The Alliance for Industrial Efficiency has had a number of calls with EPA staff to address questions about the treatment of industrial energy efficiency in the Clean Power Plan and proposed FIP. Summaries of the issues we have addressed in these conversations follows. (parenthetical page numbers refer to pages in the pre-publication version of the Rule and FIP).

Questions about Treatment of IEE in the CPP and the FIP

State measures are not federally enforceable (80 Fed. Reg. at 64667, 80 Fed. Reg at 64836). What’s the practical difference between state and federal enforceability?

Any requirements that apply to an affected EGU must be federally enforceable (i.e., subject to federal law, including citizen suit provisions). Generating an ERC does not trigger federal enforceability; liability continues to fall on the EGU. State enforceability will vary by state, but means that the entity is only subject to state law or contract. Notably, large energy users have experience with contracts and will be able to negotiate terms that they can live with.

What types of actions might qualify as backstops (80 Fed. Reg. at 64667) (where state measures fail)?

If state measures prove inadequate, EPA will impose an emission standard that would apply to the EGU. This standard will guarantee that the CO$_2$ goal is met. The EGU would then have to guarantee performance by the fleet. This can still be done through a trading program.

While EM&V is not technically required for mass-based plans, what does this mean in practice? It seems that some form of EM&V would be required to calculate set-asides. Moreover, the regulations seem to require EM&V for mass-based plans (despite preamble language to the contrary). For instance, §5705 (which seems to be intended for states with

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2 At 64836 (“because the state measures would not be federally enforceable emission standards, the plan must also include a backstop of federally enforceable emission standards for all affected EGUs…”)
3 At 64667(state measures plan must include “contingent backstop of federally enforceable emission standards for affected EGUs.”)
States have discretion to allocate allowances however they see fit. Apparently, the cited text only applies in a few discrete instances: (1) where a state is using a set aside for EERE to opt into the CEIP or (2) to meet a plan requirement to address potential emission leakage. In those contexts, EM&V would be required to demonstrate that savings are actually being realized. No EM&V is required for allowances in a mass-based program otherwise (and a governor, e.g., would be free to reward a priority project with additional allowances). That said, states are still likely to develop EM&V programs to ensure that public rate-payer funded dollars are allocated on a fair and reasonable basis.

The EM&V requirements are not intended to be onerous; they should be based on M&V practices that are already in use/ represent best practice.

The “easiest” way to avoid EM&V is to auction allowances and use the proceeds to incentivize EERE. This is what happens with RGGI. NY has a dedicated CHP program – and is interested in incentivizing and promoting CHP. Auction revenue elsewhere could similarly be used for that purpose.

I’ve heard stakeholders say the mass-based targets are less demanding. Is that right?

The mass- and rate-based limits are intended to be equivalent. [this may not be correct; I’ve since heard multiple stakeholders explain that the mass standards are less demanding – particularly mass standards limited to “existing sources”]

Did EPA find that one approach (mass v. rate) would have less of an impact on electric rates than the other? Would industrials favor one approach?

EPA conducted national modeling scenarios, but did not consider impacts on a state level. State impacts are subject to many state-specific plan details (e.g., PUCs have discretion in determining retail rates, impact may depend on whether allowances are sold or freely given). This national modeling showed costs were slightly lower with a mass-based plan. In fact, mass-based plans might have lower compliance costs (b/c of M&V). [I’ve since heard others say that
EPA’s analysis shows mass standards are about 40% cheaper to implement] Ultimately, bills are more important than rates – and EE will lower bills under either approach.

Some parties (e.g., ESCOs) would like to receive allowances (through a mass-based system) that they can sell as an “incentive.” On the other hand, they might also want to generate ERCs from a rate-based system. If a state anticipates growing emissions (e.g., growing population or industrial base), it may favor a rate-based plan. [Ultimately, we believe that industrial efficiency can work under either approach – and encourage stakeholders to advocate to ensure provisions are included to advance IEE, regardless of whether the state adopts a mass- or rate-based plan).

Is demand-side management limited to “non-emitting measures” throughout the rule – or does it ever extend to CHP? (80 Fed. Reg. at 64900)4

CHP is in its own category. DSM is limited to non-emitting activities.

EPA projects that the CPP will spur a 7% reduction in electricity demand by 2030 from demand-side EE, reducing electricity bills in 2030 by $7/ month for families and business. (EPA Fact Sheet).5 Does this account for CHP? If not, does that mean that savings are potentially even greater?

No. This analysis is limited to utility-funded ratepayer programs (limited only because EPA had the best data for such programs). Arguably, this is a conservative finding, since it does not include privately delivered EE or CHP. EPA does not favor certain types of EE activities over others – so long as they are quantified and verified.

The CEIP offers a limited opportunity for EE: it is limited in geographic scope (to low-income areas), temporally (only for two years), and will be competing against other activities (capped at 300-million short tons) (80 Fed. Reg. at 64670).

