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Evaluating Simplified Methods of Estimating Displaced Emissions in Electric Power Systems:
What Works and What Doesn't

FINAL DRAFT

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Executive Summary

This paper expands on a paper written for the Commission on Environmental Cooperation in 2003, titled *Estimating the Emission Reduction Benefits of Renewable Electricity and Energy Efficiency in North America: Experience and Methods.* That paper explored the important methodological issues related to estimating the net air impacts of new resources in electric power systems. The paper also reviewed a number of projects in which net emission benefits have been estimated, including projects using power system simulation models and projects not using such models. Over the past year, there has been growing interest in further evaluation of the non-modeling-based methods. The goal of this paper is to lay the groundwork for determining which non-modeling-based method can provide the best estimates of displaced emissions and under what circumstances use of that method would be appropriate.

The authors begin by examining three aspects of power system operation and development that are critical in determining the emission impacts of new resources. These three aspects are:

- Matching generation to load hour to hour;
- Transmission constraints and the available set of generating units; and
- Capacity additions and retirements.

The first two aspects involve day-to-day system dispatch, and they determine which generating unit or units are on the margin, and thus which units are likely to be affected by a new unit or reduced load. The third aspect deals with longer-term changes in a power system, and it determines the long-term emissions impacts of a new resource.

Next, the authors examine the three simplified (i.e., non-modeling-based) methods of estimating emissions displacement, which are most commonly described in the literature. These methods are distinct primarily in the way that they seek to identify the marginal generating unit in the relevant system—the unit likely to be affected by a new project. One method identifies this unit based on geography; the second identifies it based on unit type; and the third, based on a load curve analysis. The authors conclude that the first two methods are not likely to yield accurate results because they cannot reliably identify the marginal generating unit(s). They conclude that the third method—the load curve analysis—is potentially far superior to the other methods. However, a number of adjustments and assumptions must be made in this method, and the method ignores the impact of transmission constraints on generating unit dispatch. More work is needed to determine how robust this method is.

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1 Introduction

This paper expands on a paper Synapse Energy Economics wrote for the Commission on Environmental Cooperation (CEC) in 2003, *Estimating the Emission Reduction Benefits of Renewable Electricity and Energy Efficiency in North America: Experience and Methods.*[1] That paper explored the important methodological issues related to estimating the net air impacts of new resources in electric power systems, and it reviewed a number of projects in which net emission benefits have been estimated. We concluded in that paper that estimates of displaced emissions over the short term should be based on the emission rate of the marginal generating unit(s) in the system, and that for the long term they should be based on the units likely to be added and retired in the relevant system.

Since that paper was written, much work has been done to assess displaced emissions for specific resources or to assess methods of estimating displaced emissions. This work is summarized well by Martin Tampier in his paper for the CEC, *North American and International Initiatives to Quantify Emission Reductions from On-grid Renewable Electricity Facilities*. Most of the work summarized in this paper is geared toward developing methods of estimating emission reductions to be used for creating offsets or credits, or as part of a state emission-reduction plan. Moreover, there is broad interest in developing simplified methods for these purposes— that is, methods that do not rely on power system simulation models. The goal of this paper is to lay the groundwork for determining which simplified method can provide the best estimates of displaced emissions, and under what circumstances use of that method would be appropriate.

Section 2 of this paper examines several aspects of power system operation that are important to capture in displaced emission analyses. The concepts discussed in this section are then applied in Section 3, as we examine the most common simplified methods of estimating displacement.

Before proceeding, however, a note on terminology is warranted. First, the terms "operating margin," "build margin" and "combined margin" have begun to appear consistently in the literature on displaced emissions. Operating margin refers to the marginal plant operating in a regional power system over the short term—during a given hour or day. Build margin refers to the type of new plants that are likely to be added to a system over the medium to long term. Combined margin refers to a method of estimating displaced emissions, in which different marginal emission rates (such as an operating margin rate and a build margin rate) are used to estimate near-term and long-term displacement. It is important to note that, while these terms indicate that marginal emission rates are being used, they do not indicate how the marginal rates have been developed, and this is critical information.

