MEMORANDUM

TO: Karen Kansfield, Jonathon Jackson, Ameren Illinois Company

FROM: The Evaluation Team

DATE: 4/25/2013

RE: Evaluation Methods for Combined Heat and Power

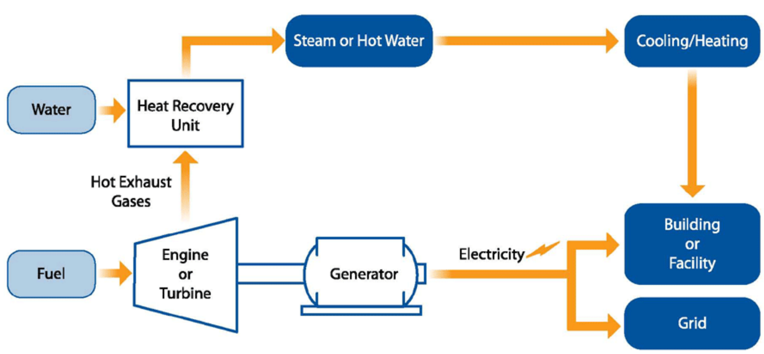
On March 27, 2013, Karen requested that the evaluation team provide Ameren Illinois Company (AIC) with comments on how our team would evaluate a Combined Heat & Power (CHP)[1] program. This was followed up via a separate email on April 1, 2013 with a list of specific questions from AIC to the evaluation team (included as Attachment 1).

We organized AIC's questions into the four main categories: gross impacts, net impacts, program implementation, and policy issues in the remainder of the memo as well as providing a brief introduction of CHP for context.

Combined Heat and Power

There are a variety of types of CHP systems – reciprocating engines, combustion (gas) turbines, and steam turbines. From a thermodynamic perspective there are two main types of CHP, topping and bottoming cycle systems. Figure 1 shows an example of a topping cycle CHP system. This is the most common CHP system. In this system, fuel[2] is first used as the energy source for a "prime mover" such as a gas turbine or engine, thereby generating electrical or mechanical power. Waste heat from the prime mover is then recovered and used to provide process heat (for industrial sites), hot water, or space conditioning for a site (either heating or cooling).

Figure 1. Example of a Topping Cycle CHP System



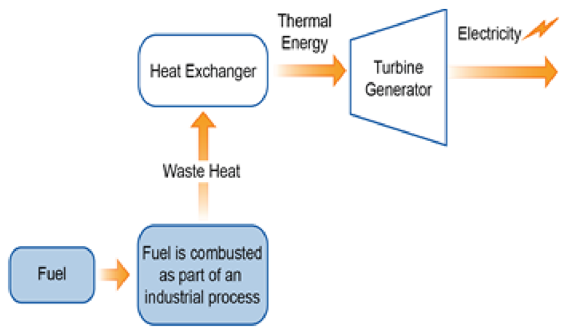
Source: U.S. Environmental Protection Agency (EPA) CHP Partnership www.epa.gov/chp/basic/index.html

[1] Also referred to as "cogeneration".

[2] Fuel can be natural gas, biomass, biogas, coal, waste heat, or oil.

Figure 2 shows a bottoming cycle CHP system (also called Waste Heat to Power, WHP) where fuel is first used to provide a thermal input to a furnace or some other high temperature industrial process. The rejected heat is recovered to create electrical power – often through a turbine.

Figure 2. Example of a Bottoming Cycle CHP System



Source: U.S. EPA CHP Partnership www.epa.gov/chp/documents/waste_heat_power.pdf

For energy efficiency programs, addition of a CHP plant using either topping or bottoming cycle will have different impacts. As such, the impacts occur when the turbine generator energy (created onsite) is substituted for the grid energy (from the utility). For the more common topping cycle CHP, the impacts must take into account the additional fuel used within the prime mover as well as the site electricity created by the generator.

