Optimal ENERGY Integrated Energy Resources

MEMORANDUM

To: Illinois CHP Subcommittee
cc:
From: Phil Mosenthal, Chris Neme
Date:
Subject: CHP Savings Proposal

HOW CHP WORKS

Combined Heat and Power (CHP) systems improve overall efficiency by co-producing both electricity and useful thermal energy on site in a more efficient method than purchasing centrally generated electricity and purchasing fossil fuels to produce on-site thermal energy. Typical central power plants often have total system efficiencies of 30-50%.[1] In contrast, a well designed CHP system can provide an overall on-site efficiency of around 75%. This is possible because central electric power plants generally cannot make full use of the substantial thermal energy that is a by-product of power generation. Thus, in many cases they simply throw this heat away through cooling towers or other means. By siting CHP systems in facilities that can use the thermal waste heat year-round, much higher overall efficiency can be captured.

As DCEO has noted, ultimately society cares about the final upstream impacts on primary energy usage. Thus, the U.S. EPA encourages considering the entire energy stream and determining ultimate Btu savings at the source.[2] DCEO has provided some basic equations that reflects this approach:

[1] DCEO's estimated heat rates of around 10,800 imply an overall electric generation efficiency of only about 32%. However, newer combined cycle gas plants can have much higher efficiencies. To the extent gas is being saved on the margin, it is likely that this is coming from plants that are more efficient than the overall system heat rate.

[2] Fuel & Carbon Dioxide Emissions Savings Calculation Methodology for CHP Systems – US EPA CHP Partnership; August 2012

The overall efficiency of the CHP system is calculated as follows:

$$CHP\ Annual\ Eff\ (HHV) = \frac{\left[Useful\ thermal\ \left(\frac{kBtu}{yr}\right) + Useful\ electric\ \left(\frac{kWh}{yr}\right) * 3.412\ \left(\frac{kBtu}{kWh}\right)\right]}{F\ total\ CHP\ \left(\frac{kBtu}{yr}\right)}$$

Where:

- *Useful thermal energy output (kBtu/yr):* thermal energy output of the CHP system that is actually recovered and utilized in the facility/process
- *Useful electric output (kWh/yr):* electricity output of the CHP system that is actually used to replace the purchased electricity required to meet the requirements of the facility/process
- *F total CHP (kBtu/yr):* total fuel in consumed by the CHP system

DCEO's proposal then provides the following formulas to calculated the energy savings to be claimed, proposing 75% of the Btus should be credited to electric savings and 25% to gas savings.

S fuel CHP = (F grid + F thermal CHP) – F total CHP

Where:

"F grid" is defined as the fuel in Btus that would have been used to generate the useful electricity output of the CHP system if that useful electricity output was provided by the local utility grid.

F grid = Useful electricity output of the CHP X H grid

"H grid" is the heat rate of the grid and should be based on the average fossil heat rate for the state or for the EPA eGrid subregion and include a factor that takes into account T&D loses. The TRC utilizes an H grid of 10,622 Btu/kWh for ComEd territory and 10,967 Btu/kWh for Ameren territory (this includes line losses) for systems operating more than 6,500 hrs per year. For systems operating less than 6,500 hrs per year, the non-baseload heat rate values are utilized.

"F thermal CHP" is defined as the fuel in Btus that would have been used on-site by a boiler or heater to provide the useful thermal energy output of the CHP system. If the efficiency of the existing boiler/heater to be replaced is unknown, assume 75%.

F thermal CHP = Useful thermal energy output from the CHP system ÷ efficiency of the on-site boiler/heater that is displaced by the CHP system

"F total CHP" is defined as the total fuel in Btus consumed by the CHP system

Source: DCEO Public Sector CHP Pilot Program & TRM Update, Presentation at IL EE Stakeholder Advisory Group, Tuesday, May 27th, 2014, John Cuttica, Energy Resources Center, University of Illinois.

The above formula is technically correct, and it indeed provides a broad societal perspective on the overall efficiency gain from a CHP system. Thus, the AG and NRDC (and other parties) have supported use of this formula to estimate the efficiency of CHP systems for the purpose of determining what systems a program should support (and at what level). However, a distinction needs to be made between how to determine if a system is efficient enough to warrant promoting on the one hand and how to perform cost-effectiveness screening and estimate savings that will be counted towards utility goals on the other.