Finally, throughout this paper we use the term "model" to refer only to a dynamic power system simulation model (e.g., a dispatch model or capacity expansion model). While other types of displaced emissions calculations are sometimes called models, it is useful to maintain a distinction between dynamic models and static methods based on data sorting and arithmetic.

[1] Keith, G., et. al., *Estimating the Emission Reduction Benefits of Renewable Electricity and Energy Efficiency in North America: Experience and Methods*, prepared by Synapse Energy Economics for the CEC, 22 September 2003, available at: <http://www.synapse-energy.com/publications.htm#papers>.

2 Important Aspects of Power System Operation

The operation and evolution of regional power systems is extremely complex, and so predicting how these systems will react to specific changes is naturally complex as well. The dynamics that affect emissions displacement most can be placed into three broad categories:

- Matching generation to load hour to hour;
- Transmission constraints and the available set of generating units; and
- Capacity additions and retirements.

The first two dynamics involve day-to-day system dispatch, and they affect assessments of the operating margin. The third deals with longer-term changes, and it is relevant in assessing the build margin. It is useful to note that dynamic power system models were developed precisely because it is very difficult to represent these aspects of power systems with a set of static assumptions. Thus, for any simplified method of displacement analysis, we must examine the assumptions made regarding these three dynamics and decide whether those assumptions represent the system well enough to produce credible results.[2]

2.1 Matching generation to load hour to hour

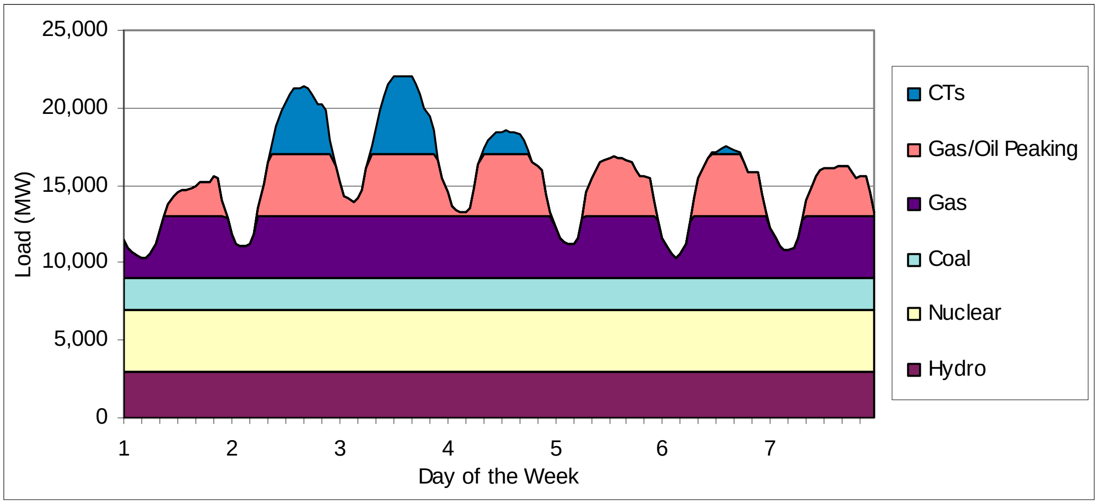
As we discussed in the 2003 paper, when a new resource is added to a regional power system, it typically affects the marginal generating unit(s) during the short term. This is because system operators dispatch generating units in economic merit order—that is, in order of increasing operating costs.[3] Thus, under most circumstances, if a new resource were available to dispatchers, it would effectively "shift up" all units above it in the dispatch order, reducing demand for the marginal unit(s). Thus, as a first order assumption, it is appropriate to use the emission rates of the marginal unit(s) to calculate emissions avoided by the new resource.