Is CHP eligible for early action credit in the CEIP?

No. As written, renewable credits under the CEIP are limited to wind and solar (thus biomass CHP would not be eligible). Credits are given to qualifying EE activities in low-income

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4 At 64900 (“Eligible DSM actions are those that are zero-emitting and avoid, rather than shift, the use of electricity by an electricity end-user”).

5 EPA, FACT SHEET: Energy Efficiency in the Clean Power Plan (http://www2.epa.gov/cleanpowerplan/fact-sheet-energy-efficiency-clean-power-plan)
communities (to be defined later); it is not limited to activities in the residential sector [e.g., process efficiency improvements in the industrial sector would likely qualify]. Qualifying activities are limited to non-emitting actions.

EPA will be taking subsequent action on the CEIP, so is taking comment on the program. [We should urge a more expansive definition of EE and note that many industrial areas are low income]

The rule appears to limit electricity sales from WHP units (80 Fed. Reg. at 64902-64903). This may present a significant barrier to heat recovery along natural gas pipelines. WHP units located on natural gas pipelines are intended to be eligible – even if they are providing electricity into the grid. This language was intended to discourage inefficient bottoming cycle units (i.e., those sized not to thermal but to sell electricity). The reference to MWh is not limited to MWh electric. [we may want to ask EPA to clarify this] EPA seems to be saying that the mechanical load at a compressor station would still qualify.

WHP units that require additional fuel (to get the heat to the right temperature to generate electricity) will need to factor in that additional fuel used.

EPA is taking comment on whether the FIP should allow ERCs for CHP. We should respond in the affirmative. Note that the rate-based model rule includes details about how to value ERCs for CHP, so this is a logical extension.

Can a large-scale (e.g., > 25 MW) CHP system covered under 111(b) generate ERCs? The rule says (80 Fed. Reg. at 64950) that EGUs subject to subpart TTTT (i.e., 111(b)) cannot generate ERCs, but explicitly exempts CHP from this proscription (id.).

The CHP exemption at 1495 refers to new sources – so only the “uprate” of an existing source (e.g., increasing an existing unit from 100 to 105 MW) would be eligible for ERCs.

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6 64902 & n. 971 ("The MWh of electrical output from a WHP unit that can be recognized may not exceed the MWh of industrial or other thermal load that is being met by the WHP unit, prior to the generation of electricity.” & “This limitation prevents oversizing the thermal output of a WHP unit to exceed the useful industrial or other thermal load it is meeting, prior to generation of electricity.")
Would marginal improvements to existing systems (i.e., those predating 2012) be able to generate ERCs?

Only capacity uprates could be credited. Software improvements that result in increased efficiency could not.

The final rule exempts certain industrial CHP facilities from being treated as affected EGUs for the purpose of consistency with 111(b) (80 Fed. Reg. at 64716). We do not necessarily disagree with these exemptions, but seek additional clarification to be able to better explain them in our education and outreach efforts.

- We’ve been told that “most industrial” units are exempt. Is this right?
- What does it mean to exempt those units that have “historically limited annual net electric sales to a utility power distribution system to the product of the design efficiency and the potential electric output or 219k MWh (whichever is greater) or less”? (80 Fed. Reg. at 64716) What is the definition of “design efficiency”? And what types of units is this exempting?

Most industrial units will be exempt from the rule. It exempts new and existing combustion turbines that are not connected to a NG pipeline and biomass units. Only “PURPA machines” (i.e., those designed to produce as much power as possible, with very little heat load) are intended to be covered. Most “normal” industrial CHP systems will be exempt. More efficient units will be able to sell more electricity back to the grid (i.e., the product of total design efficiency and electric output will be higher).

111(b) has better information on the definitions. The exemptions are discussed at length in the preamble to 111(b) – 80 Fed. Reg. at 64686, 64959; the term “design efficiency” is defined in 111(b) – 80 Fed. Reg. at 64806. The final CPP definition section, 40 C.F.R. 60.5880, 80 Fed. Reg. 64959, now says that any terms not defined there are used in the CPP as defined in, among other things, 40 C.F.R. pt. 60 subpt. TTTT (the CO2 NSPS for EGUs).

Units that have a lot of thermal output will be more efficient. Those units are less likely to be covered by the rule for two reasons: (1) they are not making much power and (2) they are not selling a lot of electricity.

The rule includes a list of 395 potentially affected units; however, most of these will likely “fall out.” EPA included them because it did not have design information nor information about their actual electric sales available.

These exemptions are in the final rule language (thus not open to comment), though it is
possible that stakeholders will seek reconsideration. EPA intends to provide clarification in the final publication.

How do you document design efficiency/ net electric sales for EPA?