The AG and NRDC fundamentally believe that the formula for estimating total system efficiency across all fuels cannot tell us whether a system is cost-effective based on Illinois TRC cost-effectiveness guidelines (e.g. since some fuels cost more than others); nor can it tell us how much of each type of fuel is saved (since the change in use of some fuels will be different than for others, and can vary from application to application). Addressing those questions requires more precise estimation of savings of each fuel type. DCEO has proposed that be done by routinely allocating 75% of source energy savings to electricity and 25% to gas. That assumption requires at least two key leaps of faith: (1) that source efficiency should be the basis for estimating savings that would be counted towards goals; and (2) that gas-fired power plants are always on the margin on the electric grid. The AG and NRDC believe both of those assumptions are fundamentally flawed.

STATEMENT OF THE PROBLEM

Section 8-104 mandates that gas utilities achieve certain efficiency savings goals, based on their delivery of gas to retail customers. Specifically, it mandates:

> Natural gas utilities shall implement cost-effective energy efficiency measures to meet at least the following natural gas savings requirements [the gas savings goals], **which shall be based upon the total amount of gas delivered to retail customers,** other than the customers described in subsection (m) of this Section. [Section 8-104(c), Emphasis added]

In other words, the savings goals established by the ICC for gas utilities and DCEO are based on capturing a reduction in *delivered gas to retail customers*. This is essentially the customer gas savings, as recorded by each customer's gas meter. The electric Section 8-103 legislation similarly focuses on the net impact of electric savings at the customer's meter. While a well designed gas-fired CHP system could theoretically result in a net savings of natural gas at the primary Btu level, it will almost certainly increase gas purchased by the customer and reflected by the customer's gas meter. As a result, while an electric generator like Exelon might purchase somewhat less gas from an outside wholesale gas supplier, the actual gas sales to retail customers of the local gas distribution company (LDC) will increase, as will its retail revenue.

DCEO's CHP savings calculation proposal would provide the LDC with claimed gas savings, which would accrue toward reaching its efficiency goal of reducing retail customer gas deliveries. However, in practice this LDC will enjoy retail sales and revenue growth rather than an actual reduction in retail gas sales. In theory, with enough large CHP projects, an Illinois gas LDC could simply pursue a strategy of dramatically increasing its retail gas sales, while at the same time claiming that it met efficiency goals intended to decrease those retail sales. In this case, gas ratepayers would pay for load building that benefits the LDC shareholders, while not actually capturing the efficiency reductions intended by Section 8-104.

Further, DCEO's CHP approach will provide a strong incentive for gas utilities to pursue load building strategies, and therefore makes CHP projects much more desirable for LDC shareholders than other efficiency measures, even when those other measures are more cost-effective and provide greater return on investment to customers.

It also should be noted that natural gas-fired power plants are often not the marginal units whose use (and, therefore, fuel consumption) will decrease as a result of customer-sited electricity production from a CHP system. Indeed, in a recent report, MISO's Independent Market Monitor makes clear that natural gas-fired power plants "were a marginal unit in less than one-third of all intervals in 2013" and that coal-fired plants "set price in some locations in 93 percent of intervals, including almost all off-peak intervals."[3] Data from PJM also make clear that gas is not always – and perhaps not even most often – the electric generating fuel on the margin in its region.[4] We have not analyzed all the available PJM data. However, our analysis of the most recent month's data – for May 2014 – found that gas was on the margin only about 30% of the time; the other most common units on the margin were coal (42%), oil (22%) and wind (5%). In other words, even if one accepted DCEO's suggestion that source energy savings are what should be counted, the presumption that all the savings would be either electricity or gas is incorrect; some portion of the savings would have to be allocated to coal, oil, wind and, other fuels. That is obviously problematic because the efficiency programs have no goals for those other fuels. Moreover, given the frequency with which gas appears to be on the margin in the electric power pools serving Illinois, it is far from clear that gas consumption will go down appreciably, or at all, even if measured at the source.

Finally, the DCEO approach to estimating savings is inconsistent with what should be done to assess the cost-effectiveness of a CHP project. Allocating some of the site electricity savings to gas (because of the assumption that the baseline electricity consumption was fueled entirely by gas-fired power plants) would distort cost-effectiveness screening by using a gas avoided cost for a portion of the reduction in electricity demand. This is problematic in a variety of ways. First, it eliminates consideration of a portion of the peak generating capacity and T&D deferral benefits of reductions in electricity use at a site. Second, it confuses consideration of line

[3] Potomac Economics, Independent Market Monitor for MISO, *2013 State of the Market Report for the MISO Electricity Markets*, June 2014.