Gross Impacts

Below are each of five questions posed by AIC along with our responses on how gross impacts would be evaluated for different system and fuel types:

1. <u>What is our opinion of using waste heat or steam pressure reduction for kWh generation in the current program?</u>

Bottoming cycle CHP systems (or waste heat/steam systems) are more common in heavy industrial sites and there are no reasons from an EM&V perspective for excluding them from the program. The EM&V methodology and metering requirements would be very similar to the methodology for topping cycle CHP systems used in commercial, institutional, and smaller industrial facilities. Larger sites will have control systems capable of logging the main data needs:

- Fuel consumed (assume it would be natural gas)
- Electricity produced
- Steam generated

One challenge is correctly metering steam production, with potentially high variability in the flow and uncertainty in measuring.

Sites installing smaller CHP, especially smaller package units, might not meter the thermal energy directly or even the gas consumption. To properly evaluate systems with these missing items we recommend additional metering equipment including recording gas meters and BTU meters.

2. <u>What special EM&V issues do they expect if a CHP project uses a renewable fuel?</u>

The methodology for verifying electricity generation and useful heat recovered is the same for renewable fueled and non-renewable fueled CHP systems. Additional metering equipment would be necessary if a facility is using both renewable and non-renewable fuel so that cost-effectiveness can be more accurately assessed since the cost of renewable fuel is different from fossil fuel and likely zero (e.g., biogas, sawdust, woodchips).

If the utility or state has goals for reducing greenhouse gas emissions, then there may be advantages to installing additional metering equipment to monitor the methane content and flow rate of the biogas to refine GHG emission reduction calculations. Note that if gas metering is required, it's best to install this equipment during construction of the CHP system.

Where renewable fuels are solid biomass (e.g. wood chips), metering fuel input has two issues: mass of the fuel and moisture content. For auger fed processes the mass flow of the solid fuel can be approximated by logging the run time of the auger. Moisture content is important because it determines the net heat content of the fuel. It is best determined through testing samples of the fuel. Metering fuel input and heat content would be useful in calculating the overall efficiency of the CHP systems to determine if systems are performing as expected from engineering calculations and assumptions.

3. <u>For CHP projects can we claim credit for reduced line losses since we're considering Point of Use applications?</u>

While line losses are reduced if the electricity generated is used on site, how the programs count savings (i.e., site savings and not source savings) may be more of the issue than if such losses occur. Whether transformer loss reduction can also be claimed depends on the voltage of the CHP system and on site transformers. In any scenario, each kilowatt-hour generated on site displaces more than one kilowatt-hour generated by a central plant.

4. <u>Should the claimed CHP program electric savings be limited to the kWh that can be used at the site, or include all kWh generated?</u>

For a facility using a CHP system to primarily offset onsite energy usage, the CHP system is most cost-effective when sized to fully use the recovered heat (rather than sized based on electricity needs which generally results in waste heat that cannot be utilized). This means that electricity is only exported to the grid when heating needs are at a maximum and electricity needs are at a minimum, for example on a winter night. When this occurs, we recommend the claimed savings include all kWh generated. This is standard practice for solar PV incentive programs. Solar PV performance-based incentive programs often cap rebates at 100% of the customer's load over a year, allowing customers to generate excess electricity during some periods and to generate less than needed during other periods. This same concept could be applied to an upfront incentive, where engineering calculations are submitted with the customer's application showing how much of the customer's annual electricity consumption is expected to be offset with the CHP system. The program could cap the incentive at a system size that offsets 100% of a customer's annual consumption.

5. <u>Should the program be limited to CHP that is integrated as part of a process or building, i.e. it cannot be a stand-alone generation plant?</u>

We recommend limiting the program to integrated processes with on-site generation. Those CHP facilities that are built to primarily feed electricity to the grid should be treated as a qualifying facility (QF) under PURPA requirements and are generally treated under different regulatory requirements than demand side management opportunities. As such, they may not qualify toward meeting the Illinois Energy Efficiency Resource Standard requirement.