However, the assumption that a new project affects "the marginal unit" is not sufficient, because the new project is likely to operate in certain hours and not others, and because the marginal generating unit will be different at different hours of the day, week and year. Figure 1 is a highly simplified representation of plant dispatch in a hypothetical system during a typical summer week. Loads rise during the day and fall at night. The lowest cost generating units—baseload units—operate at full load around the clock. In our hypothetical system, these are hydro, nuclear and coal units. Higher-cost units operate in a more cyclic manner, increasing their output during the day and decreasing it during the night. In Figure 1 these are gas-fired units. More expensive gas- and oil-fired units are brought on line during the daytime when loads are highest, and combustion turbines are dispatched in the peak afternoon hours.

[2] Of course, the same questions should be asked about simulation models. That is, how well do the model's inputs and algorithms represent actual system operation? Simulation models have been widely applied in the electric power industry since the 1970s, and the models currently in use are widely accepted for planning and regulatory purposes, but the results can be sensitive to certain input assumptions. With the simplified methods discussed in this paper, there are additional and important concerns about whether the method itself is reasonably accurate.

[3] In a deregulated wholesale market administered by an Independent System Operator (e.g., PJM) the dispatch is based upon bid prices rather than operating costs, but if the market is reasonably competitive then this should amount to roughly the same thing for purposes of estimating displaced emissions.

Figure 1. Generating unit dispatch in a typical summer week



Note that different generating unit types are on the margin during different hours of the week. Further, the emission rates of the individual units within each category can vary significantly, putting many different emission rates on the margin. Couple these issues with the fact that any new resource we add to this system will have its own pattern of operation, and the question of displaced emissions begins to get quite complicated.

Now consider a new generating unit in this system that operates in a baseload manner. Regardless of exactly where in the baseload dispatch order this resource falls, it will effectively shift all resources above it *upward* in the dispatch order, reducing demand for the marginal unit in every hour. An energy efficiency program targeting baseload appliances would also reduce demand for the marginal unit in every hour. To estimate the emission impacts of new baseload resources, one would calculate the average emission rate of all the marginal units during this week, weighted by the number of hours that each unit was on the margin.

Next, consider a new solar generating unit added to this system. The operating cost of this resource would be quite low, so it would serve load whenever it was available, but it would only be available during the daytime. So the addition of this resource would shift all units in the stack upward during the daytime hours, displacing marginal generation during these hours only. To estimate the emissions impact of the new solar unit, one would use the weighted average marginal emission rate during the daytime hours. A dispatch model would reduce demand on the actual marginal unit(s) during each hour the solar unit operated, and it would reduce demand by the amount of solar generation provided in each hour. However, a reasonable estimate of the impacts could be made by applying a "summer daytime" marginal emission factor to the total summer output of the solar unit.

While these concepts may seem elementary, confusion persists in papers written about determining the benefits of renewable resources and energy efficiency. For example, it has been asserted that *small* new resources displace marginal units, but *large* new units displace baseload units. It has also been asserted that *intermittent* new resources displace marginal units, but *baseloaded* new resources displaced baseload units. In most situations a new resource reduces the generation from those units on the margin during the hours in which the new resource operates, and this is true regardless of the size or the generation profile of the new resource.

Thus, a key question in evaluating simplified methods for assessing displaced emissions is how well the method determines what generating units are on the margin during the hours that the new resource operates.

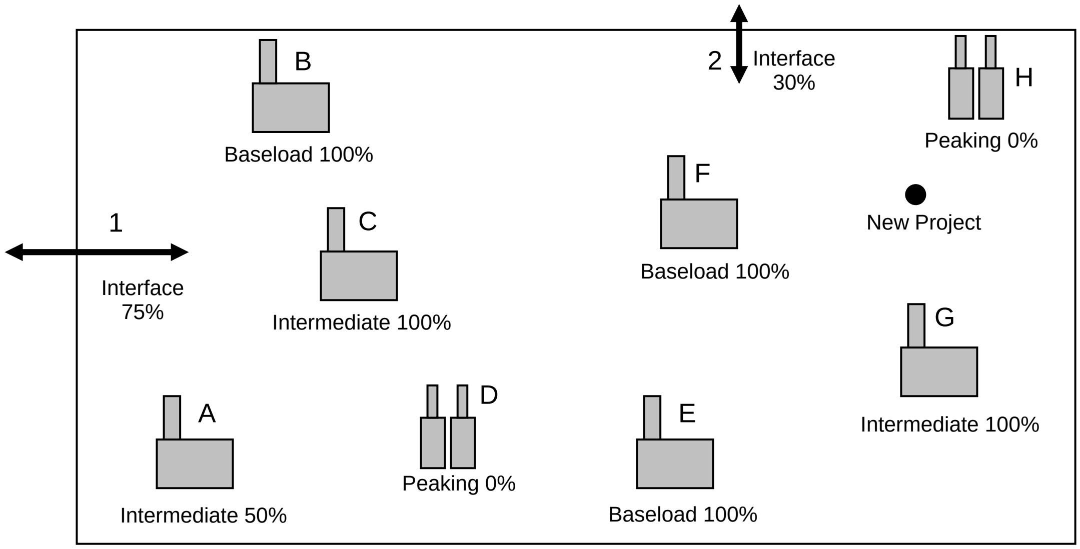
2.2 Transmission constraints and the available set of generating units

