES								
Marketing Approach	**Programs Using this Tool**	**Programs Targeting Trade Allies**		**Success Ratings**				
		Number of Programs	**Percentage**	**Number of Ratings**	**Average Success Ranking**	**High Ranking 1 ≤> 4**	**Mid Ranking 4 ≤≥ 6**	**Low Ranking > 6**
TV/Cable	48	10	21%	7	3.9	43%	43%	14%
Direct Outreach	103	70	68%	58	4.3	50%	14%	36%
Collateral Materials	108	48	44%	36	4.8	31%	53%	17%
Training	68	57	84%	43	4.9	47%	14%	40%
Trade & Home Shows	69	56	81%	43	5.0	28%	49%	23%
Other	25	4	16%	2	5.0	50%	0%	50%
Print Ads	85	37	44%	29	5.2	21%	52%	28%
Radio Ads	79	20	25%	15	5.3	27%	40%	33%
Internet	101	53	52%	38	5.4	26%	37%	37%
Press Releases	90	31	34%	23	6.5	4%	48%	48%

In terms of funding for efficiency marketing, 89 percent of respondents (87 of 98) indicated they have a set budget specifically for promotional activities. They also relayed what percentage of their overall efficiency program budget was spent on advertising or marketing. Based on these responses, programs spent between 0.6 percent and 60 percent of natural gas efficiency program dollars on advertising/marketing. The median spending was five percent of total efficiency program funds.

Table 19 breaks down program promotional spending into ranges as a percentage of total program dollars. As shown, 91 percent of programs (84 of 92) spent more than five percent of their efficiency program budget on marketing and outreach; however, only seven percent used more than 25 percent of their overall efficiency program dollars for marketing.

Table 19

Marketing Funds as a Percentage of Overall Natural Gas Efficiency Program Budget 92 Programs	
Percentage Range of Program Budget	**Number of Programs**
1% or less	**8**
1% > ≤ 5%	**45**
5% > ≤ 10%	**21**
10% > ≤ 25%	**12**
25% > ≤ 50%	**5**
Greater than 50%	**1**

Other Programs: Codes & Standards and Emerging Technology Demonstrations

Nine percent of respondents (10 of 109) indicated that their natural gas efficiency program includes a regulator-approved ratepayer-funded codes and standards advocacy program, which promotes improvements to building efficiency codes and to appliance standards. This is achieved through studies, drafting guidelines, research, expert testimony, stakeholder meetings, marketing, and compliance improvement activities.

Some accomplish this by funding the codes and standards advocacy efforts within a statewide program. Others engage third-party vendors to provide regular training for codes compliance, or they fund energy efficiency continuing education credits for residential and commercial builders and contractors. Others work with dealers and contractors to encourage the use of high efficiency appliances (e.g., tank style water heaters with the highest energy factor ratings). Still others promote above code construction practices in their new construction efficiency programs.

Ten percent of respondents (11 of 111) indicated that their natural gas efficiency program includes pre-commercial demonstrations of emerging technologies. Of the 11, two stated that their public utility commission requires such demonstrations.

II. Natural Gas Efficiency Program Funding and Impacts

This section describes utility funding for natural gas efficiency programs in the U.S. and Canada and the resulting annual energy saving impacts. Program year 2011 expenditures correspond to funding by 132 utilities for programs administered either by the utility or by a third party, such as a nonprofit public benefit organization or a state agency that runs a statewide program. Budgets for 2012 represent planned funding for 130 programs. Budget data were collected during spring and summer 2012; therefore, any budgetary changes made after this period—due to newly approved programs or funding cuts—are not reflected in this report. Some dollars reported for 2011 represent carryover of unspent funds from 2010.

Respondents were asked to break down 2011 expenditures and 2012 budgets by customer class or segment. Where data were not available by segment, a slight percentage of respondents reported overall spending amounts in the "Other" category. Also where respondents were unable to break down spending for specific activities (such as evaluation, measurement and verification) by customer segment, they placed these dollar amounts under "Other." Also some respondents were not able to separate low-income program dollars from residential program funds (either overall or for specific activities, such as education and online resources), and a small number of commercial program dollars were combined with residential program funds.

All natural gas efficiency program dollars discussed in this report are sourced from ratepayers. Some efficiency program funds originate from other sources, such as utility shareholders and American Recovery and Reinvestment Act (ARRA) dollars. A small number of survey respondents did receive stimulus dollars and other non-ratepayer funds for efficiency programming, all of which have been excluded from this report. The scale of these non-ratepayer funds is very small compared to the ratepayer program dollars reported in this study: stimulus dollars amount to 0.2 percent of the total 2011 U.S. efficiency expenditures reported below, and other non-ratepayer funding represent 0.03 percent of 2011 U.S. program spending. Given that the reporting methodology varies among respondents, expenditure and budget data should be regarded as estimates rather than exact figures.

Natural Gas Efficiency Program Expenditures and Funding

In the United States, utilities spent $958 million in 2011 on natural gas efficiency programs. Also they have budgeted nearly $1.4 billion for the 2012 program. Program expenditures reached $1.1 billion in North America (U.S. and Canada) in 2011. Cumulative North American program budgets are expected to approach $1.5 billion in 2012 (see Table 20). Appendix B and C present a breakdown of 2011 expenditures and 2012 budgets by state and region.

Table 20

NATURAL GAS EFFICIENCY PROGRAM EXPENDITURES AND BUDGETS BY CUSTOMER CLASS[1]

	2011 EXPENDITURES ($ MILLION)[2] 132 PROGRAMS			2012 BUDGETS ($ MILLION) 130 PROGRAMS[3]		
CUSTOMER SEGMENT	**U.S.**	**CANADA[4]**	**N. AMERICA**	**U.S.**	**CANADA**	**N. AMERICA**
Residential	$433.6	$14.8	$448.4	$546.2	$18.4	$564.6
Low-Income	$208.5	$12.4	$220.9	$285.4	$18.1	$303.5
Commercial[5]	$174.6	$32.6	$207.2	$293.0	$39.9	$333.0
Industrial	$50.4	$14.8	$65.2	$69.8	$13.0	$82.8
Other	$75.0	$27.6	$102.6	$170.9	$26.9	$197.9
EM&V[6]	$15.5	$1.4	$16.9	$34.5	$1.7	$36.2
TOTAL[7]	**$957.6**	**$103.6**	**$1,061.2**	**$1,399.9**	**$118.1**	**$1,518.0**

[1] While most program budgets coincide with the calendar year, 23 percent do not, and thus their program year begins in one calendar year and ends during the next.

[2] Some 2011 funds represent unspent dollars carried over from the 2009 program year. Carryover funds are not included in 2012 budgets. Not all reported 2011 expenditures represent a full year, because a number of programs were launched after January 1, 2011.

[3] About 7 percent of 2012 budgets had not been approved at the time the data were submitted to AGA, or only the half of the year had been approved while the balance remained under the projected status.

[4] All currency is reported in U.S. dollars. This report uses the July 11, 2011 Bloomberg exchange rate of 0.9643 USD = 1 CAD.

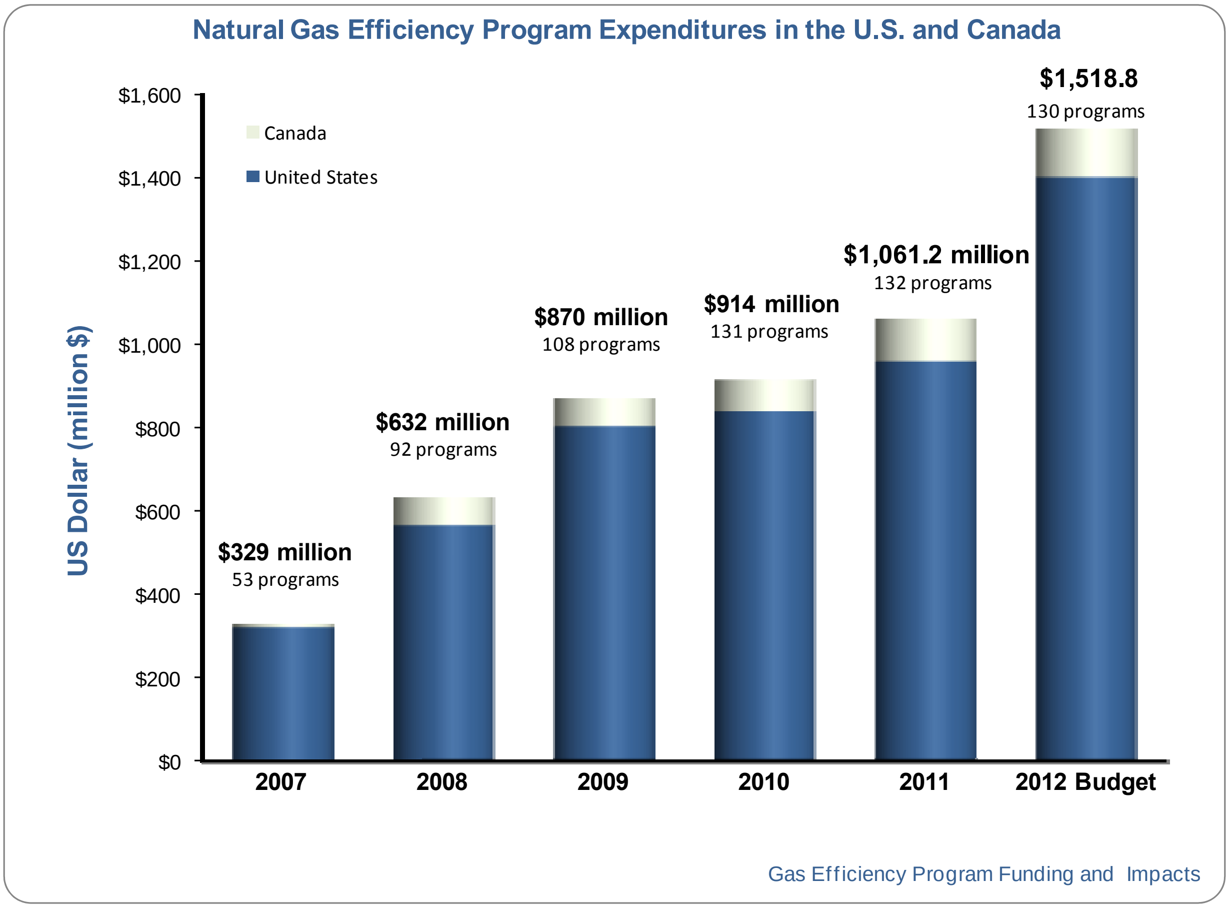
[5] A small percentage of commercial funds represent combined C&I dollars as follows: about 6 percent of 2011 commercial expenditures in the U.S. and 5 percent in North America, and about 8 percent of 2012 commercial budgets in the U.S. and 7 percent in North America include industrial funds.

[6] Less than 1 percent of funds across segments represent EM&V funds not included in the EM&V category.

[7] Subcategories might not add up exactly to reported totals due to rounding.

Figure 5 presents natural gas efficiency program funds from 2007 through 2012. This comparison is intended for illustrative purposes, since spending growth cannot be entirely attributed to new and expanded programs but also to differences in survey samples from one year to the next.

Figure 5

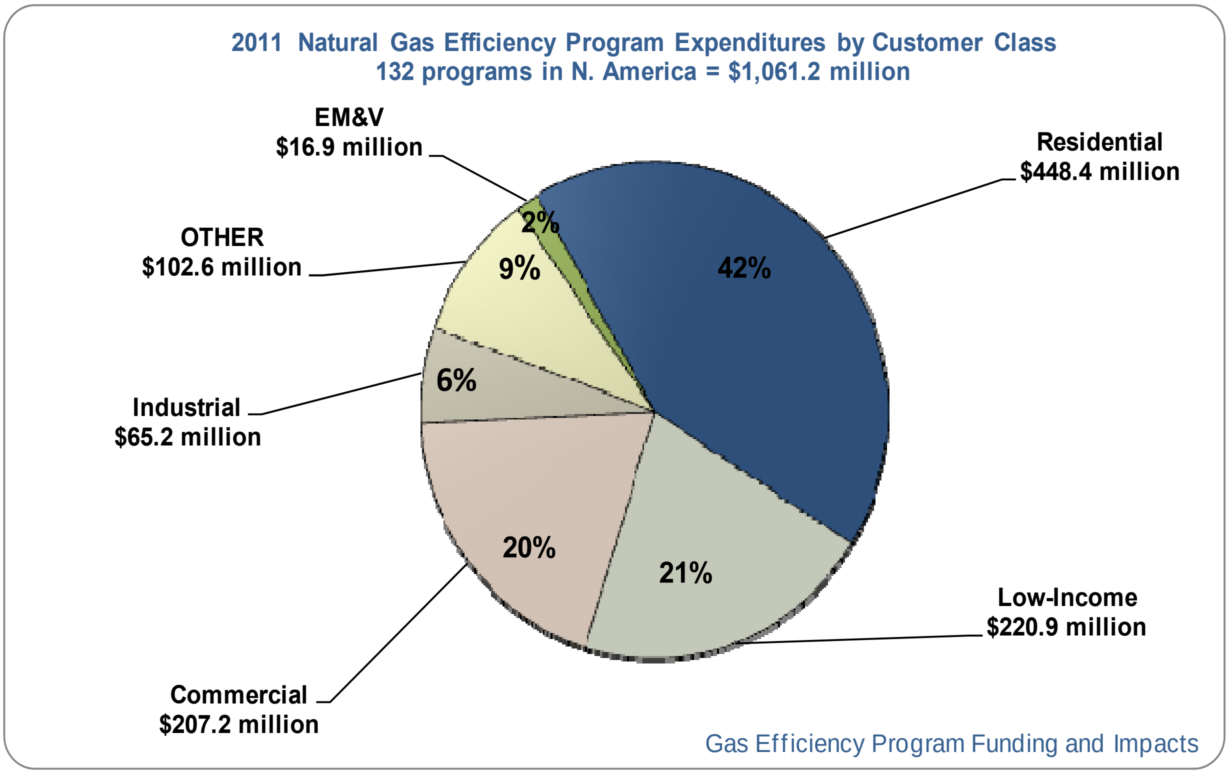


Program funding in North America increased by 16 percent from 2010 to 2011 and is expected to grow 43 percent in 2012. In the United States, program funding grew 14 percent in 2011 from $838 million in 2010, and a 46 percent increase is expected in 2012. As can be seen, natural gas efficiency program spending, improved in 2011 relative to the 4.4 percent growth seen from 2009 to the 2010 program year.

In fact, a comparison of 2011 actual efficiency expenditures to the aggregate 2011 budget that was reported during the previous survey cycle (for all companies participating in both surveys) indicates that U.S. programs spent 81 percent of the $1.19 billion 2011 efficiency program budget (compared to 73 percent of the 2010 budget). In North America, programs spent 82 percent of the $1.3 billion budget that had been reported for the 2011 program year. This cautious rebound in spending is mainly attributed to the economic recovery, albeit a sluggish one.

A look at 2011 natural gas efficiency program expenditures across sectors shows that North American utilities apportioned 42 percent of funding for residential programs, 21 percent for low-income, 20 percent for commercial, six percent for separate industrial programs, and 12 percent for other program activities, including EM&V (see Figure 6).

Figure 6

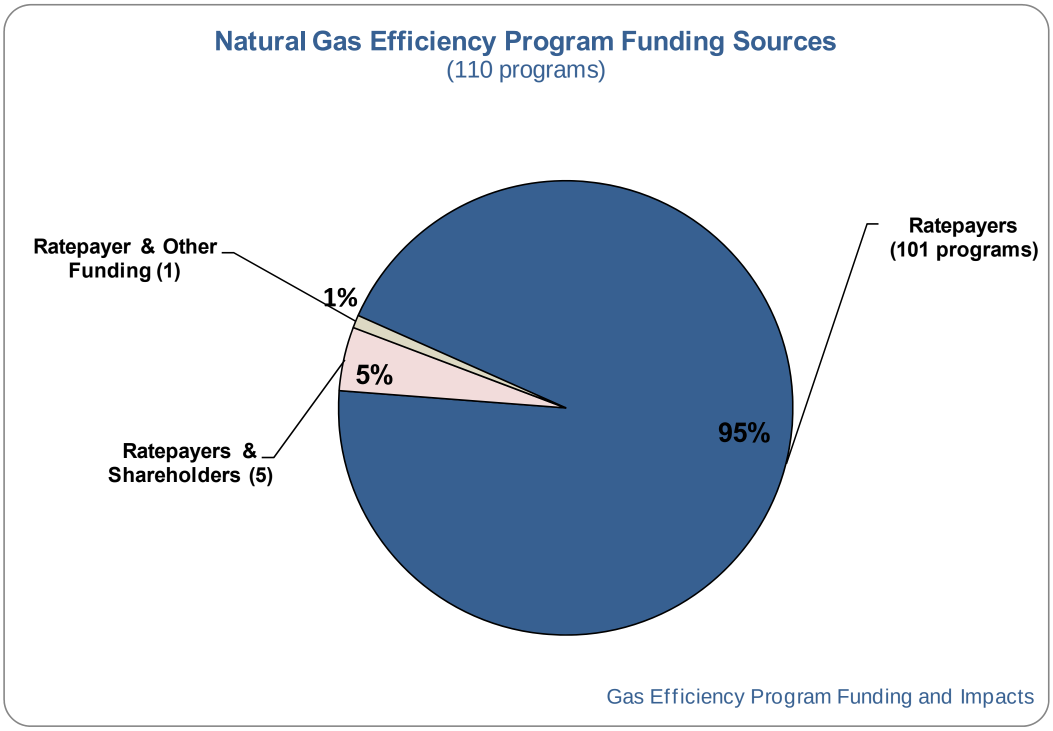


The other category includes expenditures that were not provided by customer segment. Also in this category are programs that cross-cut residential and non-residential customers segments. These include baseline studies and market research (including technology and market trials and pilot programs), planning and project development, consultation and cost effectiveness analyses, EM&V, market transformation programs, marketing (including statewide marketing and special projects such as non-profit kits), non-program specific administration costs (e.g., salaries, transportation, rebate processing), information systems upgrades (including tracking systems), conservation and efficiency education (e.g., school-based, online calculators, community education pilot), efficiency and technology training, and regulatory and state oversight expenses (e.g., third-party alternative filings).

Also included under other expenses are carry-over funds from prior program year, government partnerships, codes and standards, product development, emerging technologies, demand-side management coordination and integration, workforce education and training, state home improvement and conservation loan subsidies, financing programs, financial audit fees, building operator certification, solar thermal water heating, renewable energy, and agricultural programs.

Figure 7 shows the distribution of natural gas efficiency program funding among sources in 2011. Ninety-five percent of programs are funded solely by ratepayers (via base rates, system surcharges or natural gas efficiency tariffs), five percent by shareholders and ratepayers, and one percent via ratepayer and other funding.

Figure 7



Based on 94 survey responses, utilities disbursed from 0.0007 to 15 percent of net natural gas distribution revenues (net of gas costs) for natural gas efficiency programs in 2011. The median spending was 1.6 percent of net distribution revenues. Of the 94 responding companies, 36 used less than one percent of net distribution revenues for natural gas efficiency programs, 37 used one percent to less than five percent, and 18 spent five percent or more.

Natural Gas Efficiency Program Savings Impacts

Estimated 2011 annual natural gas savings impacts were reported for 116 programs by customer class. Respondents were requested to report energy savings realized by gas efficiency measures during the 2011 program year. This includes calendar year savings from natural gas efficiency measures already in place on the first day of the year (i.e. installed prior to 2011) as well as incremental savings realized from new measures implemented during the year. Some respondents were limited by the manner in which they track and report energy savings and thus did not provide annualized savings as defined above (with pre-existing measures and participation taken into account) but rather reported only incremental, or first-year Therm savings.

Data were not available for a number of respondents, either because savings are not tracked or not yet available for 2011. In some of these cases, estimates were provided based on prior year data. While the majority of respondents provided calendar year savings accumulated in 2011, some were able to report only for the most recent program year (with, for example, some program months falling in 2010 and some in 2011). Where data were not available by segment, a slight percentage of respondents reported overall savings in the "Other" category.

Respondents were also asked for gross impacts as well as net impacts—that is, to exclude free riders, spillover, savings due to government mandated codes and standards, reduced usage owed to weather or business cycle fluctuations, and reduced usage because of natural operations of the marketplace (e.g., higher prices). Seventy-six percent of respondents provided gross impacts, including a portion that reported both net and gross savings. The balance of respondents provided only net savings, corresponding to 13 percent energy savings in the U.S. and 26 percent of energy savings in North America, respectively.

Many respondents report deemed savings—a set calculation of savings per measure, developed pre-installation, with built-in assumptions regarding free ridership and other specifications. Some respondents were unable to separate low-income program savings from overall residential program savings, while others combined commercial program savings with residential impacts. Still others included savings for multi-family programs with C&I program savings. These combined categories represent a very small percentage of the data. Given that the reporting methodology varied among respondents, natural gas savings data should be regarded as estimates rather than exact figures.

As shown in Table 21, in 2011 U.S. utilities saved 1.25 billion Therm (or 125 trillion Btu) through natural gas efficiency programs, thus avoiding 6.5 million metric tons of carbon dioxide emissions (CO_2). Natural gas savings in North America were 2.04 billion Therm (or 203.8 trillion Btu), the equivalence of 10.6 million metric tons of avoided CO_2 emissions. For a breakdown of savings impacts by region, see Appendix D.