[4] http://www.monitoringanalytics.com/data/marginal_fuel.shtml

losses.[5] Third, it implicitly assumes that retail avoided gas costs are the same as avoided gas costs for supplying power plants. It is not clear that is appropriate. Fourth, it could undervalue carbon emission reductions by using a gas emissions rate for a portion of savings for which coal is the electric generating fuel on the margin.

AG/NRDC PROPOSAL

The Office of Peoples Counsel (AG) and the Natural Resources Defense Council (NRDC) propose that CHP savings should be counted and claimed in the same fashion as all other efficiency measures in the Section 8-103 and 8-104 programs. We believe this maintains consistency with existing ICC and legislative rules, ensures that CHP is treated on an equal footing with all other efficiency measures and eliminates the need to worry about which electric generating fuels are on the margin or how to calculate cost-effectiveness.

In short, savings would be calculated based on the actual electric and gas impacts at the customer meter, based on the following approach and formulas:

Electric Utilities claim credit for kWh savings:

kWh use at site (start) – kWh use at site (after CHP) = kWh Energy Savings from CHP

(This is the same term that DCEO shows above labeled: *Useful electric output (kWh/yr).* We do not propose any change in how this would be estimated.)

Gas impacts would be recorded based on estimates at the customer meter, and used for TRC screening and tracked. However, they would not count against the LDC progress toward efficiency goals. Gas impacts (using the same terms introduced by DCEO above) are:

Net Gas usage at site = F thermal CHP – F total CHP

Where:

F thermal CHP is the reduction in gas used to produce thermal energy that is not being provided by the CHP system
F total CHP is the gas fuel input used by the CHP system

Benefits of AG/NRDC Proposal

Under our proposed approach, savings claims will be consistent with actual energy impacts enjoyed by customers, and seen on the local electric and gas distribution systems. Because it will be important to quantify these values for purposes of educating customers about their potential investment, this simplifies the program delivery process by not requiring two sets of savings calculations. Further, because efficiency portfolio impacts are used for other planning

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[5] We acknowledge that DCEO's proposed calculations would include average T&D losses when estimating the primary Btus saved from electric generation. However, its proposal fundamentally treats all Btus that same, and then allocates a portion to electricity that may not fully reflect the true losses.

purposes such as load forecasting, it will ensure that the data tracked by program administrators will accurately reflect actual projected impacts on their energy systems. It will also ensure that gas utilities are not claiming efficiency savings progress toward goals when in fact they are increasing gas sales to their customers. Finally, it will facilitate proper TRC cost-effectiveness screening, because the Illinois cost-effectiveness screening tools are all based on the avoided costs of fuels at the end use level, not the primary energy level.

This approach may mean a gas-fired CHP system would result in electric savings and a likely increase in gas usage at the customer level. We do not propose that the gas LDC be penalized by this increased gas usage by subtracting it from its progress toward efficiency goals from gas efficiency measures. Rather, we suggest it be simply tracked separately as a gas increase, just as we do now with ancillary gas increases from other electric efficiency measures. For example, the Illinois TRM includes waste heat calculations that reflect an increase in gas usage from high efficiency lighting. While this is included for purposes of estimating TRC cost-effectiveness, the gas utilities are not currently penalized from this increase in gas usage against their efficiency goal progress. We note that adoption of DCEO's CHP proposal would be analogous to allowing the gas utilities to claim a portion of the overall gas Btu savings from high efficiency lighting based on a primary energy calculation that indicates overall gas is saved. We believe this creates perverse incentives and is not logical to somehow count gas savings from electric lighting efficiency that creates ancillary increases in LDC retail gas sales. We see no reason why CHP should be any different.

The new addition to Illinois Section 8-104 states that:

> "Energy efficiency" also includes measures that reduce the total Btus of electricity and natural gas needed to meet the end use or uses. (Section 8-104 "Definitions")

DCEO seems to interpret this as leading to a primary Btu savings calculation. We disagree. This is simply a clarification that makes clear that measures that save total gas and/or electricity are eligible efficiency measures.[6] However, this definition provides no new rules to indicate impacts should not still reflect the customer's impacts at the meter. Indeed, the latest version of the legislation makes clear that the gas goals are still based on reductions of gas delivered to retail customers, as shown above excerpted from the most recent version of Section 8-104(c).

WHAT OTHER STATES ARE DOING?