In addition to the relative operating costs of generating units, a key factor determining the marginal unit is the specific set of units available to system operators. This set of units changes hour to hour in response to several factors, but the most important factor by far is the availability of transmission capacity.

The national power systems in Canada, Mexico and the United States are divided into power control areas. Within a control area, plants are dispatched to meet load by a group of system operators, and these operators have available to them the generating units within the control area and, potentially, power imported from generators in other control areas. Transmission constraints within the control area affect the dispatch of plants within the area, and transmission constraints between control areas affect the availability of energy from other areas. For example, within a control area, if the ability to move energy into a city is limited, then units in that city may have to be dispatched “out of merit order.” That is, higher-cost units in the city must be operated, because energy from lower-cost units elsewhere cannot be delivered to the city. Examples of urban areas like this, often called “load pockets,” include New York City in the New York control area and southwestern Connecticut in the New England area.

As an illustration, assume that a new renewable energy project is under development at the location indicated in Figure 4. This figure depicts the operation of a very simple system at a particular point in time. The generating units shown represent the available units within the local control area, and the arrows labeled “interface” represent transmission lines connecting neighboring control areas. The percentage next to each asset shows the current loading of that asset, the percentage of its current capability that it is producing at the moment. The baseload units are the lowest cost; the intermediate units, higher cost; and the peaking units, highest.

Figure 4. Simplified representation of a power control area



It appears that the marginal unit in this system is either Intermediate Unit A or an out-of-region unit delivering energy over one of the two transmission interfaces. If the transmission interfaces were fully loaded, Unit A would probably be the marginal unit, but given the available transmission to other control areas, the marginal unit may be in one of those areas.

However, to determine which unit would be affected by the new project, we also need to know about the availability of transmission within the control area. For example, if transmission across the control area (east-west) is constrained, then the marginal unit affected by the new project is probably not Unit A or a unit delivering energy across Interface 1. It is probably energy from Interface 2 or from Unit G. If transmission is unconstrained within the control area, and additional energy from Interface 2 is expensive, then the project might affect Unit A.

Figure 4 does not depict a particularly unusual situation. System operators constantly wrestle with transmission constraints in keeping load and generation balanced. As a result, the set of units available to meet load at a given location is dynamic; it changes hourly, based largely on transmission constraints. Dispatch models are designed specifically to simulate transmission line loadings and their impacts on system dispatch, and their results reflect the constantly changing set of available units.[4]

In contrast to dispatch models, simplified methods of assessing displaced emissions rely on a fixed set of generating units. This set is usually defined as one or more control areas or NERC regions. This set of generators is almost certainly going to be the wrong set in certain hours of the year. It will be broader that the actual available set of units in some hours and smaller than the actual set in others. The best one can hope for is that the fixed set is wrong in very few hours per year. We will return to transmission issues in Section 3.3.2

[4] Different dispatch models represent transmission in different levels of detail. Most dispatch models contain at least a coarse representation of transmission between control areas, but only some models represent transmission within control areas well. This is an important issue when selecting a model for displaced emissions analysis.