Table 21

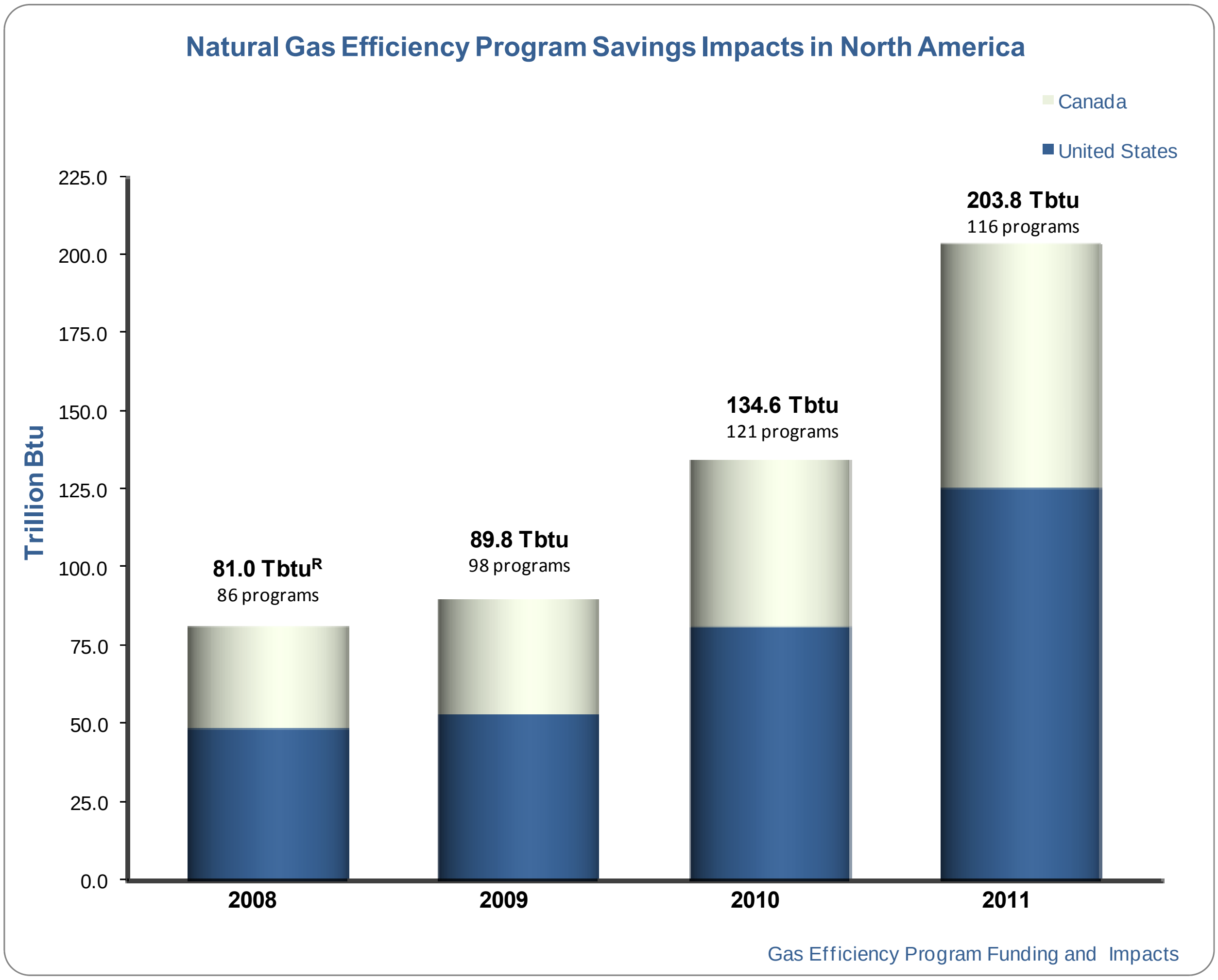
2011 Natural Gas Efficiency Program Savings Impacts by Customer Segment (Million Therm) - 116 Programs			
Sector	**United States**	**Canada**	**N. America**
Residential	365.7	129.8	495.5
Low-Income	63.9	2.5	66.3
Commercial	418.1	159.6	577.7
Industrial	299.6	142.6	442.2
Other[1]	104.9	351.6	456.6
TOTAL[2]	**1,252.2**	**786.1**	**2,038.3**

[1] The other category represents cross-cutting programs similar to those discussed under *Program Expenditures* on page 34.

[2] Subcategories might not add up exactly to reported totals due to rounding.

Figure 8 shows natural gas efficiency program savings from 2008 through 2011. This comparison is for illustrative purposes, because this growth cannot entirely be attributed to new and expanded programs but also to differences in survey samples from one year to the next.[8]

Figure 8



In the United States, natural gas efficiency program savings grew 55 percent in 2011 to 125.2 trillion Btu (from 80.8 trillion Btu in 2010). Savings in North America increased 51 percent, from 134.6 Btu in 2010 to 203.8 trillion Btu in 2011. While these savings growth rates are similar to those seen in the prior year, some can be attributed to changes in the reporting methodology. Regardless these growth rates are quite high, particularly when compared to the 2008-09 one-year growth rates of 9.3 percent and 10.9 percent, respectively for the U.S. and North America.

One likely explanation is the lag that often occurs between efficiency program outlays and the realization of savings associated with these program investments. For example, in 2009 U.S. programs invested $802 million dollars (a 42 percent growth from prior year spending), and in North America, spending reached $870 million (a 38 percent increase from the prior year). Spending continued to rise in 2010, although at much slower rate (4 and 5 percent, respectively, in

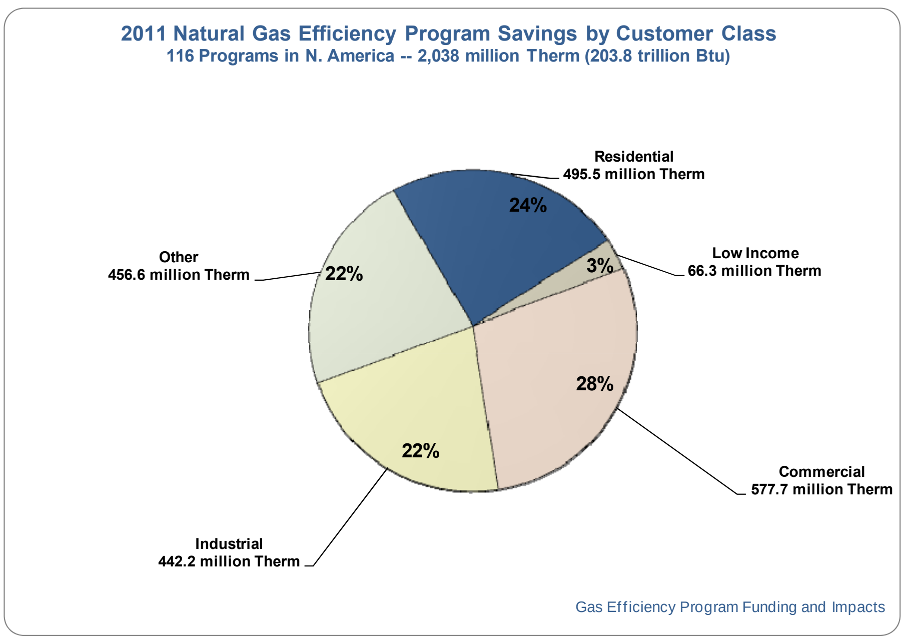
[8] Also note that the savings impacts methodology changed for 2011, reporting primarily gross savings, while in prior year, energy savings represented predominantly net savings.

the U.S. and in North America), and it grew more in 2011 (14 and 16 percent, respectively). Also of the 116 programs for which 2011 energy savings are reported, 28 percent were launched in 2009 (26 programs) and in 2010 (six programs). Thus, these new programs account for some of this growth, particularly since new programs often ramp up implementation gradually, and for many programs, savings are evaluated only after a one-year implementation period. Finally, as discussed earlier, 47 percent of respondents reported that they expanded their efficiency programs in 2011.

A look across segments at 2011 natural gas efficiency in the United States shows that 29 percent of energy savings are attributed to residential programs, 5 percent to low-income activities, 33 percent to commercial programs, and 24 percent to industrial accounts. Eight percent of U.S. natural gas savings is classified as “other,” representing data not allocable by customer class and including estimated savings for education, general outreach, codes and standards, and pilot programs.

In North America, residential program savings account for 24 percent of overall savings, low income program savings for 3 percent, commercial savings for 28 percent, and industrial savings for 22 percent. Twenty-two percent of N. American natural gas savings is classified as “other” (see Figure 9).

Figure 9



In the U.S. annual natural gas savings per efficiency program participant averaged 12.9 percent for residential participants and 14.1 percent overall. Natural gas savings per year averaged 281 Therm per U.S. customer overall (compared to an average 187 Therm/year in 2010) and 99 Therm per residential customer per year (compared to an average 76 Therm/year in 2010). Residential energy savings translate to average cost savings per customer of $107 on annual energy bills, compared to 2010 average avoided costs savings of $62 annually per residential customer.[9]

[9] Natural gas efficiency program data for both participant counts and annual savings were available for 91 U.S. programs. Average cost savings were derived from survey data for the 91 programs as well as Energy Information Administration (EIA) 2011 consumption data per company by end use and EIA 2011 national average natural gas residential end-use price.

III. Natural Gas Efficiency Program Planning and Evaluation

Survey respondents were asked to describe their approach to natural gas efficiency program planning, measurement and evaluation. The majority of respondents (83 percent) indicated that they have some form of evaluation, measurement and verification (EM&V) program. Forty-six percent of respondents (51 of 112) completed a full scale study or smaller market assessment (or some form of efficiency potential, baseline, or feasibility study) before implementing their natural gas efficiency programs.

However, not all were able to report EM&V expenditures and budgets for one of the following reasons: EM&V funds form part of the administrative budget, in-house evaluations are covered under other program expenses, incremental costs are not itemized, no evaluation report is due this program year, and contract negotiations with third-party EM&V vendors are ongoing.

EM&V Expenditures and Budgets

EM&V expenditures for the 2011 program year were obtained for 74 programs, and 2012 EM&V budgets were provided for 67 programs. EM&V expenditures exceeded $15 million in the U.S. in 2011 and are estimated to reach $34.5 million in 2012—a 123 percent increase. In North America, 2011 EMV spending approached $16.5 million and is expected to surpass $36 million in 2012 (see Table 22). These expenditures are much higher than those reported in 2010 (65 and 67 percent higher than the $9.4 and $10.1 million reported for the U.S. and North America, respectively, in 2010).

Table 22

Evaluation Measurement & Verification Expenditures and Budgets		
Region	2011 Expenditures ($) 74 Programs	2012 Budget ($) 67 Programs
United States	$15,467,972	$34,530,841
Canada	$1,414,814	$1,674,032
N. America	$16,882,786	$36,204,873

Program administrators conduct impact evaluations in varying ways. In 69 percent of programs (75 of 109) the utility is responsible for conducting the impact evaluation, in 8 percent (or 9 programs) the evaluation is under the purview of the regulator, and in 13 percent (14 programs) and independent EM&V monitor oversees the impact evaluation. The utility and the regulator share this responsibility in three percent of programs (three programs), and the utility and EM&V monitor work together in six percent (or seven programs).

When the utility is the primarily in charge of the evaluation function, the evaluation is conducted by in-house staff in 58 percent (or 53 of 99 programs), by an evaluation consultant in 27 percent of programs (25 programs), and by both internal staff and outside agent in 15 percent (or 14 programs). In the latter case, in-house staff may oversee and coordinate multiple independent evaluation consultants that are conducting impact evaluations and process assessments.

Evaluation Reporting Requirements

Ninety-six percent of respondents (109 of 113) indicated that they are required to report natural gas efficiency program impacts at regular intervals to their regulator or other authority. Others are requested to submit informal evaluations instead of a formal impacts report. When asked how often evaluators must submit a program report, respondents selected one or more timeframes, depending on the type of evaluation and intended recipient.

Table 23 shows the reporting cycles required by regulators for natural gas efficiency program impact evaluations. Seventy-six percent of respondents are required to submit an annual report at minimum. Some are required to report more frequently (e.g., semi-annually, quarterly, and/or monthly), while others report less frequently (e.g., once in three years, in five years or in six years). Eighty-eight percent are required to include gas savings in their report to the reporting authority (regulator or other state authority). Thirty-six percent of these respondents report net gas savings impacts, 47 percent report gross savings, and 17 percent include both in their report.

Table 23

EFFICIENCY PROGRAM REPORTING REQUIREMENT (109 programs with one or more reporting cycles)	
REPORTING FREQUENCY	**PROGRAMS**
Monthly	16
Quarterly	38
Annually	83
Semi Annually	9
All of the above	3
Other	6

Energy Savings Evaluations and Cost-Effectiveness Tests

When assessing annual energy savings derived from direct impact natural gas efficiency programs, 47 percent of respondents (51 of 109) determine savings at the individual program level, six percent (or six programs) at the overall portfolio level, and 32 percent (or 35 programs) at both levels. The remaining 15 percent assess direct impact activities other methods alone or in conjunction with individual and overall assessments. These include assessments at the measure level and by customer segment.

A number of programs also assess indirect impact efficiency programs (e.g., contractor certification, conservation education, energy audits, and building operator or contractor training). Nineteen percent of respondents (21 of 112) evaluate energy savings derived from such programs.

Cost effectiveness is evaluated in 107 of programs. When asked at what level they assessed cost-effectiveness, 103 respondents answered the question as follows: 34 percent (or 35 of 103 programs) are assessed at the individual program level, 13 percent (or 13 programs) at the portfolio level, and one percent (or one program) at the customer segment level. Thirty-seven percent (38 programs) determine cost effectiveness for both individual programs and the overall portfolio, and three percent (or three programs) assess cost effectiveness for both individual programs and by customer segment. The remaining 13 percent (13 programs) conduct tests at all three levels.

Table 24 shows how respondents answered when asked to identify all tests used to determine cost-effectiveness. The most prevalent test is the Total Resource Cost test (TRC), used by 84 percent of respondents (81 of 106), whereas the Societal Cost Test was least used—by 28 percent of respondents. Nineteen percent (or 20 respondents) reported using all five tests. Other includes Program Administrator Cost (PAC) test, tests done only at application time and based on engineering estimates, and payback periods for low income programs.

Table 24

TESTS USED TO DETERMINE NATURAL GAS EFFICIENCY PROGRAM COST-EFFECTIVENESS[10] 106 programs with one or more test	
TEST TYPE	**PROGRAMS**
Participant Test (PCT) Calculates quantifiable costs (e.g., out of pocket expenses of participating in program) and benefits (e.g., reduction in utility bill, rebate payments, tax credits) to participating customers	47
Ratepayer Impact Measure (RIM) Applies only to utility programs—measuring impact on all consumer bills/rates because of changes in utility revenues and operating costs due to program implementation	43
Societal Cost Test (SCT) Broader version of TRC adopting a societal perspective—measuring not only participants' and utility's costs but also externality cost and benefits (e.g., environmental impacts)	30
Total Resource Cost (TRC) Measures net program costs—including both participants' and utility's costs (e.g., equipment and installation, operation and maintenance and other related costs of participant and utility) and benefits (e.g., avoided supply costs, natural gas delivery cost reductions, tax credits)	90
Utility Cost Test (UCT) Narrower version of TRC—excluding participant costs and measuring net costs incurred by program administrator (e.g., customer rebates and other financial incentives) at the utility (UCT applies) or at other organization (PAC applies)	60
Other	6

Tracking Greenhouse Gas Emission and Source Energy as a Measure

Nineteen percent of respondents (18 of 113) indicated that a reduction of greenhouse gas (GHG) or carbon emissions is a performance target for their natural gas efficiency program. Of the 18, 13 respondents (or 12 percent) track such reductions. The other five, although they do not track

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[10] For a thorough description of cost tests, see *Model Energy Efficiency Program Impact Evaluation Guide*, A Resource of the National Action Plan for Energy Efficiency, November 2007, www.epa.gov/cleanenergy/documents/evaluation_guide.pdf

carbon emissions, do consider GHG reductions when selecting cost effective measures. Three other respondents do not consider emissions reduction as a performance measure, yet they track it and, in some cases, report their findings, while one other takes it into consideration.

When asked how they calculate energy efficiency gains for specific programs or measures, respondents indicated that they use source-to-site energy measurement in about 14 percent of programs (15 of 108), and site-only measurement in 85 percent of programs.[11] One respondent reported using both types of measurement. Forty-three percent of respondents employ their method because they required by the regulator or legislation, while 42 percent do so because of available resources, and 15 percent for other reasons. Twelve of the respondents that measure source efficiency provided reasons: eight percent said they were guided by regulatory or legislative requirement, 75 percent cited available resources, and 17 percent pointed to other reasons.

Forty-three percent of those programs that test site efficiency use this approach due to legislative or regulatory requirements, 43 percent because of available resources, one percent because of a combination of the two, and 13 percent for other reasons. Other reasons cited include: 1) projected savings are verified based on billing analysis; 2) traditional approach or common practice for utility-sponsored programs; 3) approach was needed to determine savings from direct use/fueling switching programs; 4) consistency with other utilities in collaborative, 5) consistency with electric planning; 6) a limitation to use deemed savings in the regulator-developed calculation, 7) in compliance with Energy Star standards, and 8) current practice for statewide programs.

[11] Source energy—also known as full fuel cycle analysis—is a more accurate measurement of efficiency. Site energy analysis accounts for energy used or consumed only by the end-user at the usage site. On the other hand, a full fuel cycle analysis takes into account not only onsite energy consumption but also consumption and losses during the production, generation, transmission and distribution cycles. This allows for a realistic comparison of relative efficiency among different technologies, especially when comparing the efficiency of natural gas applications from source to site with that of other fuels.

IV. Natural Gas Efficiency Regulatory Requirements and Cost Recovery Treatment

This section describes some of the regulatory and legislative requirements and allowances that govern natural gas efficiency programs in the United States, including state potential studies, efficiency program spending requirements, rules for low-income programs, recovery of direct program costs, lost margin recovery, financial incentives for well-performing programs, carbon offset programs, and fuel switching to natural gas. Data were provided for 113 U.S. programs, although not all respondents answered all questions.[12]

Potential Studies

Every so often state policy makers conduct potential studies through which they gather key data to inform their decisions pertaining to energy efficiency policies and objectives. The data might include baseline energy usage and other market statistics, economic outlooks, energy forecasts, implementation costs, and cost-benefit assessments for various efficiency program components. These studies help decision makers set achievable goals (in terms of investments, outcomes and timeframes), quantify energy efficiency as a resource, determine funding levels to attain goals, and forecast the long-term savings potential of energy efficiency investments.[13] According to survey responses, market studies were conducted in 14 states to assess the economic and efficiency potential of implementing natural gas efficiency programs. New Potential studies are in progress in five states. Table 25 shows the year in which the most recent studies were completed for each of the states.

Table 25

State Energy Efficiency Market Potential Studies Completed in 14 States & in Progress in 5 States		
Most Recent Year for Completed Study	**Number of States**	**State List**
2004	1	UT
2005	1	WI
2008	2	IA, NJ
2009	5	MA, MN, NH, OH, PA, CAN
2010	5	CA, IL, NY, OR, WA
New Studies In Progress	**5**	CA, MA, MI, NM, VT

[12] Appendix A shows natural gas efficiency program practices and regulatory requirements by state and for Canada. This includes market assessment studies, mandated utility funding for natural gas efficiency programs, requirements for low-income residential programs, approved recovery for direct program costs and lost margins, utility performance incentives, fuel switching and source-to-site energy measurement.

[13] More information is provided in a *Guide for Conducting Energy Efficiency Potential Studies*, A Resource of the National Action Plan for Energy Efficiency, November 2007, http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf

Natural Gas Efficiency Program Requirements and Policy Goals

Many state policy makers have mandated that utilities invest in natural gas efficiency programs. Twenty-nine states require utilities to fund efficiency programs, by way of regulatory order (in 22 states), legislative bill (in 11 states) or through both regulation and legislation (in 16 states).

The goals that drive efficiency program funding requirements are energy conservation and savings (82 programs in 29 states), customer dollar savings or bill reduction programs (45 programs in 22 states), greenhouse gas or carbon emission reductions (32 programs in 13 states), "green jobs" creation (15 programs in six states), renewable portfolio standards (9 programs in seven states), reduced usage for low income customers (36 programs in 17 states), to meet electric DSM requirements (8 programs in six states), and to reduce supply/infrastructure costs (14 programs in eight states). Twenty-nine states have set more than one goal, of which two pursue all eight objectives (see Table 26).

Table 26

Policy Goals Governing Efficiency Program Implementation		
Goals	Number of Programs	Number of States
Increase Energy Savings	82	29
Reduce Customer Energy Bills	45	22
Reduce GHG or Carbon Emissions	32	13
Create Green Jobs	15	6
Renewable Portfolio Standards	9	7
Reduce Usage for Low Income Customer	36	17
Meet Electric DSM Requirements	8	6
Reduce Supply/Infrastructure Costs	14	8

Rate Structures and Regulatory Treatment Aligned with Utility and Energy Efficiency Goals

An investor-owned utility has an intricate accounting and rate setting methodology to recover its costs. Many resources explain utility accounting and rate design in depth.[14] For the purpose of this report a simplified, brief description is provided as background for relaying the policies that have been progressively adopted to protect utilities from losses associated with energy conservation practices and to incentivize them to invest in energy efficiency programs.

[14] For a thorough explanation of utility rate-design policies that support utility commitments to efficiency programs, see *Aligning Utility Incentives with Investment in Energy Efficiency*, A Resource of the National Action Plan for Energy Efficiency, November 2007, http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.
Also visit the AGA *Rate Roundup: A Periodic Update on Innovative Rate Designs* web page: http://www.aga.org/our-issues/RatesRegulatoryIssues/ratesregpolicy/rateroundup/Pages/default.aspx

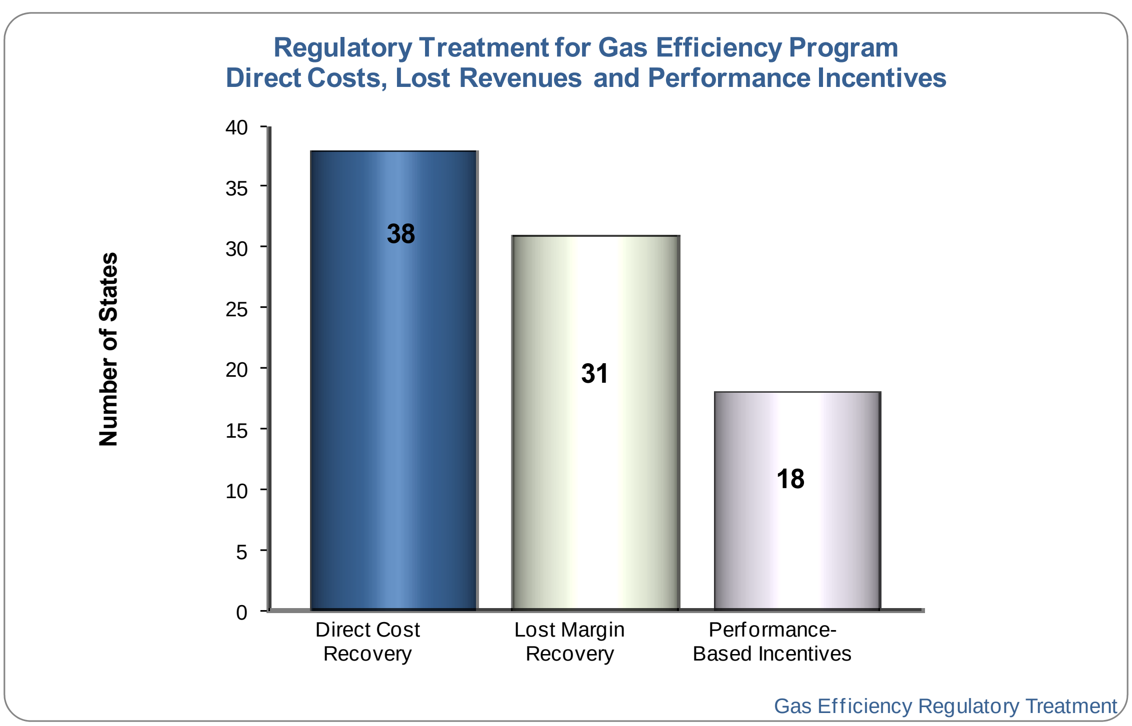
When setting rates, an investor-owned utility negotiates with its regulator (public utility/service commission) what it is permitted to charge its customers in order to be able to continue to meet its obligation to serve its customer base. These rates are calculated to match the revenue requirement of the utility, allowing it: 1) to recover its incurred costs—both variable and fixed, 2) to pay the interest cost on its capital debts, and 3) to earn a return for shareholders on investments. The profit margin is approved by the regulator who sets the rate of return (or percentage) the utility may earn on its equity (a return on equity or ROE).