We have not completed an exhaustive study of how other states quantify savings from CHP. We also note that this may be dependent on whether an individual state has gas programs and goals or only electric, whether integrated gas-electric programs are offered, and subject to

[6] We note that there was never any prohibition against these measures qualifying as efficiency measures, and nothing exists in the legislation prohibiting or limiting fuel switching measures. However, we believe this was added simply to clarify that this is the case because some parties had expressed concerns that fuel switching eligibility was ambiguous.

specific laws and regulations prevalent in that state, which may differ from Illinois. There is precedent, however, in counting CHP savings consistent with the AG/NRDC proposal. Attachment A provides the Massachusetts policy for claiming fuel switching efficiency measure savings, including CHP. This policy is also used by Rhode Island. These two states both have extensive history in efficiency programs and rank in the top ten states by ACEEE.

In an effort to further explore this issue, we contacted the BG&E CHP program manager in Maryland.[7] She confirmed that BG&E also simply claims the customer reduction in electricity as electric savings, but includes the increased gas usage when screening the projects for TRC. We believe the BG&E approach is consistent with our proposal above.

[7] Personal communication with Kathryn O'Rourke, CEM, LEED AP, ICF, Manager, BG&E C&I CHP Program.

ATTACHMENT A – MASSACHUSETTS FUEL SWITCHING POLICY

MEMORANDUM

From	EEAC Consultants
To	PA CI Governance Team
Date	22 April 2010
Subject	Fuel-switching policies, cost-effectiveness, savings and cost tracking

INTRODUCTION

Fuel-switching— substituting equipment that uses a different fuel to provide the same service — can lower the total energy used to accomplish a desired outcome. For some applications, on-site use of fossil fuels is more efficient than the combined efficiency of electric equipment, line losses, and central plant generating efficiency (e.g., space heating with a boiler or furnace vs. electric resistance heating). In others, on-site electric use can be more efficient, usually when electricity is used to move thermal energy from the environment to a desired end-use (*e.g.*, heat pump space heating or domestic water heating), or in specific industrial processes (*e.g.*, injection molding machines). Fuel-switching can be a cost-effective means for PAs to achieve energy and peak reduction goals. It is important to determine how to attribute the benefits and costs to all of the participating utilities. How do the costs of implementation and administration get divided; how are savings calculated, and who should claim them? Are there safeguards in place to ensure that the utility that notes increased usage from switching to its fuel type is not impacted unfairly when it tries to meet its savings goals? This memorandum describes a framework for: 1) defining eligibility criteria for fuel switching efficiency measures to be promoted and funded through the PA efficiency programs; and 2) establishing data tracking and reporting rules for eligible fuel switching measures whose implementation is attributable to PA efforts.

ELIGIBILITY CRITERIA

The Green Communities Act calls for the capture of all cost-effective gas and electric efficiency opportunities by the PAs. While it does not specifically discuss fuel switching measures other than combined heat and power (CHP), the absence of any prohibition of fuel switching, along with explicit support for promotion of CHP — which is fundamentally a fuel switch — has been interpreted as both allowing and requiring PAs to pursue all cost-effective fuel switching opportunities.

Cost-Effectiveness Criteria

The DPU has made clear in its Order in Docket 08-50 that cost-effectiveness criteria for efficiency program measures is the Total Resource Cost (TRC), and that this test is appropriate for all PA portfolio efforts, including CHP and demand response:

> "As described in Section III.A, above, the Department found that the Total Resource Cost test is the most appropriate test to use in evaluating the cost-effectiveness of energy efficiency programs. We see nothing to suggest that new types of energy efficiency programs (e.g., combined heat and power projects and demand response programs) should be evaluated any differently than traditional efficiency programs. Such new programs may pose new challenges in terms of identifying and quantifying all the relevant costs and benefits but there is no need to deviate from the sound approach of the Total Resource Cost test, which includes all the costs and benefits that are experienced by either the energy system or the program participant." D.P.U. 08-50, at 34.

Thus, cost-effectiveness screening of fuel switching opportunities should be done consistent with any other efficiency measure, quantifying its costs and savings, and determining benefits by applying the energy savings to the respective avoided costs for each energy source impacted. As with any measure, other quantifiable and significant costs or benefits should be included (*e.g.*, water savings, O&M costs or savings, salvage value of early retired equipment, etc.)

Some PAs have expressed concerns that the avoided costs for fuel oil do not fully reflect the true societal costs of exploration, drilling, geopolitics, emissions, and other externalities. However, the DPU explicitly declined to order PAs to include any externalities based on past MA Supreme Court precedent (D.P.U. 08-50, at 16, 17). Therefore, while true societal costs for oil may be undervalued more than other fuels, PAs should allow cost-effective fuel switching to oil based solely on established avoided costs.[8] However, it is important to note that the DPU has ordered that environmental compliance costs, including those projected as reasonable and likely from state, regional or federal carbon regulation, should be included as these are viewed as best estimates of actual future environmental compliance costs, and therefore internalized in the costs of future energy (D.P.U. 08-50, at 17).