When a unit is first installed, it will typically run a test (e.g., ASME, ISO), which will establish design efficiency. That would set the design efficiency for the life of the unit. 111(b) lays out several test methods that can be used (in its definition of design efficiency at 80 Fed. Reg. at 64806). 111(d) does not yet have these details, but they will be included when the rule is published. Where existing units have that information, they can rely on similar tests.

Unless the state adopts a federal plan, the type of qualifying documentation will be at the state’s discretion. Most systems are nowhere near the sales/capacity threshold. If they are, they are likely already reporting to the Clean Air Markets Division. That same reporting will suffice under 111(d).

What are net electric sales?

Net electric sales are defined in 111(b) (80 Fed. Reg. at 64960) (and will be defined in 111(d) when the rule is published). It refers to the amount of electricity produced at the generator minus the purchased power of the facility that’s operating -- even if the system is owned by a third-party operator. This recognizes the complex owner-operator relationships of CHP systems.

Would a facility that converts from coal to gas (a lower emission fuel) in 2014 get credit for the reduction in emissions that come along with the new fuel?

EPA does not believe that fuel switching is identified as an eligible resource in k(1). The rule focuses on electrical emissions. There is no credit for switching from a higher carbon fuel to a lower carbon fuel on its own. If you had an existing unaffected coal-fired CHP system, and you changed to gas, it would impact the emissions rate and the amount of ERCs it could generate.

Measurement of CHP Benefits
We are pleased that the rule provides guidance in calculating ERCs for CHP – but are concerned that it may underestimate these benefits. The rule provides guidance on netting out incremental emissions from CHP. The approach recognizes both that CHP uses additional fuel – and that the incremental emissions related to electrical output are low. In particular, EPA prescribes that “a non-affected CHP unit’s electrical MWh output that can be used to adjust the reported CO₂ emission rate of an affected EGU should be prorated based on the CO₂ emission
rate of the electrical output associated with the CHP unit (a CHP unit's 'incremental CO₂ emission rate') compared to a reference CO₂ emission rate. This 'incremental CO₂ emission rate' related to the electric generation from the CHP unit would be relative to the applicable CO₂ emission rate for affected EGUs in the state and would be limited to a value between 0 and 1.” (80 Fed. Reg. at 64902). The applicable CO₂ emission rate is not defined in the rule itself; however, the FIP (80 Fed. Reg. at 64990) references Table 6, which in turn, identifies target emission rates (in 2022 and 2030) for two different categories of technologies ((1) steam generating units (SGU) or integrated gasification combined cycle units (IGCC) and (2) combustion turbines). Table 6 is presented below:

<table>
<thead>
<tr>
<th>Technology</th>
<th>2022-2024 Compliance Rate</th>
<th>2025-2027 Compliance Rate</th>
<th>2026-2029 Compliance Rate</th>
<th>Final Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>SGU or IGCC</td>
<td>1,671</td>
<td>1,500</td>
<td>1,380</td>
<td>1,305</td>
</tr>
<tr>
<td>Stationary combustion turbine</td>
<td>877</td>
<td>817</td>
<td>784</td>
<td>771</td>
</tr>
</tbody>
</table>

This implies that the proration of the MWh output of a non-affected CHP unit in determining ERCs is based not on the current emission rates of affected EGUs, but instead on the target rates, which are notably lower. If this is correct, ERCs from CHP units will be heavily discounted compared to ERCs from traditional demand side efficiency measures.

- What does the “reference CO₂ emissions rate” refer to? (80 Fed. Reg. at 64902) We believe it should be based on what’s actually being displaced – rather than the target rate of affected EGUs in the state.
- Which affected technology rate standard should be used – SGU or Stationary Combustion Turbine? (the two technologies in Table 6 have markedly different limits) Does it depend on the fuel-type used by the non-affected CHP?
- Why are the specific technology limits used, and not the state targets or limits?
- Is this measurement issue limited to rate-based plans – or would it come up in determining set-asides under a mass-based plan as well?

NB: EPA is taking comment on this issue in the proposed federal rule – and we should definitely weigh in. We will prepare template language that other stakeholders can use.

EPA confirms that the determination of an appropriate CO₂ emission reference rate as presented in the model rate-based rule in the draft FIP is open to comment. The intent outlined in the model rule is to treat CHP as a “low emissions generating resource.” This may be problematic, since it means that CHP will not be treated like energy efficiency, but instead be
treated in a manner “consistent with the general accounting method for other generating resources.” The model rule suggests that states should prorate the emissions rate credits from a non-affected NG-fired CHP unit based on the relative ratio of incremental emissions from the CHP system and the CPP target emissions for natural gas-fueled affected electric generating units (i.e., a stationary combustion turbine in Table 6, above). If true, this would virtually eliminate any economic value for ERCs generated by non-affected natural gas CHP systems. [This is a significant concern and we will draft template comment language to address]