In traditional rate designs, a portion of fixed costs are recovered via a volumetric charge or a price per Therm. With this rate structure—because energy consumption varies while infrastructure costs remain fixed in the short term—the utility is at risk of under-recovering its fixed costs should customers reduce their gas consumption. (In the long-term, it is thought that reductions in usage should eventually result in reduced natural gas supply capacity requirements and thus decreased capital costs, thereby eventually reducing costs for customers.) Also decreased energy usage that results from successful efficiency program implementation can negatively impact the utility's revenues, furthering the disincentive for utilities to promote efficient energy use.

With growing interest in energy conservation and demand side management, policy makers have increasingly approved mechanisms that allow utilities to recover the direct costs and the margin losses associated with implementing energy efficiency programs. Policy makers have also approved financial rewards to shareholders for investments in energy efficiency programs—quantifying the value of these demand-side programs and treating them similar to supply side resource investments (e.g., distribution infrastructure, transportation capacity, underground storage, etc.).

Respondents identified 38 states that allow utilities to recover the direct costs of natural gas efficiency programs, 31 states that permit recovery of lost margins due to efficiency program implementation, and 18 states that financially reward utilities for well-performing natural gas efficiency programs (see Figure 10).

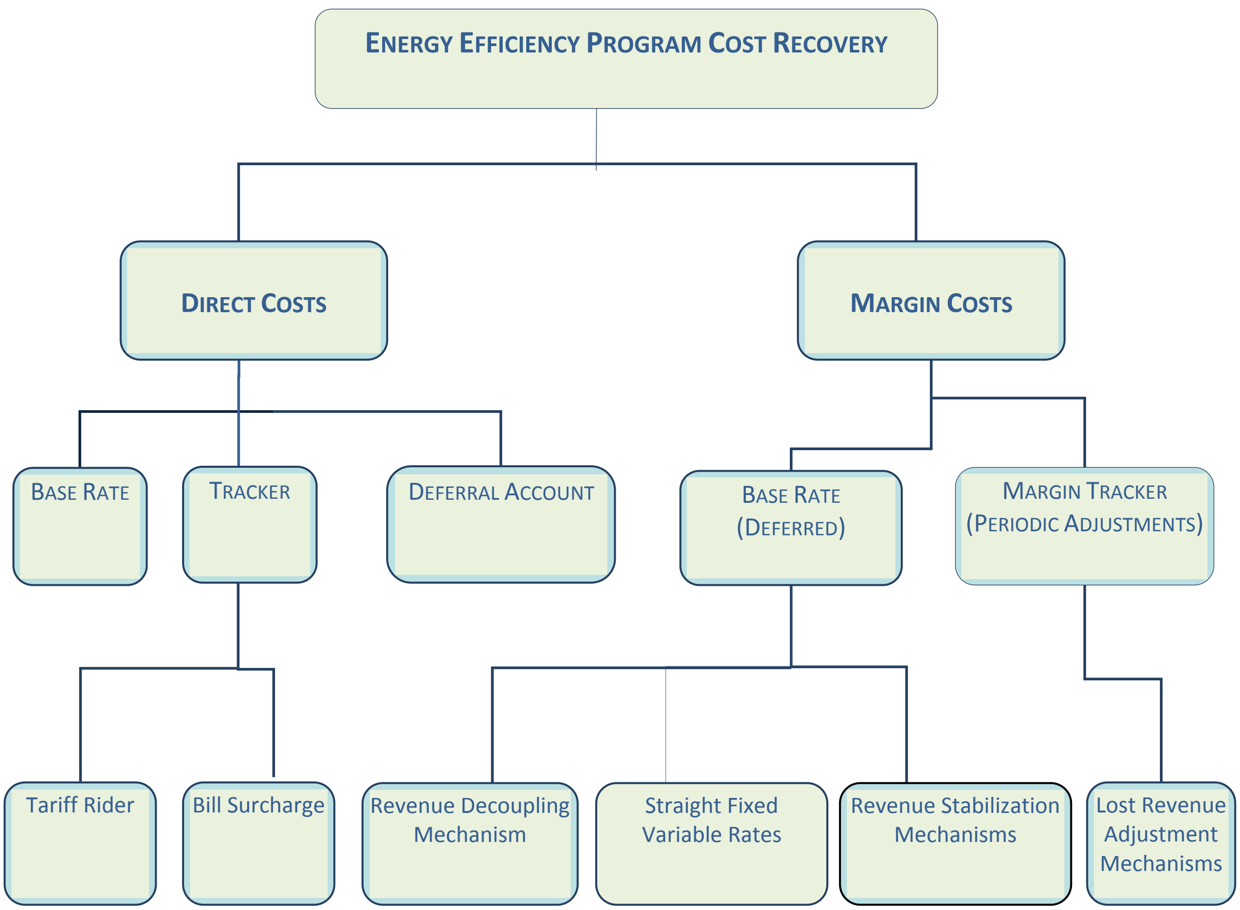
Figure 10



Recovery of Energy Efficiency Costs

Energy efficiency program costs are divided into two categories: direct costs and margin costs. Direct costs may be recovered in three ways: Through base rates, trackers (e.g., tariff riders, bill surcharges), or deferral accounts. Margin losses (and gains) are adjusted and recovered in one of two ways: Deferred and recovered via base rates (e.g., revenue decoupling, straight fixed variable rates, and rate stabilization) and/or via margin trackers (e.g., lost revenue adjustment mechanisms or LRAMs). These mechanisms are discussed in more details in the following sections. Figure 11 presents a summary of cost recovery methods.

Figure 11

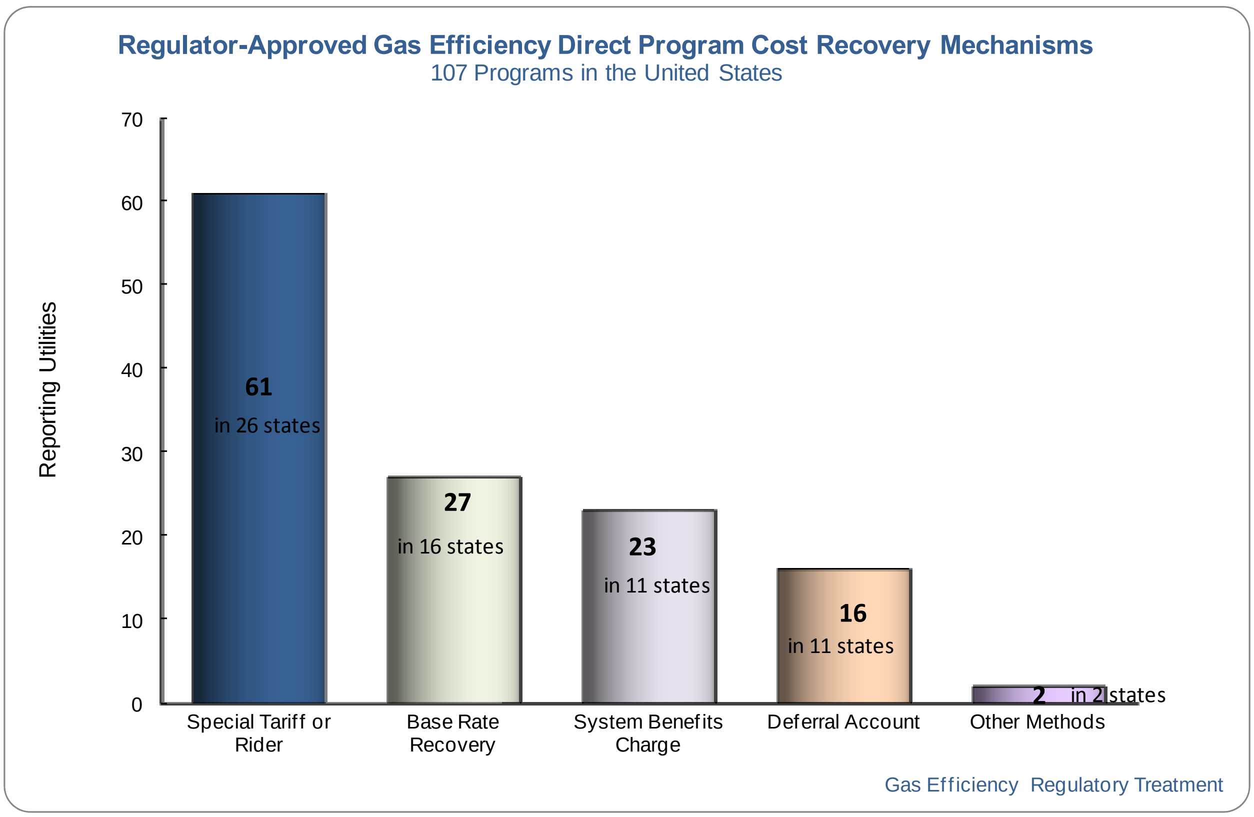


Direct Program Cost Recovery

Direct cost recovery allows utilities to pass through efficiency costs to customers in one of three ways: 1) Program costs are treated as expenses that are embedded in base rates (or the charge per Therm) in a general rate case. 2) Efficiency program costs are recovered via a separate tariff rider or a surcharge on customer bills (also known as system benefits charge), and the surcharge amount may be adjusted periodically to correct for over or under-recovery of efficiency costs. 3) Program expenditures accrue and are tracked in a balancing account for amortization and later recovery from customers over a period of time.

According to survey respondents, special tariffs or efficiency riders are currently the most common method for recovering program costs. Sixty-one companies in 26 states use a special efficiency or conservation tariff rider, 27 utilities in 16 states embed natural gas efficiency program costs in base rates, 23 companies in eleven states apply a mandated system benefits (or public goods) surcharge to customer bills, and 16 utilities in eleven states track expenditures in a balancing account for amortization and later recovery over a period of time (see Figure 12). Two other companies in two states used other methods to recover program costs.

Figure 12



Lost Margin Recovery

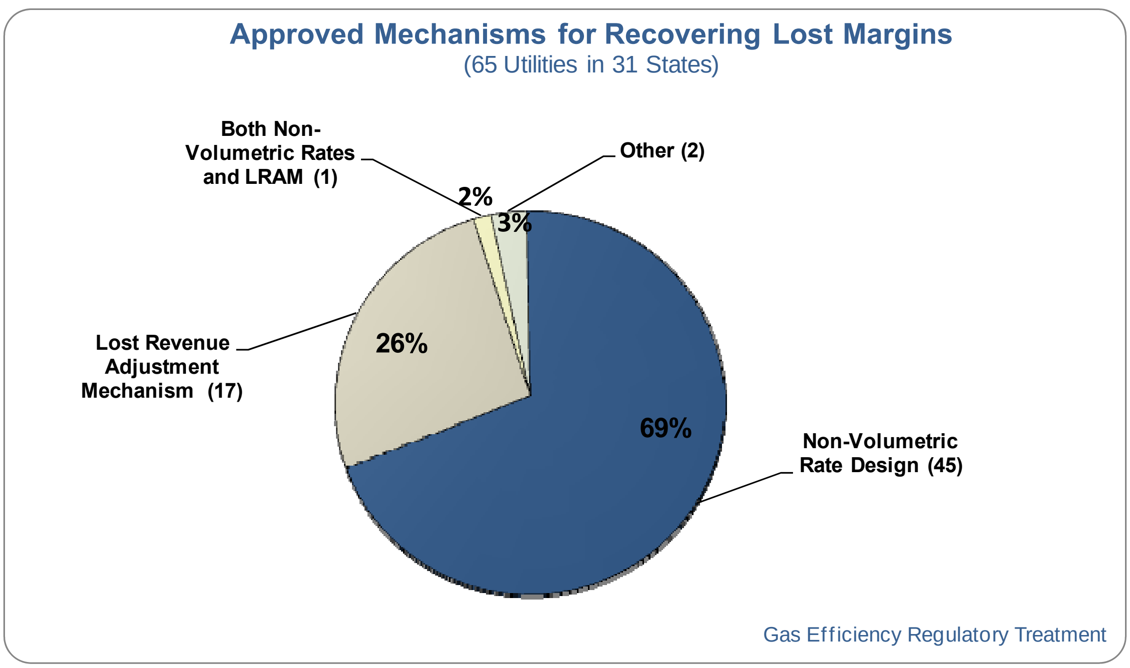
Recovery of margin losses and revenue shortfalls due to efficiency program implementation are increasingly allowed in more states, thereby removing the disincentive to invest in natural gas efficiency programs due to falling revenues. Sixty-five programs operate in the 31 states identified earlier as having authorized a mechanism for recovering lost margins correlating to efficiency implementation. Additionally, decisions on lost margin recovery are pending for two other utilities in two states. Thirty-nine respondents reported, on the other hand, that they are not allowed to recover the revenue losses resulting from implementing efficiency programs. Methods for recovering efficiency-related lost margins vary.

NON-VOLUMETRIC RATE STRUCTURES form one method of recovering lost margins. With such rate designs, utilities may collect revenues from customers independent of Therm usage. Here margin recovery is not applied on a per Therm basis but approximates a per-customer basis. These mechanisms include revenue decoupling, straight fixed variable (or SFV) rates, and rate stabilized mechanisms.

LOST REVENUE ADJUSTMENT MECHANISM OR LRAM is the other method of recovering lost margins. It requires the utility to identify unrecovered margins associated with efficiency programming, track them over a time period, and recover them after the fact. In this case revenues continue to be recovered on a Therm usage basis; however, rates are adjusted to correct for under- or over-recovery of margins. This type of margin true up is also generically referred to as conservation adjustment mechanism.

As shown in figure 13, of the sixty-five utilities that are allowed to recover lost margins in the U.S., forty-five utilities (in 24 states) have a non-volumetric rate design, seventeen (in 11 states) use a lost revenue adjustment mechanism (LRAM), one (in one state) has both non-volumetric rates and a margin tracker, and two others (in two states) use another method to recover lost margins. Of the 18 utilities that have a LRAM or margin tracker (or both LRAM and non-volumetric rates), two indicated that their margin adjustments are capped or limited to a certain percentage of revenues. Lost revenue recovery is pending in two states.

Figure 13



Revenue decoupling mechanisms have different names, such as conservation enabling tariff, conservation incentive program, conservation margin tracker, conservation rider, and so on. Decoupling breaks the link between utility revenues or profits and gas throughput (or delivered volumes). It may be applied to total revenues or on a revenue-per-customer basis. When the recovered revenue varies from the allowed recovery amount, it is trued up via periodic rate adjustments to adjust the under or over-recovery. Revenue variances specific to efficiency may be tracked in a separate balancing or adjustment account and applied to the next rate adjustment. Decoupling takes on different forms: 1) full revenue decoupling, 2) partial revenue decoupling where only a portion of losses are recovered, and 3) revenue decoupling with certain restrictions (see below).

In some cases, the margin shortfall or surplus, specific to efficiency investments, is allowed to accrue in a deferral account, treated as a regulatory asset, and the recovery is amortized over a period of time, normally applied to the class of customers benefiting from efficiency savings. Sometimes utilities may charge an annual interest rate on the unamortized balances, thus recovering the carrying cost on the deferred margins.

Partial revenue decoupling limits margin recovery to a specific percentage of revenues or must be equal to the achieved natural gas cost saving. Revenue decoupling with restrictions may involve caps on the authorized ROE or other limits on regulated earnings.

A **revenue stabilization mechanism** (also known as rate stabilization) is another form of non-volumetric rates, where utility revenues are de-linked from the amount of gas throughput. Rate stabilization combines lost margin recovery and recovery of operating costs within one mechanism. Here rates are adjusted periodically to adjust for variances in returns from the regulator-authorized return on equity (ROE) and for utility cost variances since the last rate adjustment.

With **straight fixed variable rates**, there are no revenue impacts resulting from efficiency programming, because most or all fixed costs are recovered via a non-volumetric charge. The per-customer charge remains stable regardless of consumption variances (approximating a flat monthly fee).

Of the 45 utilities in the 24 states that have non-volumetric rate design, 19 (in 14 states) have full revenue decoupling, five (in four states) have partial revenue decoupling, eight (in seven states) have revenue decoupling with restrictions, and seven (in seven states) have a non-specified type of revenue decoupling. Four others (in three states) have a straight fixed variable (SFV) rate design, and two (in two states) has a rate stabilization mechanism.

Table 27

NON-VOLUMETRIC RATE STRUCTURES 45 NATURAL GAS UTILITIES IN 24 STATES[1]		
MECHANISM	NUMBER OF COMPANIES	NUMBER OF STATES[2]
Full Revenue Decoupling	19	14
Partial Revenue Decoupling	5	4
Revenue Decoupling with Restrictions	8	7
Non-Specified Revenue Decoupling	7	7
Straight Fixed Variable	4	2
Rate Stabilization Mechanism	1	1

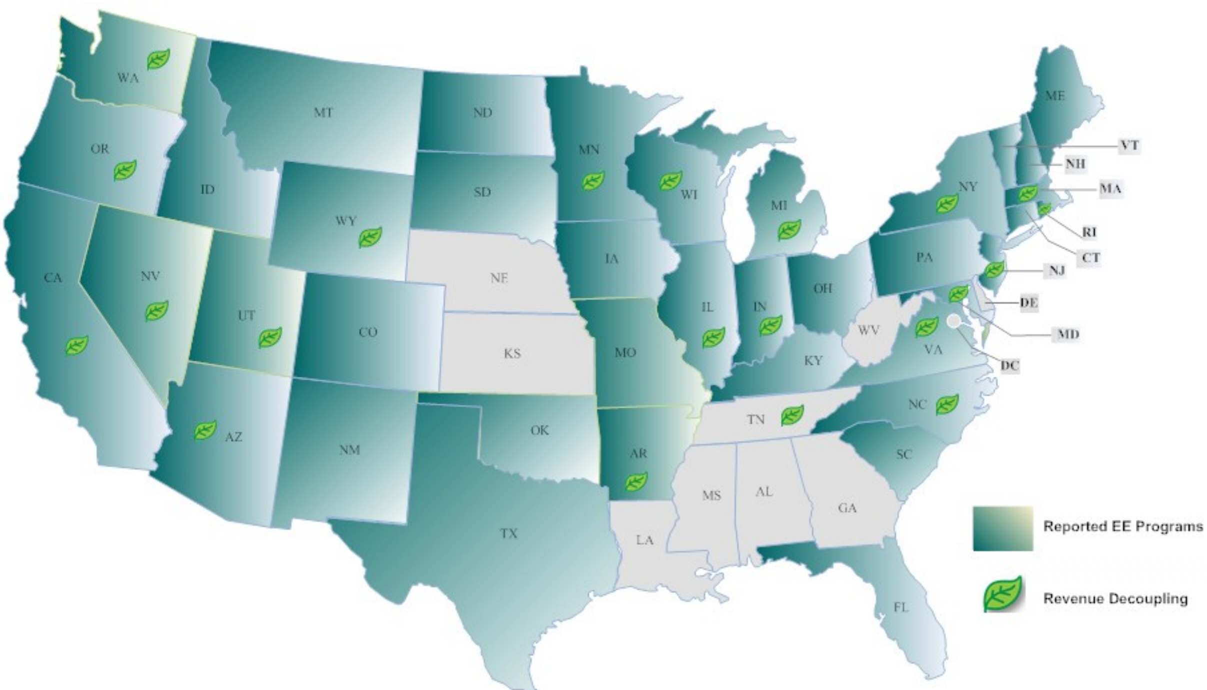
[1] The forty-five natural gas utilities include four that have both revenue decoupling and a margin tracker (or lost revenue adjustment mechanism).

[2] The same state may be represented in more than one category of non-volumetric mechanism

As seen in Figure 14, in 2011 natural gas efficiency programs are found in all states that allow the utility to segregate margin recovery from its natural gas throughput or delivered volumes.[15]

Figure 14

STATES WITH NATURAL GAS EFFICIENCY PROGRAMS AND REVENUE DECOUPLING – 2011 YEAR



Data Sources: *Non-Volumetric Rates and Cost Trackers Update (September 2012),* http://www.aga.org/our-issues/RatesRegulatoryIssues/ratesregpolicy/Pages/febr2011-innovative-ratesNon-volumetric-ratesandtrackingmechanisms.aspx and *2012 AGA Natural Gas Efficiency Programs Survey*

Utility Performance-Based Incentives

As mentioned earlier, recovery of efficiency program costs and associated lost margins removes the utility's disincentive to promote energy efficiency, thereby making program implementation revenue neutral. To incentivize investor-owned utilities to commit fully to efficiency program improvements and expenditures, regulators have gradually approved more mechanisms that financially reward utilities for making energy efficiency investments. Efficiency performance-based incentives for utilities involve three mechanisms: shared savings, performance targets and rate of return incentives.

SHARED SAVINGS mechanisms reward utilities either for investing in energy efficiency at pre-determined minimum spending levels or for making cost-effective efficiency investments. Financial incentives are calculated as a percentage of efficiency spending or as a percentage of the achieved net system benefits (the difference between efficiency costs and energy savings or other

[15] For an update on revenue decoupling and other rate designs per states, see *Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms, AGA Presentation Slide Deck* (July 2011), http://www.aga.org/our-issues/RatesRegulatoryIssues/ratesregpolicy/Pages/febr2011-innovative-ratesNon-volumetric-ratesandtrackingmechanisms.aspx

economic benefits). Awards are often capped at a specified dollar amount regardless of the rate applied to spending levels or net benefits. Commonly investors and ratepayers share the savings. In some cases, penalties are applied when programs fail to meet the minimum threshold.

PERFORMANCE TARGETS are often conditions for capturing earnings on efficiency investments. The pre-determined goals may be set at certain investment levels, total energy savings, the extent of cost-effective savings, or the numbers of units installed. Financial awards may be tiered according to performance thresholds: for example, for attaining at least a proportion of goals, meeting the target, or exceeding them. Also penalties may apply if the utility falls short of the minimum requirements. Also incentives may be capped, even if performance surpasses the maximum threshold and may involve a dead band, where incentives are suspended within this performance range.

RATE OF RETURN INCENTIVES allow earnings on natural gas efficiency expenditures either equal to the utility's authorized return on equity (ROE) or at an enhanced level—an added or bonus ROE applied to efficiency investments. Incentive structures may involve a combination of these three mechanisms, making performance targets a prerequisite to shared savings or returns on efficiency investments.

Thirty-eight natural gas efficiency programs are implemented in the 15 states identified earlier as having utility performance based incentives. When asked to identify all mechanisms that formed their incentives, they indicated having one of the following mechanisms: eight companies (in five states) have a shared saving mechanism, five (in four states) have a rate of return (ROR) mechanism, and 25 companies (in four states) have a bonus opportunity for meeting performance targets. Four have more than one incentive mechanism, and four have other mechanisms. Table 28 shows the various arrangements as reported by companies.

Table 28

UTILITY FINANCIAL INCENTIVE STRUCTURES SPECIFIC TO NATURAL GAS EFFICIENCY PROGRAM IMPLEMENTATION AND PERFORMANCE		
FINANCIAL INCENTIVE MECHANISMS	PROGRAMS	STATES[1]
Shared Savings	8	5
Rate of Return Incentive	5	4
Financial Reward or Bonus Opportunity for Meeting Performance Targets	25	4
A Combination of Mechanisms	4	4
Other Mechanisms	4	4

[1] The same state may be represented in more than one incentive category

According to ten survey companies, they are eligible to share between 7 percent and 33 percent of ratepayer savings (the median share was 13 percent). Of the six companies that have a rate of return incentive, four earn an ROR on natural gas efficiency investments equal to its authorized return on equity (ROE), one earns a rate greater than the authorized ROE, and one has both ROR and bonus opportunity mechanisms.