2.3 Capacity additions and retirements

Most analysts agree that some estimate of the build margin should be used to estimate the long-term impacts of new resources. This is appropriate, as new generating units affect the evolution of power systems. That is, new plants affect the decisions of plant owners and other new plant developers. However, using the emission rate of a single new plant type may not reflect the dynamics involved very well. First, new plants affect decisions about plant retirements as well as plant additions. As new units displace the operation of older units, the owners of the older units make less money, and they must consider whether to retire or upgrade their unit. Second, as new units affect market entry decisions, the specific type of new unit makes a difference. Remember that power systems must maintain adequate baseload, intermediate and peaking capacity to meet load efficiently. When a new baseload resource is added, the system may still need peaking capacity in the near term; thus, while a new unit would contribute to deferring the next baseload unit, it might not affect the next new peaking unit.

As with short-term analyses, one could model these longer-term dynamics with a simulation model to determine the emission impacts of a new resource, or one could develop assumptions about the displaced plant types. With a capacity expansion model such as NEMS or IPM, the generation profile of the new resource would affect the timing and type of new capacity additions. Theoretically, the model would also capture the effect of the new resource on plant retirements. However, these models are notoriously poor at simulating plant retirements.

In developing assumptions to estimate displaced emissions over the long term, one should attempt to capture (1) the type of capacity the new resource is likely to affect, and (2) the effect the new resource will have on both plant additions and retirements. Regarding capacity type, it is usually sufficient to consider resources as either peaking or non-peaking resources for long-term displacement analysis, because many of today's new non-peaking resources are flexible enough to serve as either baseload or intermediate units. Thus, if the new resource will operate only during high load hours, it should be assumed to defer other peaking capacity additions. If the new resource will operate in a baseload, intermediate or intermittent way, it should generally be assumed to defer other non-peaking capacity additions. To include the unit's effect on retirements, one could either make a projection of retiring capacity based on the expected reserve margin in the region and an understanding of the economics of continued operation of older generating units, or use data on actual recent retirements in the region to develop a projection.

A non-modeling method would result in two long-term displaced emission factors, one for peaking units and one for non-peaking units, and each factor would be a weighted average of expected plant additions and retirements of that capacity type. So long as the capacity factor of the new clean resource is similar to the capacity factor the deferred resource would have had, it is reasonable to assume that energy is displaced on a one-to-one basis. If the capacity factors of the two resources are different, adjustments will need to be made to account for this.

Given the number of assumptions going into these factors, it seems prudent to have a single, qualified analyst review the relevant data and develop factors—which would undergo a peer review process—to be used by all projects in a given region for a specific time period. Depending on the resources available for this process, the analyst could also perform capacity expansion modeling to inform the process.

3 Non-modeling-based Methods of Estimating Displaced Emissions

As noted, there is considerable interest in developing methods of estimating displaced emissions that do not rely on dispatch modeling. In this section we examine three non-modeling-based approaches to estimating near-term displacement. That is, these methods seek to identify the emission rates of the *operating margin* and apply these rates to potential new projects. One of these methods seeks to identify marginal units by geography, another by unit type and the third, using a load curve analysis. In assessing these methods, we will refer back to the aspects of power system operation discussed in Section 2.

3.1 Defining the marginal units by geography

At least one recent paper has attempted to go beyond the use of a simple system average emission rate by averaging the emission rates of a geographically defined set of units. The National Renewable Energy Laboratory (NREL) has released a draft study comparing several methods of estimating emissions displaced by specific energy efficiency programs, titled *Comparison of Different Methods for Developing NOx Emission Factors for Assessing EE Projects in Shreveport, Louisiana*. The paper reviews simplified methods of estimating displacement with an eye toward establishing a method for including emission reductions from electric sector projects in State Implementation Plans (SIPs).[5] The paper is in draft form and currently out for comment.

One of the methods examined in this paper calculates the average emission rate of various subsets of US power plants. The subsets are defined by geography and, in some cases, by generating unit ownership. The largest set of units averaged includes all the units in the US for which EPA releases emissions data (in the EGRID database). The smallest geographic region examined includes only two plants within Caddo Parish, Louisiana, the parish in which the efficiency program will be implemented. Averages are also calculated for a number of regions that fall between these two regions in size.