Net Impacts

Net impacts take into account the counterfactual – what would have occurred absent program intervention. There are two theoretical viewpoints that are the foundation for the methods currently employed within energy efficiency evaluation.[3] However, only one is useful for determining net impacts from CHP.

The first viewpoint (called the positivist approach) states that causal relationships are not directly observable and one must use quantitative comparisons to look at the correlation of events and changes. Experimental designs such as used by behavioral programs employ this approach as do quasi-experimental designs that use billing data with a comparison group. There are several specific designs, but all use statistical data to infer causality. For CHP projects, expected to be implemented in industrial plants or large commercial sites, there are few projects and no comparable group for appropriate statistical analysis. While statistical analysis could occur using data pre and post-implementation, this shows change in use, not what would have occurred absent the program. As such, statistical methods are not able to be used to assess net impacts for this type of program.

Therefore, we must use the second viewpoint (called the realist approach) to assess net impacts. This approach defines causality in terms of real (and in principle observable) causal mechanisms and processes. This approach assumes that people can observe and report on important reasons behind behavior. Within energy efficiency evaluation, the self-report method applies this viewpoint.

Self-reporting can come in various formats, though. Energy efficiency evaluation practitioners have generally used a set of closed-ended scalar type questions to create a value that represents what would have occurred absent program intervention. These questions are typically put to participating customers, though market actors also are included at times. Additionally, open-ended questions that provide context have also been used to adjust the results from the original index of questions.

None of this is really new, though. It just serves as background for why self-reporting is the method of choice for a CHP program. For this type of program, we believe that the challenge to the evaluation team determining attribution is complicated by the following:

- The probable size of savings and associated incentive will make any results a "high-stakes" answer
- Organizational decisions are multi-layered and take time.
  - The evaluation team typically does not have access to each of the decision makers due to people leaving or insufficient budgets
  - The history of a utility working with their larger customers and talking about energy efficiency (or CHP) is typically not available as a source of information for possibly showing attribution.
  - Large scale capital projects often take a long time to come to fruition. Often these very large projects are undertaken for reasons other than the incentive. These projects could be operational imperatives versus being induced by an incentive.
- The federal government and now the Illinois state government is also involved with increasing CHP penetration. Both parties are bringing resources (although this may be relatively small resources) to AIC's customers that will play a part in helping the customer make a decision to move forward with CHP. Our evaluation industry currently has only a "broad-swatch" approach to apportioning impacts (e.g., using costs associated with multiple entities to assign savings).

[3] Please refer to Ridge 2009, for more complete discussion of these viewpoints.

To get around these challenges, we would expect to go beyond a simple net-to-gross battery of questions, although these questions would play a part in the overall answer. It would work best if the evaluation team works closely with the implementation team to provide a site-specific net-to-gross ratio (NTGR) shortly after the project closes so there is quick knowledge for the program in terms of net savings. However, once known, this information should not affect the incentive to the customer, but does provide an idea of the cost effectiveness of the program moving forward.

The actual analysis would include information gathered from multiple people, any available information in project files, existing policies of the site, federal compliance regulations (for EPA type of requirements), or email discussions. The analysis would begin with results from a battery of closed ended questions, but we need to go beyond any one value from that battery and take into account all data we have gathered. We would expect to adjust any original NTG value based on other information. This may increase or reduce the original value. We have experience performing this type of analysis, having done so many times. The final adjustment is arrived at through two independent analysts looking at the information gathered and coming to separate conclusions and then discussing reasons for any disparities. All aspects of this analysis are clearly documented.

With this type of program, we think that a pilot that works through both implementation and evaluation issues would be beneficial. Given that the potential for CHP within AIC service territory is probably not high (although we do not know exactly what the potential is) we think that somewhere between 5 and 10 completed projects would be sufficient for a pilot on the evaluation side. (During this period, we recommend that any projects should have a deemed NTGR that is agreed to between AIC and ICC staff.) As part of this effort, we suggest that the evaluation and implementation team work together to come up with a high level screening tool for free ridership. This tool would be expected to screen out only those projects where the likelihood of the customer being a full free rider (i.e., NTGR=0) is very clear. The data from this tool may be used to inform evaluation questions afterwards, but is not expected to give a specific NTG value.