The DPU has focused cost-effectiveness criteria at the program level, and does not explicitly require that all individual measures pass the TRC (D.P.U. 08-50, at 19-20). However, the DPU makes clear this is intended to allow PAs some flexibility to promote certain measures that are integral to a broader package of cost-effective measures (*e.g.*, increased ventilation when air sealing a home to ensure good indoor air quality), when interactions between measures result in a strictly non-cost-effective measure (when analyzed alone) to increase the overall net benefits of a project, or for market transformation initiatives that expect that long term program results will be cost-effective over time by increasing measure adoption and bringing costs down. Because none of these exceptions typically apply to fuel switching measures, PAs should

[8] These are provided in Synapse, *Avoided Energy Supply Cost in New England: 2009 Report*, August 2009.

only promote cost-effective fuel switching measures unless they can show that one of these situations exist and that promotion will lead to greater net benefits for a particular project or over time through market transformation.

Energy Sources

The focus of the PAs' efficiency portfolio is to reduce electric and gas usage, and program funds are collected from electric and gas ratepayers. As a result, efficiency measures that save non-regulated fuels (*e.g.*, oil, propane) are not eligible under the PAs' initiatives. However, there is no prohibition against increasing use of non-regulated energy sources as part of a measure or package of measures that cost-effectively save electricity or gas. As a result, fuel switching away from electric or gas to any alternative fuel should be eligible so long as it passes a TRC test.

The DPU has adopted the 2009 AESC study as the source of avoided costs for use in cost-effectiveness screening.[9] In addition to electric and natural gas avoided costs, this study provides estimates for:

- No. 2 fuel oil
- No. 6 fuel oil (commercial or industrial applications with relatively large volume purchases only)
- B5 and B20 biofuel blends (residential or small volume purchase applications only)
- Propane
- Kerosene
- Wood (cord wood and pellets) (residential or small volume purchase applications only)

While there may be a unique instance where an appropriate avoided cost is not readily available (*e.g.*, biomass), the above fuels should cover most if not all likely opportunities identified by PAs and pursued by customers. In addition, we anticipate because of the wide availability of natural gas in most of Massachusetts, and the relative price and environmental advantages of gas over oil or other fossil or wood options, that the vast majority of cost-effective fuel switching opportunities will be between electricity and natural gas. That said, any switch to a non-regulated fuel that passes the TRC test would be eligible for promotion and funding through the utilities program. This will ensure that all energy sources are treated on an equal footing, compliant with DPU policy, and avoid concerns about load building or other competitive issues.

Because the intent of the PAs' 3-year plans is to provide integrated, fuel-blind, gas and electric efficiency services, no bias for or against any particular fuel should be applied in identifying or assessing fuel switching options. We expect that all PAs (whether gas or electric) will identify and analyze fuel switching opportunities consistently, and that any PA can promote a measure that moves either away from or to the fuel it sells if cost-effective.

[9] Synapse, *Avoided Energy Supply Cost in New England: 2009 Report*, August 2009.

Cost Allocations

It is expected that gas and electric PAs will work collaboratively to deliver integrated programs to customers. As a result, all PAs will attempt to identify and promote all cost-effective fuel switching opportunities regardless of whether they involve a move to or away from its energy source sold, or even whether the energy source it provides is involved in the potential project (*e.g.,* a gas PA promoting a fuel switch from electricity to oil). However, precedent in Massachusetts is that electric ratepayers fund electric savings and gas ratepayers fund gas savings. Therefore, consistent with other efficiency opportunities and CHP, rebates and other program costs associated with fuel switching should be allocated to the PA that provides the energy being switched away from (*e.g.,* the energy source that will have reduced usage). These cost allocations should be handled consistent with mechanisms to be set up by the PAs to track, reconcile and transfer funds among themselves for other measures and/or programs.

COUNTING AND TRACKING FUEL IMPACTS

While many efficiency measures may result in either increases or decreases in secondary fuel usage (e.g., increased gas usage to compensate for reduced waste heat from efficient lighting), these effects are usually minor. In contrast, fuel-switching results in large changes in the usage of two fuels. This complicates the allocation of savings and economic impacts when PAs promote fuel-switching measures. The following bullets present a consistent and transparent framework for doing so, consistent with established policy for CHP tracking.