The average ozone-season NO_x rates from the units in the regions assessed range from 0.88 kg per MWh (1.95 lbs per MWh) for the two gas-fired plants in Caddo Parish to 2.10 kg per MWh (4.63 lbs per MWh) for the units owned by American Electric Power Co. in Louisiana. Using each of these emission rates, the Shreveport efficiency project could displace either 8.1 or 19.2 metric tonnes per year of NO_x.[6] The authors conclude that this methodology provides an adequate level of detail for calculating the emission benefits of efficiency projects saving up to 500 MWh per day, or roughly 75,000 MWh during the summer ozone season.

We disagree with this conclusion. This method does not attempt to discern which generating units are on the margin during the hours that the efficiency project saves energy. In fact, the method does not attempt to discern the operating characteristics of any of the generating units involved. The method defines the displaced unit based on geography and, to a lesser extent, plant ownership. As discussed in Section 2.2, a generating unit's location tells us little about if and

[5] A SIP is a plan developed by air regulators in the US to bring a specific region into compliance with a National Ambient Air Quality Standard.

[6] The figures cited in the NREL paper are 8.89 to 21.12 short tons of NO_x per year.

when the unit is likely to be on the marginal. (Plant ownership tells us nothing about plant operation either.) To see the flaw in this method, consider that the three AEP units comprising the high emission rate (2.10 kg per MWh) may be low-cost baseload units that operate at full load whenever they are available, and would do so even if the new unit or incremental efficiency measures were added to the system. If this were the case, reduced demand anywhere in Louisiana would not be expected to affect these units.

Thus, while using a system average emission rate to estimate emissions displacement is inappropriate, defining a subset of units based on geography alone is likely to be equally misleading.

3.2 Defining the marginal units by type

Several papers have also been circulated that define the marginal generating based on unit type. These papers have typically assumed that "peaking" units or "load following" units are displaced by new projects. However, as discussed in Section 2.1, many different types of generating unit can be on the margin, especially across different control areas and time periods. Furthermore, the emission rates within a given category of units may vary considerably. Thus, unless an analysis of a particular new resource and power system indicates that a specific resource type will be displaced, the use of a unit type should be avoided.

The term "peaking unit" typically refers to a simple-cycle gas turbine that can be started quickly to meet peak loads. These units are usually less efficient than large combined-cycle or even steam-electric power plants and considerably more expensive to operate. To see why the assumption that peaking turbines are marginal can be wrong, refer back to Figure 1. In this hypothetical system, peaking turbines are on the margin only during the peak hours of the afternoon. During the other hours of this week, other high-cost units are on the margin, and the emission rates of these units would be similar to those of the peaking units only by chance. During lower-load seasons in this hypothetical region, peaking units may never be on the margin.

Of course, analysis of a specific set of circumstances may lead the analyst to conclude that a new resource will affect peaking units during most hours of its operation. In the paper, *Summer 2001 NEPOOL Load Response Program: Emissions Impacts and Associated Discussions*, Environmental Futures Inc. uses peaking turbines to characterize displaced emissions based on a determination that load response programs are only triggered during periods of very high loads, when peaking turbines are typically on the margin in New England. This is an appropriate first-order assumption. However, without an analysis of the specific resource and power system in question, assuming that peaking turbines are displaced will often lead to errors.

A study by Resource Systems Group for the Clipper Wind project in Maryland assumed that "load-following" units are displaced by the wind project. This study, titled Prospective Environmental Report for Clipper Wind Power, reports that a list of load-following units was provided by "load-serving entities" in the PJM area. The research conducted to support this assumption is not fully clear, but there are two potential problems with it. First, the term "load-following" unit can be used to describe different kinds of generating unit, and it is not clear exactly how the term was defined for this project. Furthermore, "load-serving entities" (entities that sell electricity at retail) do not typically have comprehensive data on the operation of power plants. System operators are likely to be the only group with this information, and confidentiality rules typically prevent them from releasing it. Second, it is not clear whether research was done to determine whether the units defined as "load-following" units would actually be displaced by the new wind project.