Program Implementation

AIC may use a split incentive payment structure whereby part of the incentive payment is provided to the customer at installation while the remainder is provided a year later based on performance. We have seen split incentive payments for wind programs and it appears to be a prudent use of incentives. Savings from this type of implementation would be garnered across two program years. Similar to the current "carryover" method for CFL's, the evaluation team would track a specific portion of the savings in year one and then assign savings as a true up in the second year. The proportion of savings within the first year is set based on the proportion of the incentive. For example, if the program paid 75% of the incentive in year one, then the first year gross and net impacts would be 75% of the estimated values. The second year may true up such that there is only 21% of the incentive that is applicable. For this second year, the program would accrue only 21% of the first year impacts.

Policy Issues

There were three to four questions posed to the evaluation team that appear to be policy questions that are best answered through discussions with ICC staff and other SAG members. While our team has opinions on these questions, we believe that ultimately, the way that we would conduct our evaluation and provide results for these questions will be based on choices made elsewhere.

1) What program issues do they see for a CHP project that generates electricity, but requires more gas use?
    - Our team believes that additional gas use should be included in the evaluation. We can perform our analysis on a BTU basis, but believe there would be difficulties in separating out the BTUs afterwards. However, we recognize that this choice is

bound with question 2) below and what is ultimately shown in results may depend on who is providing the natural gas.

2) Do they see any issue with claiming gas savings for a CHP project at an "opt-out gas customer" or for an "electric only customer"?
    - We understand that the current policy may be to not count non-customer savings towards goals, but to include those savings within TRC calculations. We have no opinion about this type of use.
    - Aside from the above bullet point, it seems that who pays into specific energy efficiency riders and how savings are claimed is a policy issue. (This seems to play out in the single-fuel versus dual-fuel customers within AIC service territory.) For our part, if gas savings can be claimed, we believe that any additional gas use should also be accounted for.
3) What EPA regulations or IL net metering regulations might influence their [the evaluation team's] assessment of program impact?
    - We discussed the EPA regulations in the Net Impacts section, above. However, we would need to become more familiar with the IL net metering regulations to answer this question thoroughly. At this point, we believe that this may be a policy question as well.

Additionally, there is one question that we have discussed within the gross impact section that is also a policy question (shown next).

- Should the program be limited to CHP that is integrated as part of a process or building, i.e. it cannot be a stand-alone generation plant?

The evaluation of either an integrated or stand-alone system would be similar, but whether energy efficiency funds should be used to increase generation capabilities that a third party then sells to AIC customers is a policy issue.

While not a question posed to the evaluation team, this type of program has differences that need to be handled within any cost effectiveness tests. Since other parts of the cost effectiveness tests appear to have been covered through policy choices, we have added this information to this section. The California Standard Practice Manual (SPM) states that the labeling of a project or program is important as it affects how the costs and benefits are handled within cost-benefit tests.

> *Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building). Self generation refers to distributed generation (DG) installed on the customer's side of the electric utility meter, which serves some or all of the customer's electric load, that otherwise would have been provided by the central electric grid.*
>
> *In some cases, self generation products are applied in a combined heat and power manner, in which case the heat produced by the self generation product is used on site to provide some or all of the customer's thermal needs. Self generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines. [Standard Practice Manual, page 2]*

An example of potential differences from the regular demand side management programs is that the analysis of the cost effectiveness of self-generation (which is how CHP projects could be labeled) should account for the utility interconnection costs. Attachment 2 provides a listing of the costs and benefits used within an analysis of cost-effectiveness for distributed generation within California.

References

California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects. 2002.