Low Income Program Requirements

Specific to the low income customer segment, 67 percent of programs (72 of 108 respondents in 27 states) indicated that they are mandated (via ruling or legislation) to fund natural gas efficiency programs for this customer segment. Fifty-eight percent of these respondents (42 of 72) indicated that income-qualified programs are subject to cost-effectiveness test in 23 of these states

According to 83 of 107 respondents in 33 states (75 percent), the program administrator is required to use one or more regulator-selected cost-effectiveness tests to measure program performance in (some of these low income programs are not mandated by the state). This calculation must be based on net savings for 57 percent of programs, on gross savings for 36 percent, and on both net and gross for one percent.

Fuel Switching Allowances

Fifteen percent of U.S. respondents (16 of 106) reported that their regulator-approved natural gas efficiency program encourages fuel switching through financial incentives (e.g., rebates, loans and other benefits) to customers who install natural gas equipment in new homes, convert to natural gas from other fuels, or replace old equipment with new higher-efficiency natural gas equipment.

Green House Gas or Carbon Emissions Targets and Credits

Respondents were asked whether their state targets greenhouse gas (GHG) or carbon reduction as an explicitly and measurable goal, and twelve percent (or 13 of 101 respondents) said "yes." Four of the programs that operate within a GHG reducing state, indicated that the utility was able to earn credit on GHG-emissions reduction projects in the form of program cost recovery (two programs) and a return on investment (two programs). Similar regulator-approved earnings mechanisms are pending in two other states.

When asked whether they had sought regulatory approval for cost recovery or earnings on project investments where GHG emissions reduction is the primary goal, one of 106 respondents indicated that they had secured regulatory approval. Nine companies (in six other states) are exploring such options, and in two states decisions are pending.

V. Thoughts and Comments

Program administrators were asked to share their experiences with implementing natural gas efficiency programs. The following is an anecdotal account based on respondent observations regarding lessons learned, program delivery barriers, market penetration, and the most successful and innovative program features.

Delivery Barriers and Lessons Learned

Economic Climate and the Market: The lingering economic slowdown continued to pose a challenge for many natural gas efficiency programs in 2011, thus slowing momentum in program delivery and market penetration. In the more distressed areas, tight or shrinking resources made consumers more sensitive to the incremental cost of upgrading to higher efficiency equipment, thus discouraging them from taking advantage of appliance rebates and other financial incentives for improving energy efficiency. Many commercial programs were sluggish as well, as businesses continued to extend the life of their existing equipment via repairs or leasing rather than investing in new higher efficiency systems.

Mild weather and low natural gas prices also played a significant role in driving consumer behavior, giving efficiency less urgency in the decision-making schema. These factors, coupled with the expiration in 2011 of federal energy efficiency tax credits (which help drive utility rebate programs), negatively impacted participation levels in a number of programs.

The lack of new energy efficient gas technologies also limits new program opportunities. Another issue is the low stock of high efficiency gas appliances in many markets' white goods and box stores and the practice of relegating such high efficiency appliances to special order status. As discussed in this report and later in this section, efficiency program administrators have formed strong alliances with trade partners to overcome such barriers.

Stringent Standards and Cost-Effectiveness: The dynamic of lower gas cost and inherent efficiency already existing in gas appliances makes it increasingly challenging to achieve cost-effectiveness and thus more difficult to justify implementing new natural gas efficiency programs. Compounding these hurdles to cost-effectiveness are new federal codes and standards (originating in the Energy Independence and Security Act 2007) and new Energy Star and DOE appliance and equipment standards, which may impact the future availability of certain natural gas measures as they are deemed not to be cost effectiveness. This concern regarding cost effectiveness is expected to persist as natural gas prices continue on a stable course and standards take effect.

For many, the issue lies in the method of assessing cost effectiveness. They would propose taking a new look at the standard regulator-approved cost effectiveness tests and underlying criteria to see how applicable they are to natural gas efficiency programs. One approach is to take into consideration all externalities when computing benefits (e.g., societal) and to consider in the savings calculation the entire natural gas supply chain, which is intrinsically efficient from wellhead to burner tip.

Realizing Further Energy Savings: Thus on the one side of the cost-effectiveness equation is the rising incremental or first-cost of adopting higher efficiency technologies and on the other side is the lower cost of natural gas, thereby elongating the pay-back period for the consuming home or business. These factors also impact the utility natural gas efficiency program implementation. Not only does it become more difficult to attain higher levels of savings year after year, but depending on how one evaluates the program, the value of these energy savings may not be sufficient to meet the investment cost.

Many factors affect the levels of energy savings that can be achieved: For instance, mature programs, which have already captured the more readily attainable (or "low hanging fruit" of) energy savings encounter more barriers to higher-level savings. Small utilities with a small customer base also face challenges as do programs in rural areas and those that have a high ratio of new housing in their service territories. Again code requirements, coupled with old housing stock (especially as these pertain to modified venting requirements for newer higher efficiency equipment) may also pose a significant barrier for residential prescriptive programs.

Other challenges to meeting natural gas energy efficiency goals occur in some combined gas-electric efficiency programs, where installing certain electric energy efficiency measures (e.g., compact fluorescent light bulbs or CFLs) create negative therm impacts due to an increase in the natural gas heat load resulting from the elimination of heat radiating incandescent lighting. The issue lies with the practice of attributing the negative therm impacts to effects of the natural gas efficiency program, even though the responsible measure originates in the electric efficiency program.

Besides working with trade allies, including contractors and installers of natural gas equipment, utility energy efficiency program administration are looking at new ways to achieve more savings: while individual measures (e.g., appliance replacement) are still important program components, more programs are pursuing deep energy retrofits and a total system approach to energy efficiency, where the most savings can be achieved.

Ramp-up Period and Participation Outcome: While some efficiency programs encountered strong (and sometimes unanticipated) participation levels, others got off to a slow start and ramped up after a push from advertising and other outreach efforts. Many factors influence participation outcomes, such as the influx of other sources of funding. For example, ARRA (stimulus) funds took precedence over utility funding and resulted in decreased participation in a number of utility-sponsored programs. Also in some areas, with multiple entities offering overlapping incentives within the same service territory (such as neighboring utilities or newly formed non-regulated fuel programs), the dynamic of multiple program offerings can create misunderstanding and confusion among customers as they decide in which program to engage. Clear communications and a simplified application process can offset such complications to the benefit of customers. Many programs are simplifying their application and rebate processing to respond to customer needs.

Others learned that commercial programs take longer than typical residential programs to ramp up and require a targeted marketing approach to reach the intended audience. Getting the whole house program off the ground also took longer than anticipated, requiring intensive communication and promotion. Besides ramp up periods, program administrators were faced with other time constraints. For instance, some spent more time on regulatory and EM&V issues than on program implementation activities.

To address these constraints, program administrators are fine tuning their programs and making them more flexible and adaptive to changes in the market. Some program administrators are exploring different marketing methods and new incentives for commercial and institutional customers, and they view multiple venues for promoting programs as a must. They also suggest that where conventional methods (e.g., mass marketing through the usual media outlets) is not effective, customer outreach and community-based approaches yield better results as does direct communication with market influencers (e.g., retailers, contractors, home builders, and realtors).

As mentioned, a number of programs were faced with unanticipated participation levels. For some, customer acceptance of rebate programs started stronger than initially expected. While at first glance, strong interest appears to be a positive outcome, it can be problematic if program implementers are caught off-guard. With equipment rebate programs being market-driven, it can be difficult for program managers to forecast participation and manage program budgets to consistently meet this demand throughout the program year. Regardless, it is important to begin imparting information about available funding at the beginning of each program year and to make certain that customers have regular access to this information. It is also important during a program launch year to build in a buffer under budget caps for unforeseen expenditures.

In one case, budget constraints were experienced during most of the program year because of very high participation levels and costs related to residential insulation, driven by third party contractors taking advantage of multiple rebates as well as new marketing techniques. As a result, the utility restructured its insulation rebates as well as the process in which rebate applications are submitted and approved. Other programs also responded to similar challenges by improving their rebate processing structure and tightening controls on rebate applications—some by implementing automated controls that limit the number of applications to specific budget limitations.

Customer Response: Respondents suggested again this year that customers are interested in being green *if* there are incentives to assist them in paying for upgrades. For long-standing programs, it was a challenge to continue generating enthusiasm for a twenty-plus year old programs. In many markets, residential customers responded favorably to subsidized, low-cost diagnostic or computer energy audits in conjunction with specific efficiency rebates such as attic and wall insulation and air sealing. Many program administrators place high value on the energy audit/assessment as a method to promote a whole system approach to energy efficiency. However, in one jurisdiction a condition to have an in-home energy audit as pre-requisite for rebate eligibility posed a barrier to entry, eliciting a degree of resistance from customers and skepticism toward the program that required more time and communication to overcome. Even then, program administers find the energy audit to be a valuable tool.

Market Allies: Having a strong alliance with trade partners goes a long way toward clearing the above-mentioned market hurdles. Trade allies (such as HVAC contractors, energy auditors, plumbers, and equipment dealers and retailers) play vital roles in efficiency program implementation. Sustained contact with these business partners not only improves program marketing but also the likelihood that high-efficiency natural gas equipment will be regularly stocked rather than special ordered. Also, the service provider or the retail salesperson has the ability to influence consumer purchases at the point of sale and can help increase participation in the efficiency program. Many respondents emphasized the importance of maintaining relationships and ongoing communications with service providers and appliance retailers as key to successful program implementation. Good relationships with vendors also allow program administrators to monitor their advertising practices and safeguard the accuracy of their messaging, thereby ensuring that they positively represent the utility.

Efficiency programs are also contractor-driven, and thus it is essential to develop networks of trained local contractors that are incentivized and aware of program offerings and have the expertise to complete quality installations. Quality technical training is crucial to optimizing efficiency installations and promulgating safety standards. Many programs continue to invest in education and quality training for contractors, foremost to ensure safety and quality, and also because contractors continue to prove to be effective in generating leads and in positioning the utility program as a value added to the community. In fact, some programs acknowledged the need to strengthen this area by instituting new practices to ensure that installations are sound. Among the adopted measures are authorized contractor lists, new rules or standards, additional quality assessments or quality controls, and using BPI (Building Performance Institute) certifications as a basis for awarding rebates. Others have BPI certified auditors on staff.

Low Income Programs: Program administrators encountered a few challenges with their low income programs. The non-profit agencies that administer these programs relayed that a lack of matching funds and the rules associated with those matching funds limit their implementation of the program and their reach to the low income community. They also report that they need more health and safety funding per home. In other cases, utility program administrators implement programs aimed to increase affordability, particularly for moderate income customers that are ineligible to participate in the low income efficiency program. However, since a large percentage of moderate income participants are also enrolled in the utility Customer Assistance Program—which allows them to pay their bills on a slide scale based on income rather than on total consumption—the program does not yield a meaningful affordability ratio. Nevertheless, working with community action agencies and other non-profits and leveraging fund is generally deemed as a valuable and successful component of the low income program.

Based on lessons learned, here are other best practice tips shared by respondents:

- Establish program assumptions and budgets prior to implementation, thus creating a stable operating environment for the utility and certainty of program availability in the market. It is critical to maintain budget flexibility to react to market conditions.
- Engage business partners at the very onset of program implementation.
- Aim for simplicity in program design: simple but meaningful.
- Ensure that programs are developed to meet the needs of all customer classes.
- The utility has a direct relationship with their customers and knows the market in which it operates. Program implementers should have the flexibility to be responsive to customer needs and promptly adapt to market changes—that is, they should be able to alter program features within the program implementation year by for example adding new programs or technology offerings. ARRA funding serves as an example in transforming the energy efficiency "landscape," whether on influx side funding or on the depletion side.
- Customers rely on their utility to provide unbiased solutions and advise to meet their energy needs. They demand energy-based, rather than fuel-based, efficiency solutions. Through this strategy customer needs are met, results optimized, and program efficiencies realized.
- As measures are added to a program, cross reference to other programs to ensure consistency and ascertain that program rules are enforceable and measurable (e.g., pre- and post blower door testing for residential programs).
- Develop partnerships with all stakeholders. Utility collaborations can be very effective in streamlining implementation and lowering costs. Also maintain frequent contact with regulatory energy program staff, trade allies and customers.
- Develop relationships with trade allies and make the most of their capabilities. They will help you get the message out. The following steps can help achieve this:
  - maintain a close working relationship with trade allies (e.g., warm calling after mailers can be very effective)
  - collaborate with contractors and vendors to deliver your message to a wider audience
  - meet regularly with contractors
  - offer in-house training and other resources that support them in selling your program
- Address the need to control the quality of installations and ensure safety, and thus it is necessary to ascertain quality in the contractor network. This can be achieved by the following:

    - establish rules and standards for quality installation of high efficiency natural gas equipment
    - set up an authorized contractor list or network of qualified contractors
    - provide technical training and education
    - increase quality assessments/controls
    - apply contractor certifications (e.g., BPI) as a condition for awarding rebates
- Increase focus on the customer experience and customer satisfaction:
    - Simplify the rebate application and speed up rebate processing time
    - Offer incentives that respond to current market needs
    - Involve customers and the community in the energy efficiency conversation
    - Ensure installations are performed by a qualified contractor and are quality-checked
- Marketing, advertising and outreach are critical for the program to gain momentum. The need for strategic messaging is very important. Some suggestions include:
    - A mix of shotgun and targeted marketing works well.
    - Do customize and target messaging to suit the diverse markets in which the utility operates, but keep it as simple as possible.
    - Commercial programs require a targeted marketing approach and take longer to ramp up than residential. Commercial customers are harder to reach and thus a more challenging goal. A variety of methods may be needed to relay information on programs available to them. Also incentives may need to be revamped to meet the needs of this customer segment.
    - Whole house programs are also challenging in terms of promotion and ramp up. Consider all avenues. Direct outreach probably yields the best results.
    - The need for proper promotion of incentive offerings is even more critical in an environment where other utility funded programs overlap the program's service territory.
    - Mass marketing through traditional media outlets may not be very effective nor is posting programs on website sufficient to building customer awareness. Direct outreach and communication to influencers is key to success (e.g., retailers, contractors, home builders, and realtors)
- Enhance program offerings for limited income customers. Higher incentives are required to enable them to install measures. Also set the poverty level requirement based on your particular low income customer base and make sure that funding levels are adequate per qualified customer. Leverage other funding and the expertise of community action agencies.
- Customer rebates and processing form a large part of many programs. The following might benefit program implementation:
    - It might be necessary to reconfigure customer rebates to meet current needs: Providing a more attractive rebate amounts may contribute to program success.
    - An easy application process is another success factor.
    - It is important to error proof application process to reduce flawed applications and increase ease of use.

- In many cases, an automated rebate process (particularly one with controls working in sync with the overall program budget) proved very successful. In other cases, keeping the rebate processing in-house, run by internal staff, reduced processing time and the number of follow-up calls from customers.

- Integrated electric and gas programs is a positive driver of customer participation and has been very successful to program delivery.

Market Penetration

Respondents were asked to assess the degree by which customers recognized and took advantage of their ratepayer funded natural gas efficiency programs. They were asked to estimate market penetration as the proportion of program participants to the potential market. The numerator in this ratio may represent the number of customer enrollments, processed rebates or online tool sign-ups and the denominator may represent the number of eligible customers or general service or firm gas customer base.

Forty programs provided either quantitative or qualitative answers, indicating that market saturation varied by program age, customer segment and program type. Based on 36 responses to this question, the median market penetration for natural gas efficiency programs was 3 percent. Saturation rates ranged from less than 0.1 percent to 50 percent.

Eight programs had a market share of less than one percent, 15 had from one to less than five percent, two achieved five to less than 10 percent, three reached ten to less than 15 percent, three gained between 15 and 25 percent, and four captured at least 25 percent of the potential market (see Table 29). The lower saturation rates generally correlated with newer programs.

Table 29

EFFICIENCY PROGRAM MARKET PENETRATION 36 PROGRAMS		
MARKET PENETRATION	PROGRAMS	PERCENTAGE
Less than 1%	8	22%
1% ≥ < 5%	15	42%
5% ≥ < 10%	2	6%
10% ≥ < 15%	3	8%
15% ≥ < 20%	3	8%
20% ≥ < 25%	1	3%
25% and greater	4	11%

Some respondents were uncertain regarding program adoption, either because programs were either too new or because data were not available. In other cases, market penetration studies were ongoing.

Most Successful Attributes

When asked about their most successful program attributes, respondents focused on specific implementation approaches, individual program components and program results. Top on the list of successful strategies for respondents were 1) alliances with trade allies, particularly qualified contractors, 2) partnerships with electric utilities, 3) low income programs and coordination with community action agencies and 4) efficiency rebates and incentives. Here is a listing of the most successful attributes of surveyed programs, beginning with the most cited aspects:

Partnerships with Other Stakeholders: Strong trade alliances are fostered in many programs through outreach, education, incentives, training, and shared goals. One program, for example, learned that the highest efficiency water heater sold in its service territory did not meet the efficiency threshold necessary to qualify for the utility's rebate program. The program worked with local retailers and succeeded in having the higher efficiency water heaters stocked in stores.

Many reported that contractors were the most successful attribute of their program. Particularly when educated about natural gas efficiency and its benefits to their businesses, they are the most effective resource to inform and persuade customers to consider high efficiency natural gas equipment and home weatherization and to take advantage of rebates and other financial incentives. Experienced contractors also provide intelligence to the utility program administrator on ways to modify the program in response to customer needs and the market. Local contractors are also able to leverage available rebates to offset conversion and retention costs to customers, which significantly increases program participation, according to respondents. In one program (which engages in continuous outreach to contractors in person and via newsletters and seminars), 1,000 unique contractors (or companies) participated in the program, as evidenced through rebates submitted by their customers. Contractors were also cited by several respondents as key to driving the HVAC, audit and weatherization programs.

As mentioned earlier in this report, many programs benefit from joining forces with other utilities in adjacent or overlapping service territories, in many instances combining or matching natural gas, electric and water saving measures, thereby reducing administrative costs, improving process efficiency, and benefiting customers through more comprehensive program offerings and enhanced financial incentives. For example, one gas utility enhanced rebate levels and the success rate of its Home Performance with Energy Star Program (HPWES) by partnering with its sister electric utility. Also successful are multi-utility collaboratives, such as the GasNetworks partnership, which offers nationally-recognized, comprehensive and consistent market transformation programs to customers in New England states. A large number of respondents cited gas-electric collaboration on program implementation or delivery as an important factor to the success of their programs.

Low-Income Usage Programs and Community Action Agencies (CAC): Involvement in community-level grassroots conservation efforts has also been productive—particularly coalitions with community action agencies that deliver home heating assistance and weatherization services to low-income households. Such ties help to leverage utility low-income energy efficiency program dollars with federal low-income heating assistance program (LIHEAP) funds, Department of Energy weatherization assistance funds (WAP), and utility customer assistance program funds. Such arrangements, according to many respondents, improve the ease of implementing such programs, particular when the CAC delivers weatherization services.

Low-income weatherization programs provide many economic and societal benefits, including customer comfort, safety, and cost savings for both the utility and its customer base. For many programs, the low-income weatherization component is the most successful in achieving high energy savings. Another way of coordinating among programs is when higher usage customers are identified via the customer assistance program and those most in need are provided with furnace repairs or replacements. With decreased energy usage, low income programs eventually lower the rates for the entire customer base, since all customers pay for the Customer Assistance Program. All this presents a win-win for customer and utility, as it alleviates the energy burden and improves the health and safety of low income customers, while minimizing utility bill payment arrears and write-offs and thus reducing the utility's uncollectible expenses.

Commercial and Residential Rebates and Incentives: Without direct rebates and other financial incentives, such as efficiency project subsidies and efficiency financing, many customers would be reluctant to move forward with efficiency improvements, particularly in the lingering economic climate. Many programs reported a steady growth in residential high-efficiency equipment rebate programs. In several programs, the level of interest in residential appliance incentives was very high—particularly in high efficiency furnaces (e.g., 95% AFUE condensing furnace), enhanced HVAC rebates, HPWES new construction, tank and tankless water heaters, and insulation rebates (especially attic, although in some northwestern territories where homes were already well insulated, the furnace rebates were much better received). In some residential prescriptive programs, participation exceeded first-year targets. Also successful were multi-family direct install programs and moderate income programs.

Residential and Commercial Audits and Customized Retrofits of Large Facilities: Home and business energy audits provide an educational opportunity for customers to learn about energy efficiency, improved natural gas efficiency measures, and cost savings through lower bills. Many programs offer free or low cost energy audits to encourage a whole house approach to energy efficiency. Several credit home energy audits, at least in part, to the success of their programs, although a few find that while the ultimate benefits are real, the in-home energy audit adds a degree of constraint to program implementation. For business customers, audit information gives them the opportunity to create an energy plan that incorporates recommendations from the technical assessment and seek approval for initiating energy efficiency improvements. Some credit small business outreach programs for improving market penetration. However, other programs are struggling to reach and grow this segment, particularly in the current economy.

Energy Assessments and a Whole House or Project Approach to Efficiency – Home audits, particularly when coupled with a comprehensive view of efficiency, yield very favorable results. Several programs reported a whole project or system approach to efficiency and a thorough cost-effectiveness assessment of proposed measures. According to respondents, whole house efficiency treatment yields much higher savings, compared to prescriptive measures, and increases the number of homes reached per year.

Some programs require a home energy audit to identify energy savings opportunities in the home or building shell. Others maintain contact with customers after diagnostics to encourage them to proceed with recommended seal-ups and connect them with BPI-accredited contractors qualified to carry out Tier III seal-ups. As mentioned elsewhere, other programs condition substantial furnace and other equipment rebates on completing free energy audits, again with the goal of shifting customers to a whole house approach. Other programs provide larger incentives to higher use residential customers to help them achieve the type of savings traditionally seen in low-income customer weatherization programs. Still others subsidize a portion of the recommended measures, including insulation and air duct sealing.

Successful Programs and Products: Specific products and program activities were mentioned as most successful. These include:

- Low income program continues to generate high savings by significantly lowering consumption within this traditionally high energy-usage customer segment. Positive attributes of these programs include:
  - increased safety and comfort of residents
  - weatherization as delivered by community action and other state agencies, facilitating implementation, lowering program costs and increasing participation
  - achieving high savings (averaging 24 percent decrease in natural gas consumption per residence, according to one program)
- Programs that assist moderate income residential customers who are not eligible for free weatherization services
- Steam traps have developed into an important energy efficiency element in the commercial/industrial sector.
- High efficiency furnaces were often cited: Customers are installing 95% AFUE furnaces at a higher rate than previous years. In 2010, 75% of the furnaces installed were 95% AFUE or above compared to 86% in 2011. (Other products are listed above).
- Residential efficiency retrofit and equipment financing options (especially coupled with cash incentives, including zero interest or low interest, long-term financing, and on bill repayment. On bill repayment was reported to be very successful, with often no out of pocket money required from customers.