The term "load-following" usually refers to units that vary their output frequently during the day to allow the system to increase and decrease total output smoothly and to respond to short-term fluctuations in demand. Some of these units are controlled directly by system operators, and these units are used to meet very short-term fluctuations in demand (e.g., second-to-second fluctuations). These load-following units are usually on automatic generation control, or "AGC." Other units often referred to as load-following units are controlled by the on-site plant operators, but the units are able to change loading levels rapidly to meet hour-to-hour changes in demand. During the course of a year, the group of generating units providing load-following services in a given region can change as the region's load-following needs change.

Thus, load-following units (1) allow system operators to keep total system output stable as generating units are started and stopped and (2) react to short-term fluctuations in demand that are impossible to predict. Once a new resource is available, system operators enter it into the software that optimizes system dispatch. Typically, this process takes place on a day-ahead basis so that plant operators have sufficient time to prepare. Hence, there is ample time to factor in the expected operation of the new resource. With the new resource, the system will still have to match loads smoothly as loads rise and fall, and it will have to handle unexpected changes in demand. Therefore, while the addition of the new resource may change the pattern of load-following generation slightly, it will not change it in a predictable or systematic way. (The new resource may in fact result in more or less load-following generation.) In contrast, a new resource's effect on marginal generation is both predictable and systematic.

Highly unpredictable resources are likely to impact load-following resources more than predictable ones. We use the term "unpredictable" rather than intermittent, because the operation of many intermittent resources is largely predictable. Methods of predicting solar and wind generation, for example, have improved considerably over the past decade. Further, systems with geographically diverse wind resources can make very reliable predictions of total wind production, because fluctuations in output at each site are averaged. In cases where intermittent resources are predictable, a marginal emission factor is more appropriate than a load-following emission factor. More research is needed to determine whether some resources are unpredictable enough to affect primarily load following resources.

3.3 Defining the marginal units using a load curve analysis

The simplified method that has received the most attention recently calculates a weighted average marginal emission rate by analyzing generating units in the context of a load duration curve. Two studies using this method have been published by PA Consulting and Lawrence Berkeley National Laboratory,[7] and a number of other unpublished papers using the method have

[7] See: Erickson, Jeff, et al., *Estimating Seasonal and Peak Environmental Emission Factors – Final Report*, for the State of Wisconsin Department of Administration, Division of Energy, 21 May 2004, and Meyers, S., et al.,

been circulated. A load curve analysis is likely to generate accurate results in more situations than the methods discussed in the previous two sections, but more work is needed to determine whether this method is accurate enough to adopt as a standardized approach to be used in a wide variety of situations.

A load duration curve is a representation of the hourly loads in a region ordered from highest to lowest rather than chronologically. For example, Figure 1, above, shows the chronological, hourly loads in a hypothetical system during a typical summer week. If we reorder those same hourly loads from highest to lowest, the result is the descending line shown in Figure 5.