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The State and Local Energy Efficiency Action Network. 2013. *Guide to the Successful Implementation of State Combined Heat and Power Policies.* March 2013

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Attachment 1 – Original list of evaluation questions from AIC to evaluation team

The eMail from Karen Kansfield to Mary Sutter dated 4/1/13 is copied over verbatim below:

As requested we have developed a list of questions for EMV for a potential Cycle #3 CHP program offering. But first we want to make sure they know our understanding of the eligible customers which are:

- Combination gas-electric customers
- Electric only customers
- Electric customers and gas customers (including opt-out gas customers)

Here are our questions for EMV:

- What experience do they have providing EMV for CHP programs and what lessons learned can they share with us regarding EMV issues?
- What potential free-rider challenges do they foresee?
- How would they expect us to document program impact if a CHP project also received technical or financial assistance from alternative organizations (ie: DOE)?
- What EPA regulations or IL net metering regulations might influence their assessment of program impact?
- What is their opinion of using waste heat or steam pressure reduction for kWh generation in the current program?
- What program issues do they see for a CHP project that generates electricity, but requires more gas use?
- Do they see any issue with claiming gas savings for a CHP project at an “opt-out gas customer” or for an “electric only customer”?
- What special EMV issues do they expect if a CHP project uses a renewable fuel?
- For CHP projects can we claim credit for reduced line losses since we’re considering Point of Use applications?
- What is their opinion of using a split incentive payment; upon installation the applicant is paid by installed capacity and then one year later they receive a performance payment based on metered data? When would the program claim the savings based on this approach?
- Should the claimed CHP program electric savings be limited to the kWh that can be used at the site, or include all kWh generated?
- Should the program be limited to CHP that is integrated as part of a process or building, i.e. it cannot be a stand-alone generation plant?

Attachment 2 – California Cost Benefit Inputs for Distributed Generation

Benefits

Benefit	PCT	TRC	STRC	PA
Avoided line losses	NA	Included	Included	Included
Avoided purchase of energy commodity and resource adequacy costs	NA	Included	Included	Included
Avoided transmission and distribution (T&D) costs (T&D investment deferrals)	NA	Included	Included	Included
Combined heat and power (CHP) plant-specific benefits	Included	Included	Included	NA
CHP gas and electric bill savings	Included	NA	NA	NA
Environmental benefits (CO_2, NOx, and particulate matter emissions)	NA	Included*	Included	Included
Market transformation effects	Included	Included	Included	NA
Net energy metering bill credits	Not Included	NA	NA	NA
Rebates/Incentives	Included and can be run with and w/out rebates	NA	NA	NA
Reduced electricity bills	Included	NA	NA	NA
Reliability benefits (both system and customer ancillary services/VAR support)	Not included in SGIPce model	Included	Included	Included
Standby charge exemption	Included	NA	NA	NA
Tax credits/depreciation	Included	Included	Included	NA

Benefit	PCT	TRC	STRC	PA
Utility interconnection not charged to DG customer	Not included in SGIPce model	NA	NA	NA

Source: Itron 2011. Table 3-1

Costs

Costs	PCT	TRC	STRC	PA
Costs of DG system, interconnection, emission controls and offset purchases	Included	Included	Included	NA
Increased IOU fuel transportation costs for gas-fired DG	NA	NA	NA	Included
Net energy metering costs	NA	NA	NA	Not Included
Nonbypassable charges (PGC, DWR, nuclear decommissioning)	Included	NA	NA	NA
Operation maintenance, fuel, ongoing emission offset purchases	Included	Included.	Included	NA
Program administration	NA	Included	Included	Included
Reliability costs (system cost of additional ancillary services/VAR support)	NA	Not Included	Not Included	Not Included
Removal costs (less salvage)	Not Included	Not Included	Not Included	NA
Utility interconnection	NA	Not Included	Not Included	Not Included
Utility rebates/incentives	NA	NA	NA	Included

Source: Itron 2011. Table 3-10