Other Success Factors: The obvious success metric is meeting or exceeding state-mandated program savings goals, and while cost-effectiveness is a significant issue, most programs are achieving success. Additional elements that are important to the outcome of the natural gas efficiency program include:

- Expedited program startup and a renewed ability to market the natural gas advantage, for example through multi-media marketing, such as web-based applications, brochures and TV and radio advertising. However, more effective, according to several survey respondents, is direct outreach to and communication with customers, manufacturers, retailers, contractors, and the community.
- Unambiguous regulator support as evidenced through approved program cost recovery, lost revenue recovery, and utility financial incentives or performance bonuses for meeting or exceeding program goals.
- Comprehensive market transformation programs, accessible to a wide swath of customers and covering a wide range natural gas end uses
- Portfolio approach to energy efficiency programs and overall commitment to program growth and adaptability
- Program longevity across decades: Maintaining customer interest via consistent yet evolving and innovative programs
- Leveraging of statewide efficiency programs with complementary products and enhanced incentives
- Financial enablers in place to continue to motivate and drive excellence in DSM performance

- Experimenting with different approaches to increasing awareness and building support for efficiency
- Community education and outreach via various methods was very successful in driving program participation and general conservation awareness among customers. This involves reaching customers through environmental organizations, local community groups, stakeholder and partner organizations, and schools. In-person interactions with customers are also important to program success. While many programs outsource this function to a third-party, some allow their employees to engage in community education to great success and satisfaction for utility staff and customers.
- Increased customer awareness and satisfaction, via:
  - Dedicated outreach and education, community-based programs and building on a relationship that promotes trust and creates a partnership with the customer
  - A flexible program, responsive program to market changes and customer needs
  - Reliable and accurate information relayed by the utility, vendors and other trade partners
  - Growth in program recognition as a value added to the community and a resource to help residential and commercial customers save resources
  - Ensuring customer comfort while lowering their energy bills (especially for low income)
  - A simple rebate process and quick turnaround in honoring rebates (e.g., online applications, point-of-sale rebates, and program-specific processing best practice)
  - Quality installations via certified/authorized contractors
  - Ability to show energy savings compared to the customer's bill and to depict the payback period for the customer
- Streamlined and simple process for participants and trade allies, and ease of program implementation for administrators, including
  - Electronic rebate processing and verification of eligibility
  - Third-party vendor processes rebates (e.g., EFI)
  - In other cases, in-house processing worked best
- Deemed savings used to calculate energy savings

Most Innovative Features

Respondents were asked to share the most innovative features of their natural gas efficiency program. Many of the successful attributes discussed above were highlighted as innovative in some programs. These include strategic partnerships, educational and outreach efforts, energy audits and a whole system approach to efficiency, and new program offerings and approaches. Of course, what is innovative in one program might be a regular feature in other more mature programs.

Strategic Partnerships – Various collaborations were touted as both innovative and successful, including those between two neighboring utilities (e.g., gas, electric or water), multi-utility collaboratives, partnering with business on strategic program design and delivery, leveraging funds, and jointly promoting energy efficiency green products with non-energy institutions. For instance,

- Joining forces with other gas utilities to build a comprehensive energy efficiency portfolio.
- Working with electric utilities within the same or adjacent service territory was reported by several as an innovative and particularly successful, reducing costs and providing multi-fuel efficiency offerings. Integrating with electric efficiency programs provides a one-stop shop for customers, and the considerable dollar savings that are achieved can be passed along to customers through enhanced financial incentives.
- In one example—a joint high efficiency natural gas furnace with electronically commutated motor (or ECM) program—the customer receives a rebate of $400 for the installation of an electrically efficient natural gas furnace, whereby half the rebate amount is funded by the gas utility and the other half by the electric utility.
- The GasNetworks collaborative is another example of several utilities across three states.
- Business partnerships formed with industry engagement and collaboration in program design and delivery.
- Partnerships with manufacturers of furnaces and water heaters.

Targeted Marketing and Education – Many program administrators find conservation education and outreach to be a cost-effective means to achieving energy savings. Some programs have comprehensive school education programs. Others target customers directly via other means (e.g., natural gas usage letters that teach conservation and ways to lower energy bills, energy analyzer tools, and complimentary energy conservation kits). Here are some examples of pro-conservation messaging:

- Fun and effective elementary school education program, including energy efficiency kits, and indirect outreach to parents.
- Another education program, where energy saving educational materials are distributed to sixth grade classrooms within service franchise, was reported as very successful.
- Customer Take Control of Your Gas Bill Dashboard feature—a program which allows customer to go online to determine the causes of increases or decreases in their gas bills.
- Digital media developed to reach a wider swath of customers has been introduced to customers that are very receptive to this medium of communication.
- Behavioral based home energy reports.

Specific Programs

- Commercial Direct Install Program: Administrator boosted commercial customer participation by offering a no cost installation of water heating saving measures, which presents the opportunity to gain access to the customer to discuss other energy saving programs.
- Business Custom Program: Allows larger users of natural gas to implement natural gas savings measures without the restriction of prescriptive only measures.
- Large Customer Program: Account managers proactively work with large commercial customers on new energy efficient improvements and with newer customers programs, a “hold-your-hand” approach is adopted throughout the process, resulting in more completed projects and higher savings, benefiting customer and utility. It is noted that these customers have a limited market and life span

- Reservation Program: Commercial and industrial customers are required to make a reservation for rebate money applied toward high efficiency heating systems (boilers and furnaces) and water heating equipment (indirect, storage and on-demand) prior to installation and must conform to specific guidelines, such as employing a licensed contractor/or plumber for the job. Also equipment must meet or exceed Energy Star specifications, and installations may be subject to verification of operational status.
- Performance Contracting Program: Energy-efficiency with no out-of-pocket capital expense and guaranteed savings.
- Whole House Program in a rural footprint, implemented in a streamlined manner by the utility.
- Multi-Unit Market Transformation Program
- Custom component for residential RS buildings that include commercial components in order to better capture the multifamily sector
- Home Performance Solutions Program: Offers an "assisted" version of the residential home performance program to customers with 80 percent or less Area Median Income (AMI) and above 150 percent of the Federal Poverty Guideline (FPG). This program is designed for customers with incomes that are too high to be eligible for the low-income program yet too low to afford them the out of pocket expenses that non-assisted customers pay. In this program "assisted" customers pay 10 percent of the cost of qualified energy efficiency improvements. The program was able to complete almost double the planned number of audits by the end of the program year.
- Low Income Program: In this program, the utility pays 90 percent of the cost, not to exceed $4,000 and offer $440 per home on average for health and safety. Several programs offer similarly generous coverage.

New Approaches to Program Offerings

- Fuel conversion: Able to get electric to natural gas conversion rebates approved by the regulator.
- Full Fuel Cycle Energy Savings: Also successful in gaining regulator-approval to claim full fuel cycle energy savings.
- Financing Options:
    - Nimble response to changing market (including low natural gas prices) by offering long-term low-interest financing (up to 10 years), helping customers realize positive cash flow on home energy retrofit projects.
    - Shared Savings Program — Low cost financing program also designed to maintain a positive cash flow.
    - 0% financing "buy-down" dollars for whole house programs in partnership with the statewide energy efficiency program enabled utility to significantly exceed program participation and savings goals.
    - On Bill Repayment: Several introduced on-bill repayment and cited it as very successful, and particularly on bill financing that incorporates gas and electric energy efficiency measures for residential participants.
- Requirement to accept Home Performance with Energy Star audit to access incremental rebates.
- On-staff BPI certified auditors to perform in-house audits.

- Tiered appliance rebates for residential and commercial customers, providing higher incentives for more efficient equipment (e.g., Two and Three-tiered rebates for New Home Construction)
- Rebates for Annual Heating System Maintenance
- Pre-bates: Upfront rebates for audit-recommended installed measures for *moderate* income program.

Measures and Products

- Infrared cameras used to inspect certain completed installation jobs.
- Natural gas vehicle (NGV) rebates
- New clothes dryer program
- High Efficiency ECM Furnace Program
- Smart Low-flow Showerheads with Thermo Actuated Valve: Slows hot water flow to a trickle until the bypass valve is pulled, thus reducing wasted hot water and thus saving both natural gas and water.
- Pre-rinse spray valve direct install program for small commercial customers, providing them with energy savings and enabling the program implementer to survey their natural gas appliances while on site.
- Free programmable thermostats

Other Innovative Features – Programs also featured the following components as beneficial:

- Commitment to research and development of new and alternative technologies.
- Use of an annual balancing adjustment to true up program.
- Internally developed cost-effectiveness model
- Customized performance-tracking systems
- Rebates specific to moderate income customers that do not meet the poverty threshold to qualify for more traditional low- and no-cost weatherization and efficiency programs.
- Regulator's progressive leadership role and involvement in conservation programs, particularly with respect to energy efficiency options and assistance for low income customers.

APPENDIX A –ENERGY EFFICIENCY PROGRAM PROVISIONS AND PRACTICES BY STATE

STATE	Active EE Program(s)	EE Market Potential Studies	Utility Funding Requirement	Low-Income EE Requirement	Program Cost Recovery	Lost Margin Recovery	Performance-Based Incentives	Fuel Switching	Full Cycle EE Measurement	EM&V Reporting Requirement
AL										
AK										
AR	●		●		●	●	●			●
AZ	●		●	●	●	●	●		●	●
CA	●	●	●	●	●	●	●	●		●
CO	●	●	●	●	●	●	●	●	●	●
CT	●	●	●	●	●	●			●	●
DC										
DE										
FL	●		●		●	●		●	●	●
GA										
HI										
IA	●	●	●	●	●					●
ID	●		●	●	●			●		●
IL	●	●	●	●	●	●			●	●
IN	●			●	●	●		●	●	●
KS										
KY	●		●		●	●	●			●
LA										
MA	●	●	●	●	●	●	●	●		●
MD	●				●	●				●
ME	●			●	●					●
MI	●		●	●	●	●	●			●
MN	●	●	●	●	●	●	●		●	●
MO	●		●	●	●	●	●			●
MS										
MT	●					●				●
NC	●				●	●				●
ND	●				●				●	●
NE										
NH	●	●	●	●	●	●	●			●
NJ	●	●	●	●	●	●	●	●		●
NM	●		●	●	●					●
NV	●		●		●	●				●
NY	●	●	●	●	●	●	●	●		●
OH	●	●	●	●	●	●				●
OK	●		●	●	●	●	●	●	●	●
OR	●	●	●	●	●	●				●
PA	●	●	●	●	●	●		●		●
RI	●		●	●	●	●	●			●
SC	●				●	●				●
SD	●				●		●	●		●
TN										
TX	●				●			●		●
UT	●	●		●	●	●				●
VA	●			●	●	●	●	●		●
VT	●			●	●	●		●		●
WA	●	●	●	●	●	●	●	●		●
WI	●	●	●	●	●		●			●
WV										
WY	●				●	●				●
Canada	6	2	3	2	3	3	3	1	0	3
States	39	16	26	27	38	31	18	15	9	39

● In place as of 2011

Appendix B – Natural Gas Efficiency Program 2011 Expenditures and 2012 Budgets by State

STATE	A. RESIDENTIAL		B. LOW INCOME		C. COMMERCIAL		D. INDUSTRIAL		E. OTHER		F. EM&V		PROGRAMS TOTAL	
	2011 Expenditure	2012 Budget	2011 Expenditure	2012 Budget	2011 Expenditure	2012 Budget	2011 Expenditure	2012 Budget	2011 Expenditure	2012 Budget	2011 Expenditur	2012 Budget	2011 Expenditures	2012 Budget
ALABAMA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALASKA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ARIZONA	$2,266,157	$3,245,144	$402,776	$856,000	$474,412	$2,694,545	$0	$0	$ 122,612	$0	$ 34,492	$0	$3,300,449	$6,795,689
ARKANSAS	$2,154,176	$4,780,092	$0	$0	$760,694	$2,180,615	$1,333,303	$1,881,967	$90,456	$140,198	$129,662	$239,224	$4,468,291	$9,222,096
CALIFORNIA	$44,460,849	$56,554,366	$68,267,499	$61,176,047	$46,274,126	$52,953,696	$32,139,178	$38,790,915	$25,487,317	$46,828,259	$2,714,835	$7,386,200	$219,343,804	$263,689,483
COLORADO	$10,465,583	$7,358,584	$4,625,941	$4,167,145	$2,515,456	$2,195,930	$0	$5,000	$2,209,202	$1,940,121	$320,847	$404,598	$20,137,029	$16,071,378
CONNECTICUT	$6,291,259	$10,589,035	$5,051,766	$6,739,317	$6,771,186	$13,583,684	$620,005	$1,063,703	$309,935	$875,250	$335,660	$1,353,000	$19,379,811	$34,203,989
DELAWARE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
D.C.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FLORIDA	$12,238,332	$12,071,750	$0	$0	$431,465	$659,350	$0	$0	$1,619,419	$2,002,156	$15,000	$150,000	$14,304,216	$14,883,256
GEORGIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
IDAHO	$852,221	$711,824	$228,419	$242,849	$382,756	$645,968	$0	$0	$328,123	$161,843	$204,643	$87,943	$1,996,162	$1,850,427
ILLINOIS	$20,318,321	$35,952,813	$3,406,525	$14,318,397	$8,323,551	$38,562,065	$1,215,721	$5,404,043	$11,618,365	$23,235,552	$1,171,711	$2,748,954	$46,054,194	$120,221,824
INDIANA	$7,612,443	$8,939,213	$1,129,703	$1,640,338	$1,554,523	$1,807,296	$0	$0	$2,266,431	$4,957,593	$213,030	$390,711	$12,776,130	$17,735,151
IOWA	$24,182,084	$27,210,948	$7,875,696	$5,713,710	$9,090,419	$10,080,180	$0	$0	$1,965,380	$3,110,106	$162,349	$0	$43,275,928	$46,114,944
KANSAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
KENTUCKY	$1,276,458	$1,620,653	$493,894	$1,183,620	$0	$327,991	$0	$0	$7,956	$20,000	$710	$1,000	$1,779,018	$3,153,264
LOUSIANA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MAINE	$389,306	$162,393	$66,372	$90,360	$298,030	$567,151	$0	$0	$0	$0	$0	$0	$753,708	$819,904
MARYLAND	$6,400,000	$7,000,000	$3,618,501	$4,890,000	$0	$0	$0	$0	$0	$0	$20,000	$300,000	$10,038,501	$12,190,000
MASSACHUSETTS	$51,761,052	$63,975,819	$18,561,315	$27,612,089	$22,511,995	$32,929,131	$0	$0	$8,366	$5,262	$2,980,547	$5,165,244	$95,823,275	$129,687,545
MICHIGAN	$38,555,309	$35,150,963	$14,871,947	$16,330,946	$10,132,297	$13,583,799	$1,334,315	$1,631,700	$6,550,220	$8,802,341	$1,918,493	$3,694,919	$73,362,580	$79,194,668
MINNESOTA	$21,108,319	$24,400,989	$4,140,115	$5,003,339	$6,542,295	$13,862,449	$4,866,894	$3,714,659	$3,613,518	$4,037,481	$0	$0	$40,271,141	$51,018,917
MISSISSIPPI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MISSOURI	$3,669,236	$4,453,167	$1,055,000	$1,055,000	$564,292	$937,740	$0	$0	$248,194	$1,104,459	$108,092	$249,000	$5,644,814	$7,799,366
MONTANA	$2,877,102	$164,480	$0	$2,100,000	$0	$400,000	$0	$0	$0	$0	$0	$0	$2,877,102	$2,664,480
NEBRASKA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NEVADA	$2,757,332	$2,922,500	$222,769	$250,000	$397,774	$1,227,500	$0	$0	$262,407	$2,136,275	$0	$0	$3,640,282	$6,536,275
NEW HAMPSHIRE	$585,948	$2,894,799	$343,223	$885,895	$1,265,954	$3,555,400	$0	$0	$0	$0	$54,571	$55,210	$2,249,696	$7,391,304
NEW JERSEY	$61,242,651	$63,994,673	$17,043,457	$22,000,000	$14,197,306	$43,768,853	$0	$0	$1,104,670	$9,638,450	$240,718	$693,330	$93,828,802	$140,095,306
NEW MEXICO	$1,012,728	$903,634	$1,433,656	$1,433,656	$620,397	$992,550	$0	$0	$0	$0	$80,962	$72,500	$3,147,743	$3,402,340
NEW YORK	$26,402,745	$66,348,946	$14,693,098	$57,867,713	$14,684,819	$24,879,585	$2,800,000	$8,081,529	$8,769,568	$14,275,051	$1,647,115	$8,314,530	$68,997,345	$179,767,354
NORTH CAROLINA	$1,103,072	$990,000	$40,000	$100,000	$0	$0	$0	$0	$75,000	$125,000	$56,928	$60,000	$1,275,000	$1,275,000
NORTH DAKOTA	$153,236	$138,260	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$153,236	$138,260
OHIO	$19,695,461	$21,545,150	$21,269,365	$23,689,209	$895,912	$1,332,379	$0	$0	$1,003,153	$1,126,559	$330,034	$429,607	$43,193,925	$48,122,904
OKLAHOMA	$4,486,143	$9,185,286	$0	$250,000	$291,143	$593,930	$105,411	$1,142,810	$84,988	$393,279	$0	$100,000	$4,967,685	$11,665,305
OREGON	$12,738,947	$16,368,900	$1,772,912	$2,209,221	$7,624,733	$8,918,254	$2,003,849	$3,349,295	$0	$0	$382,248	$514,960	$24,522,689	$31,360,630
PENNSYLVANIA	$2,956,222	$4,246,296	$11,545,064	$16,296,475	$15,390	$191,303	$0	$0	$593,203	$824,924	$49,748	$53,000	$15,159,627	$21,611,998
RHODE ISLAND	$2,074,600	$6,339,500	$522,400	$1,843,500	$1,844,400	$5,502,200	$0	$0	$0	$0	$77,000	$315,400	$4,518,400	$14,000,600
SOUTH CAROLINA	$220,182	$140,000	$100,000	$150,000	$0	$0	$0	$0	$11,502	$50,000	$12,119	$10,000	$343,803	$350,000
SOUTH DAKOTA	$1,000,420	$905,875	$0	$0	$136,997	$132,764	$0	$0	$0	$0	$19,418	$0	$1,156,835	$1,038,639
TENNESSEE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TEXAS	$1,435,509	$1,464,500	$1,888,826	$1,110,000	$100,996	$83,150	$0	$0	$307,271	$246,250	$0	$0	$3,732,602	$2,903,900
UTAH	$18,666,504	$21,817,549	$500,000	$1,229,363	$1,712,943	$3,173,059	$0	$0	$1,409,095	$2,115,020	$0	$0	$22,288,542	$28,334,991
VERMONT	$1,190,235	$1,141,396	$42,710	$81,500	$623,944	$692,955	$0	$0	$0	$0	$4,000	$100,000	$1,860,889	$2,015,851
VIRGINIA	$2,240,463	$3,678,081	$442,606	$315,000	$69,929	$315,423	$0	$0	$643,139	$859,120	$576,055	$0	$3,972,192	$5,167,624
WASHINGTON	$9,957,416	$8,648,643	$1,852,719	$1,431,299	$11,104,512	$6,796,593	$813,739	$529,199	$971,996	$38,204,545	$1,094,981	$689,011	$25,795,363	$56,299,290
WEST VIRGINIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WISCONSIN	$6,612,565	$7,738,769	$1,024,364	$1,156,578	$2,358,276	$2,552,275	$3,188,403	$4,172,387	$3,241,194	$3,653,436	$512,005	$952,500	$16,936,807	$20,225,945
WYOMING	$173,733	$459,045	$0	$0	$16,303	$350,436	$0	$0	$47,152	$76,168	$0	$0	$237,188	$885,649

APPENDIX C – NATURAL GAS EFFICIENCY PROGRAM 2011 EXPENDITURES AND 2012 BUDGETS BY REGION

REGION	A. RESIDENTIAL		B. LOW INCOME		C. COMMERCIAL		D. INDUSTRIAL		E. OTHER		F. EM&V		PROGRAMS TOTAL	
	2011 Expenditures	2012 Budget	2011 Expenditures	2012 Budget	2011 Expenditures	2012 Budget	2011 Expenditures	2012 Budget	2011 Expenditures	2012 Budget	2011 Expenditures	2012 Budget	2011 Expenditures	2012 Budget
NORTHEAST	$152,894,017	$219,692,857	$67,869,405	$133,416,849	$62,213,023	$125,670,262	$3,420,005	$9,145,232	$10,785,742	$25,618,937	$5,389,359	$16,049,714	$302,571,552	$529,593,851
MIDWEST	$142,907,394	$166,436,147	$54,772,715	$68,907,517	$39,598,562	$82,850,947	$10,605,333	$14,922,789	$30,506,455	$50,027,527	$4,435,132	$8,465,691	$282,825,590	$391,610,618
SOUTH	$31,554,335	$ 40,930,362	$6,583,827	$7,998,620	$1,654,227	$4,160,459	$1,438,714	$3,024,777	$2,839,731	$3,836,003	$810,474	$860,224	$44,881,308	$60,810,445
WEST	$106,228,572	$119,154,669	$79,306,691	$75,095,580	$71,123,412	$80,348,531	$34,956,766	$42,674,409	$30,837,904	$91,462,231	$4,833,008	$9,155,212	$327,286,353	$417,890,632
CANADA	$14,835,713	$18,407,939	$12,358,114	$18,114,796	$32,646,407	$39,945,570	$14,791,152	$12,999,239	$27,597,283	$26,937,070	$1,414,814	$1,674,032	$103,643,482	$118,078,645
UNITED STATES	$433,584,318	$546,214,035	$208,532,637	$285,418,566	$174,589,224	$293,030,199	$50,420,818	$69,767,207	$74,969,832	$170,944,698	$15,467,972	$34,530,841	$957,564,802	$1,399,905,546
N. AMERICA	$448,420,031	$564,621,974	$220,890,751	$303,533,362	$207,235,631	$332,975,769	$65,211,970	$82,766,446	$102,567,115	$197,881,768	$16,882,786	$36,204,873	$1,061,208,285	$1,517,984,192

APPENDIX D – NATURAL GAS EFFICIENCY PROGRAM SAVINGS IMPACTS BY REGION

REGION	RESIDENTIAL	LOW INCOME	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL THERM	TRILLION BTU
NORTHEAST	77,432,261	23,314,636	104,868,672	4,070,550	17,323,362	227,009,482	22.7
MIDWEST	168,923,313	20,827,647	200,652,211	102,841,493	36,596,771	529,841,435	52.9
SOUTH	6,258,033	641,712	1,047,097	518,717	21,317	8,486,876	0.8
WEST	113,047,191	19,069,639	111,579,314	192,147,034	50,997,184	486,840,361	48.7
CANADA	129,813,782	2,486,338	159,565,177	142,622,531	351,634,753	786,122,582	78.6
UNITED STATES	365,660,799	63,853,634	418,147,294	299,577,793	104,938,634	1,252,178,154	125.2
NORTH AMERICA	495,474,581	66,339,972	577,712,471	442,200,325	456,573,387	2,038,300,736	203.7