- **Accurately track all gas and electric impacts at the customer meter.** Savings in one fuel and increased usage in another should be reported as separate line items in data tracking systems and reports. Electric utilities should not convert increased gas usage to negative benefits and combine them with other non-electric benefits, nor vice versa. Showing all changes in fuel usage helps create a complete picture of fuel switching impacts. When switching to a non-regulated fuel, the increase in the non-regulated fuel usage should be tracked and maintained in physical units, but can also be treated as a non-regulated fuel cost and should be bundled with other NEBS for purposes of the Value metric.

- **Credit one PA with savings towards program goals.** The utility with reduced electric or gas energy usage will count these savings along with all other efficiency measure savings and receive credit towards their overall program and portfolio savings goals. On the other hand, the utility with increased usage will not be penalized with respect to achieving their efficiency program and portfolio savings goals. If the PAs promote and incentivize the installation of high efficiency equipment (above new baseline) in a fuel-switching project, those savings above baseline could contribute towards savings goals for the respective fuel (see program design issues below for more detail). For purposes of tracking and reporting, any increases at the customer meter in gas or electricity will be tracked in physical units, and reported as a line item separate from savings from other efficiency measures. While this fuel increase will not be subtracted from efficiency savings for purposes of meeting goals, it is essential that they be tracked and reported to provide a clear picture of actual net impacts in MA on each PA system. This data will be used for purposes of calculating any loss based revenue adjustments, as well as for future planning, forecasting, net emissions impacts, and potentially other issues. This tracking framework is consistent with that established for CHP projects.

- **Allocate net benefits based on PA contribution to incentive and other program costs**. If two PAs contribute to a fuel-switching measure, both will share credit for the net benefits as measured by the TRC test, in proportion to each PAs contribution to the project.

PROGRAM DESIGN

As with all projects, PAs should strive to maximize net benefits by capturing all cost-effective efficiency opportunities. Therefore, we expect that when a fuel switching project is identified, efforts to ensure that other cost-effective efficiency measures are implemented and that the highest cost-effective efficiency system using the new fuel is installed. For purposes of tracking and cost allocations, it is useful to view fuel switching measures as potentially comprising two distinct components: 1) the shift from existing fuel to a new fuel baseline efficient system (the "fuel switch"); and 2) incremental improvements in efficiency above the baseline new fuel system ("incremental efficiency").

Under a situation where the fuel switch is between electric and gas, the incentive for the fuel switch portion would be paid by the PA whose fuel is reduced. Additional incremental efficiency improvements would then be funded by the appropriate PA as usual, with savings claimed as compared to the new baseline fuel switch installation. For example, an electric heat customer switching to gas could get an incentive from its electric PA for the fuel switch and the electric PA would record the electric savings and gas increase to a baseline gas heating system. However, the customer should be encouraged to install a high efficiency gas heating system. If they for example installed a condensing furnace, the gas PA could provide the incremental-cost based rebate for the condensing furnace and claim the gas efficiency savings as part of its regular program. Similarly, other measures that effect heating *(e.g.,* shell or distribution system measures) would be tracked based on the gas savings they generate assuming a baseline gas heating system (obviously taking into account any interactions between efficiency measures).

If the customer wants to fuel switch to a non-regulated fuel, then the fuel switch to baseline equipment can be incented as usual. However, the customer would not then be able to take advantage of efficiency incentives that only saved the non-regulated fuel because no ratepayer funds are available for efficiency savings of non-regulated fuels. In other words, in the above example if the customer selected an oil furnace, then shell measure incentives for heating savings would not be available to them once the fuel switch happened. As a result, while switches to non-regulated fuels are eligible if cost-effective, in areas where gas is available, the ability of the PAs to offer a more comprehensive package of measures should provide a strong incentive for customers to use gas.

There have been discussions with PAs about a program design that requires efficiency measure adoption as a prerequisite to fuel switching incentives. This seems like a reasonable program design, and will ensure that other efficiency measures are considered at the same time and potentially allow for downsizing of the fuel switch system. In addition, it will encourage comprehensiveness and lessen concerns about a shift to non-regulated fuels. However, it is also possible that this requirement might result in less cost-effective fuel switching if some customers are not willing to consider other measures at the same time. We recommend this issue be further explored. Possible options include offering a more generous incentive for comprehensive treatment but not completely disallowing fuel switching without comprehensiveness. This would be similar to the comprehensiveness bonus we now offer in the lost opportunity program.