Appendix E – Survey Participant Companies

Company	State or Province	Company	State or Province
Ameren Illinois Utilities (Ameren Corporation)	IL	FortisBC Energy Utilities	BC
Atmos Energy – Colorado	CO	Gaz Metro	QC
Atmos Energy – Iowa	IA	Great Plains Natural Gas Co (MDU Resources Group)	MN
Atmos Energy – Kentucky	KY	Intermountain Gas Company - (MDU Resources Group) - Idaho	ID
Atmos Energy - Mid Texas Division	TX	Interstate Power and Light Company (An Alliant Energy Company) - Iowa	IA
Atmos Energy – Missouri	MO	Interstate Power and Light Company (An Alliant Energy Company) - Minnesota	MN
Atmos Energy - West Texas Division	TX	LaClede Gas Company (The LaClede Group Inc.)	MO
Avista Utilities (Avista Corp.) - Idaho	ID	Madison Gas and Electric Company (MGE Energy)	WI
Avista Utilities (Avista Corp.) - Oregon	OR	Manitoba Hydro	MB
Avista Utilities (Avista Corp.) - Washington	WA	Michigan Gas Utilities Corporation (Integrys Energy Group)	MI
Baltimore Gas and Electric Corporation (Exelon Corp)	MD	MidAmerican Energy Company - Illinois	IL
Berkshire Gas Company, The (UIL Holdings Corp)	MA	MidAmerican Energy Company - Iowa	IA
Black Hills Energy – Iowa	IA	MidAmerican Energy Company - South Dakota	SD
Black Hills Energy/Colorado Gas	CO	Midwest Natural Gas Corp.	WI
California Energy Commission	CA	Minnesota Energy Resources Corporation (Integrys Energy Group)	MN
Cascade Natural Gas Corp (MDU Resources Group) - Oregon	OR	Missouri Gas Energy (Southern Union Company)	MO
Cascade Natural Gas Corp (MDU Resources Group) - Washington	WA	Montana-Dakota Utilities Co (MDU Resources Group) - Montana	MT
CenterPoint Energy - Arkansas	AR	Montana-Dakota Utilities Co (MDU Resources Group) - South Dakota	SD
CenterPoint Energy - Minnesota	MN	National Fuel Gas Distribution Corporation (National Fuel Gas Company)	NY
CenterPoint Energy - Oklahoma	OK	National Grid - Downstate Long Island	NY
Central Florida Gas Company (Div. Chesapeake Utilities Corp.)	FL	National Grid - Massachusetts	MA
Central Hudson Gas & Electric Corporation	NY	National Grid - New Hampshire	NH
Cheyenne Light, Fuel & Power Company (Black Hills Corp) - Wyoming	WY	National Grid - New York City Downstate	NY
Citizens Energy Group	IN	National Grid - New York Upstate	NY
City Gas Company	WI	National Grid - Rhode Island	RI
City of Palo Alto	CA	New Jersey Board of Public Utilities (for New Jersey Clean Energy Program)	NJ
City Utilities of Springfield	MO	New Jersey Natural Gas Company (New Jersey Resources)	NJ
Colorado Natural Gas, Inc. (Summit Energy)	CO	New Mexico Gas Company (Continenal Energy Systems LLC)	NM
Columbia Gas of Kentucky (NiSource Inc.)	KY	New York State Electric & Gas (Iberdrola USA)	NY
Columbia Gas of Maryland (NiSource Inc.)	MD	New York State Energy Research and Development Authority (NYSERDA)	NY
Columbia Gas of Massachusetts (NiSource Inc.)	MA	Nicor Gas (AGL Resources Inc.)	IL
Columbia Gas of Ohio (NiSource Inc.)	OH	North Shore Gas (Integrys Energy Group, Inc.)	IL
Columbia Gas of Pennsylvania (NiSource Inc.)	PA	Northern Indiana Public Service Company (NiSource Inc.)	IN
Columbia Gas of Virginia (NiSource Inc.)	VA	Northern Utilities D/B/A Unitil - Maine	ME
Connecticut Natural Gas Corp (UIL Holdings Corp)	CT	Northern Utilities D/B/A Unitil - New Hampshire	NH
Consolidated Edison Company of New York (Consolidated Edison, Inc.)	NY	NorthWestern Energy	MT
Consumers Energy (CMS Energy Corporation)	MI	NSTAR Electric & Gas Corporation	MA
Corning Natural Gas	NY	NW Natural - Oregon	OR
Delta Natural Gas Company, Inc. - Kentucky	KY	NW Natural - Washington	WA
Dominion East Ohio (Dominion Resources, Inc.)	OH	Oklahoma Natural Gas (Div. ONEOK, Inc.)	OK
Duke Energy Corporation - Kentucky	KY	Orange & Rockland Utilities, Inc. (Consolidated Edison Inc.)	NY
Duke Energy Corporation - Ohio	OH	Pacific Gas and Electric Company (PG&E Corporation)	CA
Elizabethtown Gas (AGL Resources Inc.)	NJ	PECO Energy (Exelon Corporation)	PA
Empire District Gas Company, The	MO	Peoples Gas Light & Coke Company (Integrys Energy Group, Inc.)	IL
Enbridge Gas Distribution Inc.	ON &	Peoples Natural Gas Company	PA
Enbridge St. Lawrence Gas	NY	Philadelphia Gas Works	PA
Energy Trust of Oregon	OR	Piedmont Natural Gas Company, Inc - South Carolina	SC
Equitable Gas Company LLC (EQT Corp.) - Pennsylvania	PA	Piedmont Natural Gas Company, Inc. - North Carolina	NC
Fitchburg Gas and Electric Light Company D/B/A Unitil Massachusetts	MA	Public Service Electric and Gas Company (PSEG)	NJ
Florida City Gas (AGL Resources Inc.)	FL	Puget Sound Energy (Puget Energy)	WA
Florida Public Utilities (Chesapeake Utilities Corp.)	FL	Questar Gas Company - Utah	UT

SURVEY PARTICIPANT COMPANIES (CONTINUED)

OMPANY - CONTINUED	STATE OR PROVINCE
Questar Gas Company - Wyoming	WY
Rochester Gas & Electric (Iberdrola USA)	NY
San Diego Gas & Electric Company (SEMPRA Energy)	CA
SaskEnergy Incorporated	SK
SourceGas Arkansas	AR
SourceGas Distribution LLC - Colorado	CO
South Jersey Gas (South Jersey Industries Inc.)	NJ
Southern California Gas Company (SEMPRA Energy)	CA
Southern Connecticut Natural Gas Company (UIL Holdings Corp)	CT
Southwest Gas Corporation - Arizona	AZ
Southwest Gas Corporation - California	CA
Southwest Gas Corporation - Nevada	NV
St. Croix Valley Natural Gas Company, Inc.	WI
Superior Water, Light & Power Company (ALLETE)	WI
TECO Peoples Gas (TECO Energy, Inc.)	FL
Texas Gas Service (ONEOK, Inc.)	TX
The Michigan Consolidated Gas Company (DTE Energy Corp)	MI
UGI Central Penn Gas (UGI Corporation)	PA
UGI Gas Service (UGI Corporation)	PA
UGI Penn Natural Gas (UGI Corporation)	PA
Union Gas Limited (Spectra Energy)	ON
UNS Gas	AZ
Vectren Energy Delivery of Indiana (Vectren Corporation)	IN
Vectren Energy Delivery of Ohio (Vectren Corporation)	OH
Vermont Gas Systems, Inc. (Northern New England Energy	VT
Virginia Natural Gas (AGL Resources Inc.)	VA
Washington Gas Light Company (WGL Holdings, Inc.) - Virginia	VA
We Energies (Wisconsin Energy Group)	WI
Westfield Gas & Electric Department	MA
Wisconsin Energy Conservation Corporation (for Focus on Energy	WI
Wisconsin Power and Light, An Alliant Energy Company	WI
Wisconsin Public Service (Integrys Energy Group)	WI
Xcel Energy Inc. - Colorado	CO
Xcel Energy Inc. - Minnesota	MN
Xcel Energy Inc. - North Dakota	ND
Xcel Energy Inc. - Wisconsin	WI
Yankee Gas Service (Northeast Utilities)	CT

Attachment 61.9

SNL Energy FINANCIAL FOCUS

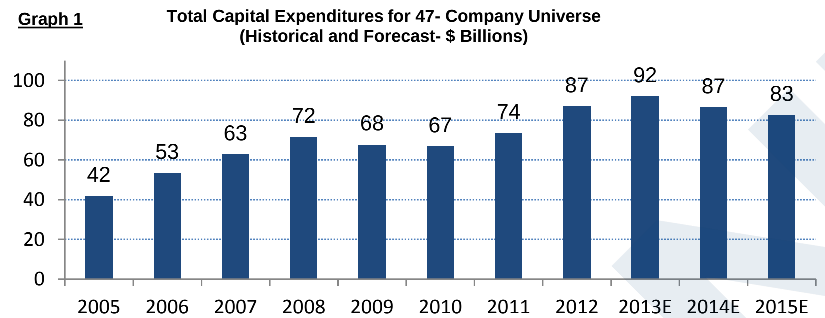
FINANCIAL FOCUS SPECIAL REPORT November 8, 2013

CAPITAL EXPENDITURE UPDATE

Spending reaching a high in 2013 and then...

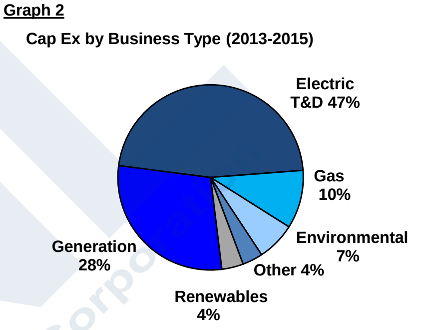
After a multiple-year period of increasing levels of spending in the power and gas sectors, capital expenditures throughout most facets of the industry, while still robust, are currently projected to fall modestly in 2014 and 2015. Much of the new investments throughout the utility industry have been driven by: the need to replace an aging generation fleet; infrastructure upgrades to the transmission and distribution (T&D) systems; coal-to-gas switching prompted by the economics of natural gas prices; and, increasingly stringent environmental regulations. Graph 1 below displays the industry trend in recent years -- spending in 2013 is forecast to reach new all-time highs.

Graph 1



Source: SNL Energy

Graph 2



Source: SNL Energy

Based on available cap ex forecasts, spending is projected to decline after 2013, with the drop-off due largely to the completion of large generation projects and the finalized installation of environmental projects to comply with the Mercury and Air Toxins Standards (MATS) and other standards promulgated by the Environmental Protection Agency (EPA). We note that NextEra alone accounts for almost $3 billion of the projected $10 billion decline in annual spending from 2013 to 2015. Other larger-cap companies with projected 2015 budgets that are below their 2013 levels include: CenterPoint Energy, Dominion Resources, PPL Corp., Public Service Enterprise Group, Southern Company, and Xcel Energy. Conversely, several companies have higher budgets for 2015 than 2013, including AES Corp, Ameren, American Electric Power, CMS Energy, and Northeast Utilities.

While several of the tables attached to this report indicate a variety of individual company forecasts, concerns have been expressed about the possible implications of the projected overall decline in spending. Without sustained robust new investment in the sector, most specifically in the form of healthy rate base expansion at regulated utility operations, how will the industry realize earnings expansion (especially within the confines of a weak economy and only moderate customer growth, at best)? Concerns of reduced utility spending levels also stem from expectations of higher power prices a few years in the near future and the financial implications from those higher prices on consumers. In recent years, the beneficial impacts of low power prices (mostly tied to low gas prices) have served as headroom for rate increases associated with new investment. In a world of higher power prices, economic and political pressure to keep bills low will likely be a meaningful factor.

These points represent a cause for concern regarding the uncertainty of future cap ex spending levels. However, we emphasize that while spending appears to be tapering off in 2014 ($87 billion) and 2015 ($83 billion), the projected levels of expenditures have actually <u>increased</u> in those years compared to our previous report (see the May 2013 Cap Ex Update), when capital expenditures were expected to be $83 billion and $80 billion in 2014 and 2015, respectively. The higher forecast could be associated with companies' expectations to comply with carbon emissions rules or other new environmental standards at existing power plants. Additionally, renewables spending is expected to increase due to elevated Renewable Portfolio Standards (RPS), requiring companies to invest in wind, solar, and other such projects. We note that most companies provide three-year formal cap ex forecasts (at best), and our experience has been that projections in years two and three have often suggested a decline. Despite the modest projected reduction in industry-wide capital expenditures, we emphasize that considerable reasons exist for spending to remain robust.

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The Rate Case Front

With the demand for power in a slow-growth pattern, and consumers increasingly more aware of conservation opportunities, passing along the cost associated with capital investments to ratepayers will likely become more challenging. Constructive and innovative regulatory policy will be needed in order for utilities to recover operating and capital investment costs associated with both environmental compliance and reliability needs.

Table 1	Base Rate Increases					
	Electric			Gas		
	ROE %	Amount ($M)	# Cases	ROE %	Amount ($M)	# Cases
2003	10.97	313.8	12	10.99	260.1	30
2004	10.75	1,091.5	30	10.59	303.5	31
2005	10.54	1,373.7	36	10.46	458.4	34
2006	10.36	1,465.0	42	10.43	444.0	25
2007	10.36	1,401.9	46	10.24	813.4	48
2008	10.46	2,899.4	42	10.37	884.8	41
2009	10.48	4,192.3	58	10.19	475.0	37
2010	10.34	5,567.7	77	10.08	816.7	49
2011	10.22	2,853.5	56	9.92	436.3	31
2012	10.17	3,131.5	70	9.94	263.9	41
LTM 9/30/13	10.07	3,595.4	62	9.86	350.9	42
Source: RRA						

Rate case activity over the past several years has been high, particularly in the electric sector, as much of the recent investments being made are at the regulated utility level (and ultimately included in rate base). The Edison Electric Institute 2012 Financial Review points out that 68% of companies increased regulated assets as a percentage of total assets during that year. Table 1, shows that total electric base rate increases nationwide peaked at $5.6 billion in 2010 (77 decisions), four times the $1.4 billion aggregate level authorized in 2007 (46 decisions). In 2011, electric rate case activity declined significantly, with total authorized increases falling to $2.9 billion (56 decisions). However, in 2012, total electric rate activity and increases rebounded to $3.1 billion (70 decisions). For the 12-months-ended Sept. 30, 2013, electric base rate increases remained robust, as total authorized increases were $3.6 billion. In the gas sector, where considerably less investment is targeted, year-to-year fluctuations in the level of rate increases authorized have been greater than in the electric sector. In 2012, total gas base rate increases were $263.9 million (41 decisions), down from the peak in 2008 of $884.8 million (41 decisions). For the 12-months-ended Sept. 30, 2013, gas base rate increases totaled $350.9 million (42 decisions). Noteworthy in our analysis of rate case activity is the trend toward lower authorized returns on equity (ROEs). Table 1 shows that average allowed electric ROEs declined from 10.97% in 2003 to a low of 10.17% in 2012, and appears to be heading lower, with average ROE for the 12-months-ended Sept. 30, 2013 at 10.07%. During the same period, average authorized gas ROEs fell from 10.99% in 2003 to 9.94% in 2012, and declined to 9.86% for the 12-months-ended Sept. 30, 2013.

EPA rules and emissions spending

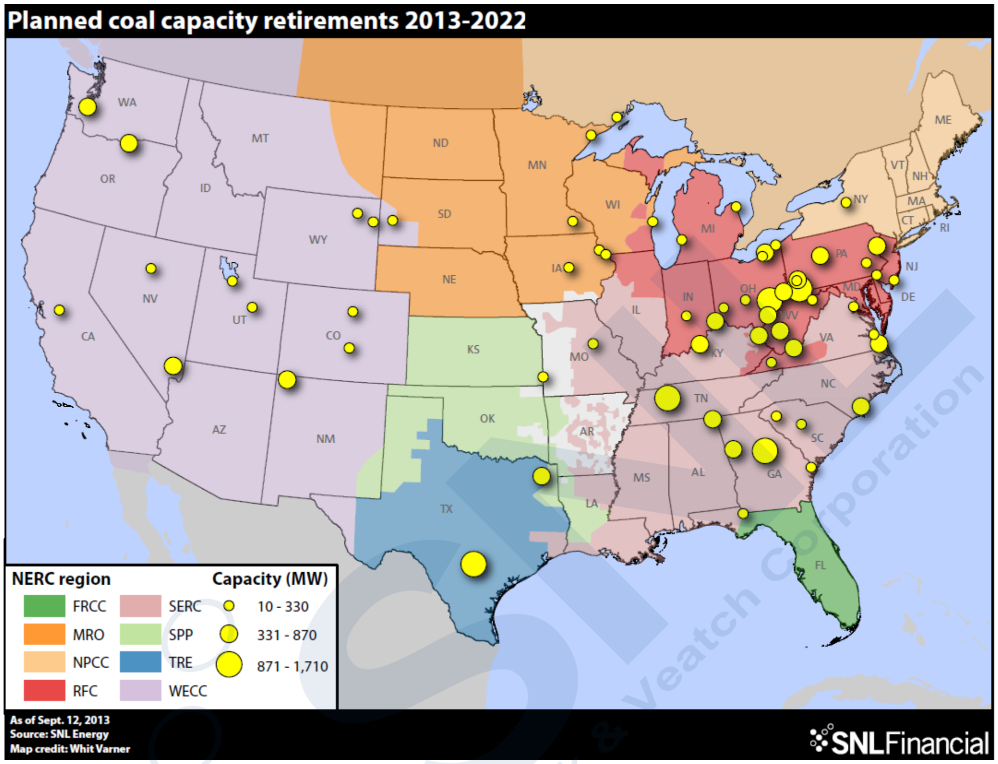
Rules proposed by and enacted by the EPA in recent years have reshaped the utility sector, as many power plants have been or will be retrofitted to comply with reduced-emissions requirements. Over the past few years, low natural gas prices have meaningfully impacted the economics of coal plant emissions plans (especially for competitive plants), prompting the shutdown of many coal-fired stations (see below). Most recently, the MATS and Cross-State Air Pollution Rule (CSAPR) have contributed to the increase in spending, as the timeline to comply with these rules have a deadline of 2015-2016. Many companies have completed or are in the process of completing the environmental upgrades required to comply with these rules. Spending on environmental upgrades by electric companies is expected to increase in 2014, but will fall by nearly 27% in 2015. However, further restrictive emissions requirements are likely to come in the future, as President Obama recently announced his Clean Air Act initiative to reduce carbon emissions from new and existing plants by 17% by 2016.

On Sept. 20, 2013, the EPA released its Proposed Carbon Pollution Standard for New Power Plants. The proposed rule would only apply to new power plants and would exclude existing generating units and power plants under construction as of Sept. 20. The rule would limit emissions from new fossil-fueled-fired plants to 1,110 lbs. of carbon dioxide (CO_2) per MWH, considerably less than the average coal plant now emits. The only fossil-fired power plants placed in service over the past few years capable of meeting the proposed rule are combined-cycle gas turbine generators, whose emission rates average about 800 lbs. per MWH. To meet these standards, new coal plants would have to capture and store much of their carbon emissions. However, much more meaningful to investors are the EPA-proposed regulations concerning the CO_2 emissions of the existing fossil fuel fleet. The current time table for the EPA to issue its proposed standards for existing power plants is June 1, 2014, with a target of June 1, 2015 for the standards to be finalized.

On Nov. 1, 2013, the EPA delayed finalizing its Cooling Water Intake Structures rule, known as section 316(b) of the Clean Water Act. The rule would require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The rule covers approximately 1,260 existing facilities; the EPA estimates that roughly 670 power plants and 590 manufacturers would be affected by the rule. The Nuclear Energy Institute has suggested that many facilities would have to retrofit cooling towers at an aggregate estimated cost of as much as $100 billion. When the final rule is effective, existing facilities would have to comply with the rule within eight years. With the implementation of 316(b) and the carbon standards for existing power plants, environmental spending should once again ramp up, reversing the forecasted trend of a decline in environmental spending in 2014 and 2015.

Due to the EPA's newly proposed rules, utilities have been forced to decide whether to make substantial capital investments in environmental upgrades or to retire plants. Many regulated utilities may choose to invest in carbon capture and sequestration technology, as these expenditures are likely to be passed on to ratepayers, whereas, merchant generators will likely continue to retire coal-fired plants, as costly retrofits may not be economical.

Coal Plant Retirements



According to a recent Data Dispatch study performed by SNL Energy, the industry plans to permanently retire nearly 28 GW of coal-fired generating capacity from August 2013 through the end of 2022. As seen on the map above and in Table 5, the ReliabilityFirst Corp (RFC) region represents a large majority of planned retirements with 13 GW, or nearly one-half of total planned coal capacity shutdowns. SNL points out that nearly 11 GW of additional coal capacity is being targeted for conversion to other fuels (of that amount as much as 4 GW may ultimately be retired). In 2012, about 9,000 MW of coal-fired generation was retired, and nearly 6,000 MW of additional capacity is projected to be retired in by the end of 2013. (See the SNL article dated Sept. 3 for more details.) Various other estimates call for coal plant closings aggregating to a range of roughly 30 GW to 60 GW (as much as 15% of the nation's generating capability), with most expected to be taken out of service over the next several years.

In 2013, FirstEnergy shut down 2,080 MW of unregulated coal-fired generation in Pennsylvania, due to uneconomic plant-emissions alterations that would have been required to comply with MATS. The coal plants shut down, including the Hatfield's Ferry plants (1,710 MW) and the Mitchell plants (370 MW), would have accounted for roughly 30% of the company's $925 million of estimated costs to comply with MATS. Additionally, Duke Energy agreed to retire five coal-fired plants (668 MW) in Indiana by 2018 under a settlement with the Sierra Club and other activist groups that also calls for the company to increase its investment in renewable energy. Duke had previously announced that it planned to shutter those plants by a 2015 deadline to comply with MATS, but the agreement specifies that Duke must complete moth-balling those plants by the 2015 deadline or — if the mercury rule is vacated or delayed before than — by June 1, 2018. Furthermore, AEP announced it will retire 500 MW of coal-fired generation at Tanners Creek 4 in Indiana by mid-2015. The company has determined that projections for limited electricity demand growth, combined with the amount of generation currently available to serve its customers, made it uneconomic to retrofit the plant.

Nonetheless, coal remains the largest energy source for electricity generation, but its share of total generation output is expected to decline from 42% in 2011 to 35% in 2040, according to the U.S. Energy Information Administration (EIA). Meanwhile, output from gas-fired generation is on the rise, and will account for more than 30% of the nation's total electric output, versus its roughly 25% historical average. Renewables contributions will also be on the rise in response to the states' renewable standards and federal tax credits for renewable generation. According to the EIA, the renewable share of total output is expected to increase from roughly 9% in 2012 to 13% in 2040.

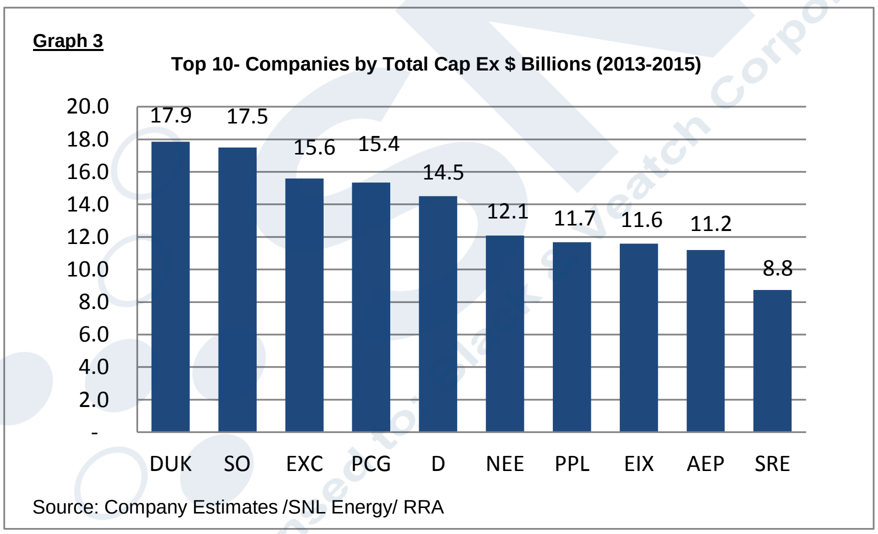
Most data in this report has been updated to include revisions to capital expenditure plans through late-October 2013. Details for the individual 47 companies are shown in Tables 2 and 3. We note that Table 3 provides a detailed analysis of industry spending, broken down by the following categories: Generation; Electric Transmission and Distribution (T&D); Environmental; Renewables; Gas Pipeline/Storage and Distribution; and, Corporate/Other.

Category identification and disclosure continue to improve since we began issuing this study in the fall-2008. However, due to an absence of uniformity in forecasting methods and details among companies in the group, coupled with limitations caused by some incomplete or limited updates, a detailed breakdown by spending category for all companies was not possible, and we have included those companies as “below the line” in Table 3.

Additionally, coincident with the absence of uniformity with respect to spending forecasts, we note that some companies employ “accrual” accounting for forecasting purposes, which may result in a timing disconnect between projections and historical data (derived from cash flow statements and therefore done on a “cash” basis). Not all companies distinguish regulated generation from competitive generation in formal forecasts; however, the vast majority of generation spending plans under way are earmarked for the regulated arena. Regarding natural gas operations, we found that very few companies provide a clear breakdown of planned spending for utility, pipeline, storage, and distribution, and we therefore group all planned gas spending into a combined gas category in Table 3.

Table 4 provides the percent change in forecasts of the 47 companies, from the projected capital expenditures for 2013 as of May 2013 (reflected in the RRA Capital Expenditure Update dated May 30, 2013) to the current forecast for 2013 as of November 2013.

The Top 10



Graph 3 displays a ranking of the 10 leading utilities in terms of planned capital expenditures over the three years 2013-2015. The majority of the companies in the top-10 list remain the same as those noted in our previous report, with the exception of Sempra Energy replacing Xcel Energy. Duke Energy remains at the top in terms of total capital expenditures, as the merger with Progress Energy increased capital expenditures substantially. Interestingly, the top-10 companies, in terms of spending, are projected to account for over 52% of total capital expenditures for the 47 companies in the RRA Index over the three years 2013-2015. Also noteworthy, is that Southern Company's capital expenditure forecast for 2013-2015 has increased by nearly $1 billion since our previous report. Southern has seen cost increases related to both plant Vogtle and plant Ratcliffe IGCC, causing an upward revision in its forecast. Finally, the California utility holding companies, Edison International, Sempra Energy, and PG&E Corp, are included in the top-10 list, as California has one of the most aggressive infrastructure spending programs in the nation, with major commitments planned for demand-side management, T&D, and generation.

Tom Serzan
Richard Ciciarelli

Table 2 Total Capital Expenditures for 47 Companies (Historical and Forecast)

	(Amount $ Millions)	2005	2006	2007	2008	2009	2010	2011	2012	2013E	2014E	2015E
										Capital Expenditure Estimate		
	ELECTRIC											
1	AES CORP.	826	1,460	2,425	2,850	2,520	2,310	2,430	2,236	1,390	1,900	1,900
2	ALLIANT ENERGY	538	399	542	879	1,203	867	673	1,158	835	860	990
3	AMEREN	935	992	1,381	1,896	1,710	1,042	1,030	1,240	1,535	1,738	1,738
4	AMERICAN ELECTRIC POWER*	2,404	3,528	3,556	3,800	2,792	2,345	2,669	3,025	3,591	3,800	3,800
5	CMS ENERGY	593	670	1,263	792	818	821	882	1,227	1,452	1,664	1,661
6	CONSOLIDATED EDISON	1,636	1,853	1,934	2,326	2,193	2,029	1,967	2,069	2,547	2,312	2,522
7	DOMINION RESOURCES	3,358	4,052	3,972	3,554	3,837	3,422	3,652	4,145	5,100	5,100	4,300
8	DTE ENERGY	1,065	1,403	1,299	1,373	1,035	1,099	1,484	1,820	2,070	2,000	1,763
9	DUKE ENERGY	2,413	3,470	3,216	4,533	4,433	4,855	4,413	5,507	6,088	5,713	6,050
10	EDISON INTERNATIONAL*	1,868	2,536	2,826	2,824	3,282	4,543	4,808	4,149	3,957	3,961	3,665
11	ENTERGY	1,458	1,633	1,578	2,212	1,931	1,974	2,040	2,675	2,367	2,094	2,191
12	EXELON CORP.	2,165	2,418	2,674	3,117	3,273	3,326	4,042	5,789	5,500	4,850	5,250
13	FIRSTENERGY*	1,208	1,315	1,633	2,888	2,203	1,963	2,278	2,678	2,380	2,632	2,493
14	NEXTERA ENERGY	2,546	3,739	5,019	5,236	6,006	5,846	6,628	9,461	5,619	3,650	2,825
15	GREAT PLAINS ENERGY	327	476	512	1,024	841	618	457	610	725	711	716
16	IDACORP INC.	193	222	287	244	252	338	338	240	235	283	308
17	HAWAIIAN ELECTRIC INDUSTRIES	224	211	218	282	289	182	235	325	380	500	600
18	NORTHEAST UTILITIES	775	872	1,115	1,255	908	954	1,077	1,472	1,590	1,674	1,734
19	NORTHWESTERN CORP.	81	101	117	125	189	228	189	219	257	246	233
20	NV ENERGY	686	986	1,197	1,536	843	629	621	499	515	444	480
21	OGE ENERGY	297	487	558	1,185	809	848	1,221	1,123	830	535	360
22	PEPCO HOLDINGS	467	475	623	643	664	802	941	1,216	1,207	1,218	1,203
23	PG&E CORP.*	1,804	2,402	2,769	3,628	3,958	3,802	4,038	4,624	5,100	5,000	5,250
24	PINNACLE WEST CAPITAL	661	738	960	936	765	748	884	890	1,094	1,030	1,190
25	PNM RESOURCES	211	321	456	345	288	281	327	309	400	478	410
26	PORTLAND GENERAL ELECTRIC	255	371	455	383	696	450	300	303	727	1,037	414
27	PPL CORP.	811	1,394	1,657	1,418	1,225	1,597	2,487	3,105	4,358	3,836	3,489
28	PUBLIC SRV. ENT. GROUP	1,053	1,015	1,348	1,771	1,794	2,160	2,083	2,574	2,540	2,170	1,640
29	SOUTHERN COMPANY	2,370	2,994	3,546	3,961	4,670	4,086	4,525	4,809	6,200	6,100	5,200
30	TECO ENERGY	295	456	494	590	640	490	454	505	520	775	562
31	UNS ENERGY CORP.	203	238	245	354	283	279	374	307	456	344	385
32	WESTAR ENERGY	213	345	748	937	556	540	697	810	892	803	642
33	WISCONSIN ENERGY	745	929	1,212	1,136	815	798	831	707	693	631	778
34	XCEL ENERGY	1,311	1,628	2,097	2,114	1,778	2,216	2,206	2,570	3,155	2,775	2,310
	Total Electric ($ Millions)	35,997	46,127	53,933	62,145	59,498	58,492	63,280	74,397	76,305	72,862	69,050
	GAS											
35	AGL RESOURCES	267	253	259	372	476	510	427	782	694	600	810
36	ATMOS ENERGY CORP.	333	425	392	472	509	543	623	733	800	800	800
37	CENTERPOINT ENERGY	693	1,007	1,114	1,020	1,160	1,509	1,303	1,212	1,614	1,423	1,173
38	INTEGRYS ENERGY	414	342	393	533	444	259	311	594	1,242	921	829
39	NISOURCE	590	627	787	1,300	777	804	1,125	1,499	2,000	1,660	1,723
40	ONEOK	250	376	884	1,473	791	583	1,336	1,866	2,676	1,909	1,917
41	PIEDMONT NATURAL GAS CO.	191	204	135	181	129	199	244	530	672	523	473
42	SCANA CORP.	385	527	725	904	914	876	884	1,077	1,422	1,630	1,511
43	SEMPRA ENERGY	1,377	1,907	2,011	2,061	1,912	2,062	2,844	2,956	3,000	2,875	2,875
44	SOUTHWEST GAS	294	345	341	300	217	215	381	396	330	335	335
45	QUESTAR CORP.	713	916	1,398	322	300	320	368	371	565	353	343
46	VECTREN CORP.	232	281	335	391	432	277	321	366	283	270	320
47	WGL HOLDINGS	113	160	165	135	139	130	202	251	368	381	359
	Total Gas ($ Millions)	5,853	7,371	8,938	9,464	8,201	8,287	10,369	12,632	15,665	13,680	13,468
	Total ($ Millions)	41,850	53,498	62,871	71,609	67,699	66,779	73,649	87,029	91,970	86,543	82,517

Source: SNL Energy, company surveys, and RRA adjustments.

Table 3

Utility Capital Expenditures by Category (2013-2017)

Companies with Segment Breakdown (Amount $ Millions)	Note	Generation 2013	Generation 2014	Generation 2015	Generation 2016	Generation 2017	% '13-'15 Total	Electric T&D*** 2013	Electric T&D*** 2014	Electric T&D*** 2015	Electric T&D*** 2016	Electric T&D*** 2017	% '13-'15 Total
Electric Companies													
ALLIANT ENERGY		92	137	86	107		12%	141	152	150	152		16%
CMS ENERGY		153	325	570	453	160	22%	399	378	372	372	417	24%
CONSOLIDATED EDISON							0%	1,555	1,603	1,742			66%
DOMINION RESOURCES	11	2,394	1,868	1,267			38%	1,419	1,433	1,248			28%
EDISON INTERNATIONAL		372	255	287	283	265	8%	3,585	3,706	3,900	3,915	3,684	97%
EXELON CORP.		2250	2125	2300			43%	2,450	2,350	2,525			47%
ENTERGY	6	1,214	915	984			47%	964	984	1,010			44%
GREAT PLAINS ENERGY	4	251	232	278			35%	266	275	302			39%
HAWAIIAN ELECTRIC INDUSTRIES	3,6	38	108	130	152	152	19%	182	240	288	336	336	48%
INTEGRYS ENERGY	6, 12	411	11	10				144	204	154			
NEXTERA ENERGY	4,6,9	2,106	1,980	1,445	1,225	1,070	46%	845	1,170	1,085	1,055	795	26%
NORTHEAST UTILITIES	1	30	30	34			2%	1,281	1,377	1,432			82%
NORTHWESTERN CORP.	6,7	109	112	104	100	133		67	64	64	64	64	
NV ENERGY		183	147	131	155	156	32%	225	170	195	215	244	41%
OGE ENERGY		100	125	75	75	75	17%	685	355	235	275	265	74%
PEPCO HOLDINGS							0%	1,033	1,056	1,064	1,003	1,073	87%
PNM RESOURCES	5, 7	131	108	114	198	308	27%	187	270	212	150	158	52%
PINNACLE WEST CAPITAL		439	334	436			36%	397	518	510			43%
PORTLAND GENERAL ELECTRIC	2, 6	332	344	159	87	36	38%	207	207	162	168	157	26%
PPL CORP.	4	966	645	667	875	993	19%	2,503	2,253	2,169	2,124	2,153	59%
PUBLIC SRV. ENT. GROUP	4	330	295	290			14%	1,900	1,605	1,150			73%
SOUTHERN COMPANY	4	3,800	3,200	2,600			55%	1,200	1,200	1,200			21%
TECO ENERGY	6, 7	190	275	189	189	189	35%	160	255	189	189	189	33%
UNS ENERGY CORP.	6	175	98	85	72	101	30%	185	131	179	124	109	42%
WESTAR ENERGY	4, 10	207	227	198			27%	342	295	331			41%
WISCONSIN ENERGY		141	151	163			22%	251	245	253			36%
XCEL ENERGY	4	775	630	560	590	715	24%	1,525	1,395	1,175	1,170	1,315	50%
Total - Electric ($ Millions)		17,188	14,675	13,162				24,098	23,891	23,296			
Gas Companies													
AGL RESOURCES													
ATMOS ENERGY CORP.	7												
CENTERPOINT ENERGY								720	677	557	534	512	33%
NISOURCE	8												
PIEDMONT NATURAL GAS CO.													
ONEOK	8												
SCANA CORP.	4	983	1,161	1,045			47%	218	216	270			10%
SOUTHWEST GAS	7												
QUESTAR CORP.	8												
WGL HOLDINGS													
Total - Gas ($ Millions)													
Companies without Segment Breakdown ("Below the line")*													
AES CORP.	8												
AMERICAN ELECTRIC POWER**		283						2,328					
AMEREN	7												
DTE ENERGY	8												
DUKE ENERGY	7												
FIRSTENERGY**	6, 8	821					11%	1,339					18%
IDACORP INC.	7												
PG&E CORP.**	7	800						3,150					
SEMPRA ENERGY	7												
VECTREN CORP.													
Total - ($ Millions)													
Grand Total ($ Millions)													

Company	Environmental 2013	Environmental 2014	Environmental 2015	Environmental 2016	Environmental 2017	% '13-'15 Total	Renewables 2013	Renewables 2014	Renewables 2015	Renewables 2016	Renewables 2017	% '13-'15 Total
Electric Companies												
ALLIANT ENERGY	355	210	200	165		28%	5	15				1%
CMS ENERGY	314	239	169	122	114	15%	85	164	9	0	0	5%
CONSOLIDATED EDISON						0%	375	95	106			8%
DOMINION RESOURCES	64	98	114			2%	73	0	0			1%
EDISON INTERNATIONAL						0%						0%
EXELON CORP.						0%	575	100	100			5%
ENTERGY						0%						0%
GREAT PLAINS ENERGY	162	149	82			18%						0%
HAWAIIAN ELECTRIC INDUSTRIES	67	58	70	82	82	13%	67	58	70	82	82	13%
INTEGRYS ENERGY	152	137	137				42	67	42			
NEXTERA ENERGY						0%	1852	220	15	5	5	17%
NORTHEAST UTILITIES	25	45	52			2%						0%
NORTHWESTERN CORP.	44	33	28	0	0							
NV ENERGY	6	30	48	15	0	6%						0%
OGE ENERGY	20	30	25	20	0	4%	10	10	10	10	10	2%
PEPCO HOLDINGS						0%	9	8	9	11	11	1%
PNM RESOURCES	10	33	20	0	0	5%	50	53	50	7	0	12%
PINNACLE WEST CAPITAL	19	71	178			8%	192	39	0			7%
PORTLAND GENERAL ELECTRIC						0%	124	422	43	4	1	27%
PPL CORP.	750	812	536	312	128	18%						0%
PUBLIC SRV. ENT. GROUP	110	105	45			4%	155	125	125			6%
SOUTHERN COMPANY	1000	1500	1100			21%						0%
TECO ENERGY	40	75	8	8	8	7%						0%
UNS ENERGY CORP.	5	23	35	50	38	5%	40	41	40	36	36	10%
WESTAR ENERGY	311	240	93			28%	4	18	0			1%
WISCONSIN ENERGY	72	0	0			3%	31	34	29			4%
XCEL ENERGY	345	235	90	15	0	8%						0%
Total - Electric ($ Millions)	3871	4123	3030				3688	1470	648			
Companies without Segment Breakdown ("Below the line")*												
AMERICAN ELECTRIC POWER**	530						358					
FIRSTENERGY**	125					2%						0%

Company	Gas Pipeline/Storage/Distribution/ and other 2013	2014	2015	2016	2017	% '13-'15 Total	Corporate / Other 2013	2014	2015	2016	2017	% '13-'15 Total
Electric Companies												
ALLIANT ENERGY	151	252	475	352		33%	92	95	80	70		10%
CMS ENERGY	407	473	460	393	321	28%	94	85	81	68	80	5%
CONSOLIDATED EDISON	507	530	578			22%	110	84	96			4%
DOMINION RESOURCES	1,108	1,662	1,630			30%	42	39	41			1%
EDISON INTERNATIONAL						0%						0%
EXELON CORP.	225	275	325			5%						0%
ENTERGY						0%	189	195	197			9%
GREAT PLAINS ENERGY						0%	46	55	53			7%
HAWAIIAN ELECTRIC INDUSTRIES						0%	27	35	42	49	49	7%
INTEGRYS ENERGY	434	446	449				59	56	37			
NEXTERA ENERGY	406	40	100	80	40	5%	410	240	180	195	190	7%
NORTHEAST UTILITIES	170	160	161			10%	84	62	55			4%
NORTHWESTERN CORP.	38	38	38	38	0							
NV ENERGY	11	10	10	10	10	2%	89	87	95	52	70	19%
OGE ENERGY						0%	15	15	15	15	15	3%
PEPCO HOLDINGS	26	28	28	28	30	2%	139	126	102	80	83	10%
PNM RESOURCES						0%	22	14	14	13	13	4%
PINNACLE WEST CAPITAL						0%	47	68	66			5%
PORTLAND GENERAL ELECTRIC						0%	64	64	50	52	48	8%
PPL CORP.						0%	139	126	117	105	99	3%
PUBLIC SRV. ENT. GROUP						0%	45	40	30			2%
SOUTHERN COMPANY						0%	200	200	300			4%
TECO ENERGY	80	100	103	103	103	15%	50	70	72	72	72	10%
UNS ENERGY CORP.	12	14	14	15	17	3%	39	38	32	37	33	9%
WESTAR ENERGY						0%	29	24	20			3%
WISCONSIN ENERGY	192	193	325			34%	6	8	8			1%
XCEL ENERGY	355	365	335	325	320	13%	155	150	150	155	150	6%
Total - Electric ($ Millions)	4,121	4,586	5,031				2,191	1,974	1,933			
Gas Companies												
CENTERPOINT ENERGY	894	746	616	593	590	39%						
SCANA CORP.	157	177	124			7%	64	76	72			3%
Companies without Segment Breakdown ("Below the line")*												
AMERICAN ELECTRIC POWER**							92					
FIRSTENERGY**						0%	95					1%
PG&E CORP.**	1,150											

Company	Total 2013	Total 2014	Total 2015	Total 2016	Total 2017	3 Year Total '13-'15
Electric Companies						
ALLIANT ENERGY	835	860	990	845		2,685
CMS ENERGY	1,452	1,664	1,661	1,408	1,092	4,777
CONSOLIDATED EDISON	2,547	2,312	2,522			7,381
DOMINION RESOURCES	5,100	5,100	4,300			14,500
EDISON INTERNATIONAL	3,957	3,961	3,665			11,583
EXELON CORP.	5,500	4,850	5,250			15,600
ENTERGY	2,367	2,094	2,191			6,652
GREAT PLAINS ENERGY	725	711	716			2,151
HAWAIIAN ELECTRIC INDUSTRIES	380	500	600	700	700	1,480
INTEGRYS ENERGY	1,242	921	829			2,992
NEXTERA ENERGY	5,619	3,650	2,825	2,560	2,100	12,094
NORTHEAST UTILITIES	1,590	1,674	1,734			4,998
NORTHWESTERN CORP.	257	246	233	201	197	736
NV ENERGY	515	444	480	448	481	1,439
OGE ENERGY	830	535	360	395	365	1,725
PEPCO HOLDINGS	1,207	1,218	1,203	1,122	1,197	3,628
PNM RESOURCES	400	478	410	368	479	1,288
PINNACLE WEST CAPITAL	1,094	1,030	1,190			3,314
PORTLAND GENERAL ELECTRIC	727	1,037	414	310	242	2,178
PPL CORP.	4,358	3,836	3,489	3,416	3,373	11,683
PUBLIC SRV. ENT. GROUP	2,540	2,170	1,640			6,350
SOUTHERN COMPANY	6,200	6,100	5,200			17,500
TECO ENERGY	520	775	562	562	562	1,857
UNS ENERGY CORP.	456	344	385	333	334	1,185
WESTAR ENERGY	892	803	642			2,338
WISCONSIN ENERGY	693	631	778			2,102
XCEL ENERGY	3,155	2,775	2,310	2,255	2,500	8,240
Total - Electric ($ Millions)	**55,158**	**50,718**	**46,578**			**152,454**
Gas Companies						
AGL RESOURCES	694	600	810			2,104
ATMOS ENERGY CORP.	800	800	800	800		2,400
CENTERPOINT ENERGY	1,614	1,423	1,173	1,127	1,102	4,210
NISOURCE	2,000	1,660	1,723			5,383
PIEDMONT NATURAL GAS CO.	672	523	473			1,668
ONEOK	2,676	1,909	1,917			6,502
SCANA CORP.	1,422	1,630	1,511			4,563
SOUTHWEST GAS	330	335	335			1,000
QUESTAR CORP.	565	353	343			1,262
WGL HOLDINGS	368	381	359	355	339	1,107
Total - Gas ($ Millions)	**11,141**	**9,614**	**9,444**			**30,199**
Companies without Segment Breakdown ("Below the line")*						
AES CORP.	1,390	1,900	1,900			5,190
AMERICAN ELECTRIC POWER**	3,591	3,800	3,800			11,191
AMEREN	1,535	1,738	1,738	1,738	1,738	5,011
DTE ENERGY	2,070	2,000	1,763			5,833
DUKE ENERGY	6,088	5,713	6,050			17,850
FIRSTENERGY**	2,380	2,632	2,493			7,505
IDACORP INC.	235	283	308			825
PG&E CORP.**	5,100	5,000	5,250	5,250		15,350
SEMPRA ENERGY	3,000	2,875	2,875	2,875	2,875	8,750
VECTREN CORP.	283	270	320			873
Total - ($ Millions)	**25,671**	**26,210**	**26,496**			**78,377**
Grand Total ($ Millions)	**91,970**	**86,543**	**82,517**			**261,030**

Source: SNL Energy, company surveys, and RRA adjustments.

Notes to Table 3:

1 RRA estimate for proportion related to environmental and/or renewable spending

2 Maintenance and growth capital expenditure apportioned to: generation 15% , T&D 65%, other 20%

3 Spending on fuel included in generation

4 Nuclear spending included in generation

5 Includes potential capital expenditures that may not be realized

6 Capital expenditures calculated and apportioned as per RRA adjustments

7 Average shown for any range provided by the company

8 FactSet estimates for years in which company has not provided data

9 Includes only capital expenditures that have been approved by NEE's board of directors

10 Includes the potential investment for the Praire Wind Transmission joint venture

11 Includes the planned construction of the Cove Point liquefacation project under gas spending

12 Includes equity contribution for the American Transmission Company

* Classification by business type unavailable for some years, resulting in "below the line" listing

** Company only provides a breakdown for 2013

*** Electric T&D includes Smart Metering/AMI

Percentages of three-year total shown next to each category

Table 4	Capital Expenditures (% Change in forecast)			
	Electric	May 2013 Forecast for 2013	Nov. 2013 Forecast for 2013	(%) change
1	AES CORP.	1380	1390	0.7%
2	ALLIANT ENERGY	835	835	0.0%
3	AMEREN	1540	1535	-0.3%
4	AMERICAN ELECTRIC POWER*	3578	3591	0.4%
5	CMS ENERGY	1374	1452	5.7%
6	CONSOLIDATED EDISON	2547	2547	0.0%
7	DOMINION RESOURCES	4682	5100	8.9%
8	DTE ENERGY	2175	2070	-4.8%
9	DUKE ENERGY	6088	6088	0.0%
10	EDISON INTERNATIONAL*	4424	3957	-10.6%
11	ENTERGY	2367	2367	0.0%
12	EXELON CORP.	5500	5500	0.0%
13	FIRSTENERGY*	2380	2380	0.0%
14	NEXTERA ENERGY	4565	5619	23.1%
15	IDACORP INC.	250	235	-6.0%
16	HAWAIIAN ELECTRIC INDUSTRIES	380	380	0.0%
17	GREAT PLAINS ENERGY	725	725	0.0%
18	NORTHEAST UTILITIES	1590	1590	0.0%
19	NORTHWESTERN CORP.	260	257	-1.1%
20	NV ENERGY	515	515	0.0%
21	OGE ENERGY	1245	830	-33.3%
22	PEPCO HOLDINGS	1207	1207	0.0%
23	PG&E CORP.*	5100	5100	0.0%
24	PINNACLE WEST CAPITAL	1121	1094	-2.4%
25	PNM RESOURCES	493	400	-18.8%
26	PORTLAND GENERAL ELECTRIC	514	727	41.4%
27	PPL CORP.	4358	4358	0.0%
28	PUBLIC SRV. ENT. GROUP	2535	2540	0.2%
29	SOUTHERN COMPANY	5600	6200	10.7%
30	TECO ENERGY	520	520	0.0%
31	UNS ENERGY CORP.	393	456	16.0%
32	WESTAR ENERGY	892	892	0.0%
33	WISCONSIN ENERGY	693	693	0.0%
34	XCEL ENERGY	3155	3155	0.0%
	Total Electric ($Millions)	**74980**	**76305**	**1.8%**
	Gas	**May 2013 Forecast for 2013**	**Nov. 2013 Forecast for 2013**	**(%) change**
35	AGL RESOURCES	700	694	-0.9%
36	ATMOS ENERGY CORP.	780	800	2.6%
37	CENTERPOINT ENERGY	1614	1614	0.0%
38	INTEGRYS ENERGY	1266	1242	-1.9%
39	NISOURCE	2000	2000	0.0%
40	ONEOK	2956	2676	-9.5%
41	PIEDMONT NATURAL GAS CO.	550	672	22.2%
42	SCANA CORP.	1639	1422	-13.2%
43	SEMPRA ENERGY	3300	3000	-9.1%
44	SOUTHWEST GAS	340	330	-2.9%
45	QUESTAR CORP.	450	565	25.6%
46	VECTREN CORP.	290	283	-2.5%
47	WGL HOLDINGS	368	368	0.0%
	Total Gas ($Millions)	**16253**	**15665**	**-3.6%**
	Total Electric and Gas ($Millions)	**91233**	**91970**	**0.8%**

Table 5 — Planned coal unit retirements 2013-2018

Unit	NERC region	State	2012 capacity factor (%)	Operating capacity (MW)	Original in-service year	Date to be retired	Age at retirement	Ultimate parent
B. L. England ST 1	RFC	NJ	6.59	113	1962	Sep 2013	51	Multi-owned
Chamois ST 1	SERC	MO	NA	17	1953	Sep 2013	60	Central Electric Power Cooperative - MO
Chamois ST 2	SERC	MO	NA	50	1960	Sep 2013	53	Central Electric Power Cooperative - MO
Syracuse Energy ST GEN1	NPCC	NY	NA	63	1991	Sep 2013	22	GDF Suez SA
Syracuse Energy ST GEN2	NPCC	NY	NA	11	2002	Sep 2013	11	GDF Suez SA
Titus ST 1	RFC	PA	4.51	81	1951	Sep 2013	62	NRG Energy Inc.
Titus ST 2	RFC	PA	4.19	81	1951	Sep 2013	62	NRG Energy Inc.
Titus ST 3	RFC	PA	4.80	81	1953	Sep 2013	60	NRG Energy Inc.
Harllee Branch ST 2	SERC	GA	11.74	325	1967	Oct 2013	46	Southern Co.
Hatfield's Ferry ST 1	RFC	PA	60.60	570	1969	Oct 2013	44	FirstEnergy Corp.
Hatfield's Ferry ST 2	RFC	PA	65.40	570	1970	Oct 2013	43	FirstEnergy Corp.
Hatfield's Ferry ST 3	RFC	PA	67.42	570	1971	Oct 2013	42	FirstEnergy Corp.
Mitchell (PA) ST 3	RFC	PA	46.51	288	1963	Oct 2013	50	FirstEnergy Corp.
Arapahoe ST 3	WECC	CO	49.56	44	1951	Dec 2013	62	Xcel Energy Inc.
Canadys ST 2	SERC	SC	44.82	115	1964	Dec 2013	49	SCANA Corp.
Canadys ST 3	SERC	SC	52.90	180	1967	Dec 2013	46	SCANA Corp.
Harllee Branch ST 1	SERC	GA	35.24	266	1965	Dec 2013	48	Southern Co.
Indian River (DE) ST 3	RFC	DE	16.05	170	1970	Dec 2013	43	NRG Energy Inc.
L V Sutton ST 1	SERC	NC	18.35	98	1954	Dec 2013	59	Duke Energy Corp.
L V Sutton ST 2	SERC	NC	15.73	107	1955	Dec 2013	58	Duke Energy Corp.
L V Sutton ST 3	SERC	NC	27.04	411	1972	Dec 2013	41	Duke Energy Corp.
W N Clark ST 1	WECC	CO	NA	18	1955	Dec 2013	58	Black Hills Corp.
W N Clark ST 2	WECC	CO	NA	25	1959	Dec 2013	54	Black Hills Corp.
Port of Stockton District Ene	WECC	CA	NA	44	1987	2013	26	DTE Energy Co.
Widows Creek ST 1	SERC	AL	0.00	113	1952	2013	61	Tennessee Valley Authority
Widows Creek ST 2	SERC	AL	0.00	113	1952	2013	61	Tennessee Valley Authority
Ben French ST1	WECC	SD	NA	22	1961	Mar 2014	53	Black Hills Corp.
Elrama ST 1	RFC	PA	NM	93	1952	Mar 2014	62	NRG Energy Inc.
Elrama ST 2	RFC	PA	0.82	93	1953	Mar 2014	61	NRG Energy Inc.
Elrama ST 3	RFC	PA	0.64	103	1954	Mar 2014	60	NRG Energy Inc.
Elrama ST 4	RFC	PA	4.14	171	1960	Mar 2014	54	NRG Energy Inc.
Neil Simpson ST 5	WECC	WY	NA	19	1969	Mar 2014	45	Black Hills Corp.
Osage (WY) ST 1	WECC	WY	NA	10	1948	Mar 2014	66	Black Hills Corp.
Osage (WY) ST 2	WECC	WY	NA	10	1949	Mar 2014	65	Black Hills Corp.
Osage (WY) ST 3	WECC	WY	NA	10	1952	Mar 2014	62	Black Hills Corp.
Portland (PA) ST 1	RFC	PA	3.17	158	1958	Jun 2014	56	NRG Energy Inc.
Portland (PA) ST 2	RFC	PA	4.79	243	1962	Jun 2014	52	NRG Energy Inc.
Salem Harbor ST 3	NPCC	MA	17.31	150	1958	Jun 2014	56	Footprint Power LLC
Dubuque ST 3	MRO	IA	NA	29	1952	Dec 2014	62	Alliant Energy Corp.
Dubuque ST 4	MRO	IA	NA	36	1959	Dec 2014	55	Alliant Energy Corp.
Lansing ST 3	MRO	IA	NM	34	1957	Dec 2014	57	Alliant Energy Corp.
North Branch (WV) CFB 1	SERC	WV	NA	77	1992	Dec 2014	22	Dominion Resources Inc.
Welsh ST 2	SPP	TX	71.50	528	1980	Dec 2014	34	American Electric Power Co. Inc.
Reid Gardner ST 1	WECC	NV	13.73	100	1965	2014	49	NV Energy Inc.
Reid Gardner ST 2	WECC	NV	6.26	100	1968	2014	46	NV Energy Inc.
Reid Gardner ST 3	WECC	NV	10.74	98	1976	2014	38	NV Energy Inc.
Widows Creek ST 3	SERC	AL	0.00	113	1952	2014	62	Tennessee Valley Authority
Widows Creek ST 4	SERC	AL	NM	113	1953	2014	61	Tennessee Valley Authority
Carbon ST 1	WECC	UT	NA	67	1954	Jan 2015	61	Multi-owned
Carbon ST 2	WECC	UT	NA	105	1957	Jan 2015	58	Multi-owned
Miami Fort ST 6	RFC	OH	62.45	163	1960	Jan 2015	55	Duke Energy Corp.
Asbury ST 2	SPP	MO	0.00	18	1986	Feb 2015	29	Empire District Electric Co.
Avon Lake ST 7	RFC	OH	3.21	96	1949	Apr 2015	66	NRG Energy Inc.
Avon Lake ST 9	RFC	OH	46.57	640	1970	Apr 2015	45	NRG Energy Inc.
Eastlake ST 1	RFC	OH	41.99	132	1953	Apr 2015	62	FirstEnergy Corp.
Eastlake ST 2	RFC	OH	35.55	132	1953	Apr 2015	62	FirstEnergy Corp.
Eastlake ST 3	RFC	OH	39.50	132	1954	Apr 2015	61	FirstEnergy Corp.
Green River ST 3	SERC	KY	NA	71	1954	Apr 2015	61	PPL Corp.
Green River ST 4	SERC	KY	NA	100	1959	Apr 2015	56	PPL Corp.
Harbor Beach ST 1	RFC	MI	NA	103	1968	Apr 2015	47	DTE Energy Co.
Harllee Branch ST 3	SERC	GA	8.36	509	1968	Apr 2015	47	Southern Co.
Harllee Branch ST 4	SERC	GA	12.73	507	1969	Apr 2015	46	Southern Co.
Lake Shore ST 18	RFC	OH	8.65	245	1962	Apr 2015	53	FirstEnergy Corp.
Scholz ST 1	SERC	FL	NA	46	1953	Apr 2015	62	Southern Co.
Scholz ST 2	SERC	FL	NA	46	1953	Apr 2015	62	Southern Co.
Shawville ST 1	RFC	PA	20.38	122	1954	Apr 2015	61	NRG Energy Inc.
Shawville ST 2	RFC	PA	24.50	125	1954	Apr 2015	61	NRG Energy Inc.
Shawville ST 3	RFC	PA	30.12	175	1959	Apr 2015	56	NRG Energy Inc.
Shawville ST 4	RFC	PA	28.36	175	1960	Apr 2015	55	NRG Energy Inc.
Wabash River ST 2	RFC	IN	27.38	85	1953	Apr 2015	62	Duke Energy Corp.
Wabash River ST 3	RFC	IN	21.45	85	1954	Apr 2015	61	Duke Energy Corp.
Wabash River ST 4	RFC	IN	28.47	85	1955	Apr 2015	60	Duke Energy Corp.
Wabash River ST 5	RFC	IN	5.44	95	1956	Apr 2015	59	Duke Energy Corp.
Walter C Beckjord ST 2	RFC	OH	NM	94	1953	Apr 2015	62	Duke Energy Corp.
Walter C Beckjord ST 3	RFC	OH	13.92	128	1954	Apr 2015	61	Duke Energy Corp.
Walter C Beckjord ST 4	RFC	OH	24.14	150	1958	Apr 2015	57	Duke Energy Corp.
Walter C Beckjord ST 5	RFC	OH	42.85	238	1962	Apr 2015	53	Duke Energy Corp.
Yates ST 1	SERC	GA	1.91	97	1950	Apr 2015	65	Southern Co.
Yates ST 2	SERC	GA	29.80	103	1950	Apr 2015	65	Southern Co.
Yates ST 3	SERC	GA	36.35	111	1952	Apr 2015	63	Southern Co.
Yates ST 4	SERC	GA	4.25	133	1957	Apr 2015	58	Southern Co.
Yates ST 5	SERC	GA	0.72	135	1958	Apr 2015	57	Southern Co.
Cane Run ST 4	SERC	KY	47.97	155	1962	May 2015	53	PPL Corp.
Cane Run ST 5	SERC	KY	62.92	168	1966	May 2015	49	PPL Corp.
Cane Run ST 6	SERC	KY	51.45	240	1969	May 2015	46	PPL Corp.

Table 5 (Cont'd) **Planned coal unit retirements 2013-2018**

Unit	NERC region	State	2012 capacity factor (%)	Operating capacity (MW)	Original in-service year	Date to be retired	Age at retirement	Ultimate parent
Deepwater (NJ) ST 6	RFC	NJ	NA	82	1954	May 2015	61	Calpine Corp.
Ashtabula ST 5	RFC	OH	11.58	244	1958	Jun 2015	57	FirstEnergy Corp.
Big Sandy ST 2	RFC	KY	27.35	800	1969	Jun 2015	46	American Electric Power Co. Inc.
Clinch River ST 3	RFC	VA	7.37	235	1961	Jun 2015	54	American Electric Power Co. Inc.
Glen Lyn ST 5	RFC	VA	1.13	95	1944	Jun 2015	71	American Electric Power Co. Inc.
Glen Lyn ST 6	RFC	VA	3.33	240	1957	Jun 2015	58	American Electric Power Co. Inc.
Kammer ST 1	RFC	WV	29.34	210	1958	Jun 2015	57	American Electric Power Co. Inc.
Kammer ST 2	RFC	WV	26.33	210	1958	Jun 2015	57	American Electric Power Co. Inc.
Kammer ST 3	RFC	WV	41.09	210	1959	Jun 2015	56	American Electric Power Co. Inc.
Kanawha River ST 1	RFC	WV	24.59	200	1953	Jun 2015	62	American Electric Power Co. Inc.
Kanawha River ST 2	RFC	WV	32.29	200	1953	Jun 2015	62	American Electric Power Co. Inc.
Muskingum River ST 1	RFC	OH	4.78	205	1953	Jun 2015	62	American Electric Power Co. Inc.
Muskingum River ST 2	RFC	OH	5.04	205	1954	Jun 2015	61	American Electric Power Co. Inc.
Muskingum River ST 3	RFC	OH	23.61	215	1957	Jun 2015	58	American Electric Power Co. Inc.
Muskingum River ST 4	RFC	OH	16.22	215	1958	Jun 2015	57	American Electric Power Co. Inc.
O H Hutchings ST 1	RFC	OH	NM	59	1948	Jun 2015	67	AES Corp.
O H Hutchings ST 2	RFC	OH	0.23	56	1949	Jun 2015	66	AES Corp.
O H Hutchings ST 3	RFC	OH	2.99	64	1950	Jun 2015	65	AES Corp.
O H Hutchings ST 5	RFC	OH	3.30	64	1952	Jun 2015	63	AES Corp.
O H Hutchings ST 6	RFC	OH	1.89	64	1953	Jun 2015	62	AES Corp.
Philip Sporn ST 1	RFC	WV	14.32	150	1950	Jun 2015	65	American Electric Power Co. Inc.
Philip Sporn ST 2	RFC	WV	36.87	150	1950	Jun 2015	65	American Electric Power Co. Inc.
Philip Sporn ST 3	RFC	WV	16.22	150	1951	Jun 2015	64	American Electric Power Co. Inc.
Philip Sporn ST 4	RFC	WV	7.53	150	1952	Jun 2015	63	American Electric Power Co. Inc.
Picway ST 5	RFC	OH	NA	100	1955	Jun 2015	60	American Electric Power Co. Inc.
Tanners Creek ST 1	RFC	IN	8.23	145	1951	Jun 2015	64	American Electric Power Co. Inc.
Tanners Creek ST 2	RFC	IN	12.42	145	1952	Jun 2015	63	American Electric Power Co. Inc.
Tanners Creek ST 3	RFC	IN	32.16	205	1954	Jun 2015	61	American Electric Power Co. Inc.
Walter C Beckjord ST 6	RFC	OH	51.31	420	1969	Jun 2015	46	Multi-owned
Widows Creek ST 5	SERC	AL	0.00	113	1954	July 2015	61	Tennessee Valley Authority
Widows Creek ST 6	SERC	AL	0.00	113	1954	July 2015	61	Tennessee Valley Authority
Edgewater (WI) ST 3	MRO	WI	3.45	72	1951	Dec 2015	64	Alliant Energy Corp.
Johnsonville (TN) ST 10	SERC	TN	12.00	144	1959	Dec 2015	56	Tennessee Valley Authority
Johnsonville (TN) ST 5	SERC	TN	32.61	113	1952	Dec 2015	63	Tennessee Valley Authority
Johnsonville (TN) ST 6	SERC	TN	26.58	113	1953	Dec 2015	62	Tennessee Valley Authority
Johnsonville (TN) ST 7	SERC	TN	3.35	144	1958	Dec 2015	57	Tennessee Valley Authority
Johnsonville (TN) ST 8	SERC	TN	4.03	144	1959	Dec 2015	56	Tennessee Valley Authority
Johnsonville (TN) ST 9	SERC	TN	18.40	144	1959	Dec 2015	56	Tennessee Valley Authority
Nelson Dewey ST 1	MRO	WI	47.48	105	1959	Dec 2015	56	Alliant Energy Corp.
Nelson Dewey ST 2	MRO	WI	44.34	106	1962	Dec 2015	53	Alliant Energy Corp.
Silver Lake (MN) ST 1	MRO	MN	NA	10	1948	Dec 2015	67	Rochester Public Utilities
Silver Lake (MN) ST 2	MRO	MN	NA	14	1953	Dec 2015	62	Rochester Public Utilities
Silver Lake (MN) ST 3	MRO	MN	NA	24	1962	Dec 2015	53	Rochester Public Utilities
Silver Lake (MN) ST 4	MRO	MN	NA	46	1969	Dec 2015	46	Rochester Public Utilities
Black Dog ST 3	MRO	MN	63.35	79	1955	2015	60	Xcel Energy Inc.
Black Dog ST 4	MRO	MN	58.73	153	1960	2015	55	Xcel Energy Inc.
Cherokee (CO) ST 3	WECC	CO	61.65	152	1962	2015	53	Xcel Energy Inc.
Chesapeake ST 3	SERC	VA	51.24	162	1959	2015	56	Dominion Resources Inc.
Chesapeake ST1	SERC	VA	14.30	111	1953	2015	62	Dominion Resources Inc.
Chesapeake ST2	SERC	VA	20.40	111	1954	2015	61	Dominion Resources Inc.
Chesapeake ST4	SERC	VA	16.43	221	1962	2015	53	Dominion Resources Inc.
Eagle Valley ST 3	RFC	IN	2.10	40	1951	2015	64	AES Corp.
Eagle Valley ST 4	RFC	IN	8.36	57	1953	2015	62	AES Corp.
Eagle Valley ST 5	RFC	IN	17.27	63	1953	2015	62	AES Corp.
Eagle Valley ST 6	RFC	IN	19.62	100	1956	2015	59	AES Corp.
Muskingum River ST 5	RFC	OH	16.75	585	1968	2015	47	American Electric Power Co. Inc.
Taconite Harbor ST GEN3	MRO	MN	53.60	82	1967	2015	48	ALLETE Inc.
W S Lee ST 1	SERC	SC	2.18	100	1951	2015	64	Duke Energy Corp.
W S Lee ST 2	SERC	SC	3.28	102	1951	2015	64	Duke Energy Corp.
Yorktown ST 1	SERC	VA	17.28	162	1957	2015	58	Dominion Resources Inc.
Yorktown ST 2	SERC	VA	28.36	165	1959	2015	56	Dominion Resources Inc.
Northeastern ST 4	SPP	OK	75.95	460	1980	Jan 2016	36	American Electric Power Co. Inc.
Kraft ST 2	SERC	GA	39.17	52	1961	Apr 2016	55	Southern Co.
Kraft ST 3	SERC	GA	30.31	101	1965	Apr 2016	51	Southern Co.
Kraft ST1	SERC	GA	42.16	48	1958	Apr 2016	58	Southern Co.
B. L. England ST 2	RFC	NJ	7.40	155	1964	May 2016	52	Multi-owned
Sutherland (IA) ST 1	MRO	IA	22.22	28	1955	Dec 2016	61	Alliant Energy Corp.
Sutherland (IA) ST 3	MRO	IA	24.31	79	1961	Dec 2016	55	Alliant Energy Corp.
Goddard Steam Plant ST 1	RFC	MD	NA	5	1957	2016	59	Naval Facilities Engineering Command
Goddard Steam Plant ST 2	RFC	MD	NA	5	1957	2016	59	Naval Facilities Engineering Command
James De Young ST 3	RFC	MI	NA	11	1951	2016	65	Holland City of
James De Young ST 4	RFC	MI	NA	21	1962	2016	54	Holland City of
James De Young ST 5	RFC	MI	NA	27	1969	2016	47	Holland City of
Johnsonville (TN) ST 1	SERC	TN	35.77	113	1951	Dec 2017	66	Tennessee Valley Authority
Johnsonville (TN) ST 2	SERC	TN	44.26	113	1951	Dec 2017	66	Tennessee Valley Authority
Johnsonville (TN) ST 3	SERC	TN	48.73	113	1952	Dec 2017	65	Tennessee Valley Authority
Johnsonville (TN) ST 4	SERC	TN	53.72	113	1952	Dec 2017	65	Tennessee Valley Authority
San Juan ST 2	WECC	NM	70.12	320	1973	Dec 2017	44	Multi-owned
San Juan ST 3	WECC	NM	63.43	495	1979	Dec 2017	38	Multi-owned
Valmont ST 5	WECC	CO	62.45	184	1964	Dec 2017	53	Xcel Energy Inc.
Cherokee (CO) ST 4	WECC	CO	64.99	352	1968	2017	49	Xcel Energy Inc.
Reid Gardner ST 4	WECC	NV	49.84	255	1983	2017	34	Multi-owned
Kennecott Utah Copper ST	WECC	UT	12.11	50	1943	Jan 2018	75	Rio Tinto
Kennecott Utah Copper ST	WECC	UT	14.43	25	1943	Jan 2018	75	Rio Tinto
Kennecott Utah Copper ST	WECC	UT	12.60	25	1946	Jan 2018	72	Rio Tinto
McMeekin ST 1	SERC	SC	20.13	125	1958	Dec 2018	60	SCANA Corp.
McMeekin ST 2	SERC	SC	32.99	125	1958	Dec 2018	60	SCANA Corp.
J T Deely ST 1	TRE	TX	36.19	435	1977	2018	41	CPS Energy
J T Deely ST 2	TRE	TX	62.21	436	1978	2018	40	CPS Energy

Includes only coal units for which the company has reported a firm retirement date between 2013 and 2018.

As of Aug. 19, 2013

Source: SNL Energy