Figure 5. Load duration curve for a typical summer week

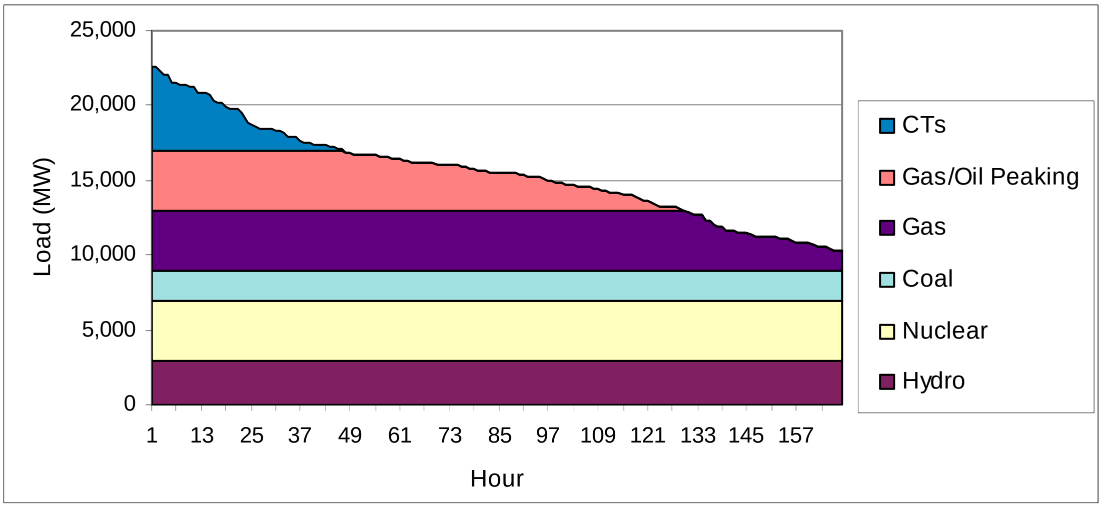


Figure 5 also shows the same hypothetical pattern of generating unit dispatch shown in Figure 1. By comparing unit generation to the load curve in this way, we get a good estimate of when different unit types were on the margin. The CTs appear to have been on the margin for about 49 hours of this week. Using these data, we could calculate a weighted average NO_x factor, for example, by averaging the emission rates of the three marginal unit types, weighted by the number of hours each one was on the margin. With the data shown, we would have to use average emission rates for each unit type, but if we had unit-level data, we could calculate a weighted average of the unit's emission rates. If there were considerable variation in the emission rates within each unit type, this would be a much better approach. (Note that in this example some of the "Gas" units are never on the margin.)

This method is superior to the methods discussed in the previous two sections in two ways. First, it attempts to develop marginal emission rates that reflect the actual utilization of the generating units in the region. Second, by selecting subsets of an annual data set (like the hypothetical week shown above), the method could be used to develop weighted average marginal emission rates for specific time periods, such as the summer peak hours, summer off-peak hours, etc. These emission factors could then be applied to new projects based on each project's expected generation profile.

The analysis below focuses on two aspects of the load curve method. First, data must be adjusted in order to fit the generating plants under the load curve, and second, the method ignores the impact of transmission constraints on unit dispatch. The adjustments to data need not compromise the accuracy of this method if they are made properly. Ignoring transmission, however, could influence results significantly, and more work is needed to determine how robust this method is in light of this limitation.

3.3.1 Ordering generating units under the load curve

As seen in Figure 5, the generating units within a power system must be layered under the load curve in the order in which they are typically dispatched to estimate which ones were on the margin and for how many hours. There are several challenges in this process. First, one must develop a method of stacking the units that accounts for unit outages and for power purchases from neighboring regions. Second, one must adjust the capacities of generating units in the bid stack to make it consistent with the actual load curve.

There are two ways to order units under a load curve: ordering based on historical utilization and ordering based on operating costs. To order units based on utilization, one would use historical generation data to calculate each unit's capacity factor, and then stack the units from highest capacity factor (on the bottom) to lowest capacity factor (on the top). This would represent the units that operated the most as being dispatched first on any given day, and the units that operated least as being dispatched last. However, the actual outages experienced at the units during the data year being used would cause a number of units to be misplaced in this stack. Generating units are "down" (i.e., unavailable) periodically for planned and unplanned maintenance work. These outages reduce a unit's capacity factor, because no energy is being generated during the outage. Thus a nuclear unit that was off-line for much of a year would have a relatively low capacity factor, but this method of stacking units would place it high in the dispatch order, potentially on the margin during some hours. This is wrong, as nuclear units are typically operated as baseload resources during all hours that they are available.

Therefore, in order to stack units by capacity factor properly, one must adjust the generation data to account for outages.[8] This issue is especially important when calculating seasonal emission factors rather annual ones, because a maintenance outage at a baseload unit could cover a very large portion of a season, giving that unit a very low capacity factor for the season.

The second way to order generating units under the curve is by operating costs—either estimated or actual historical costs. Using estimated operating costs may lead to a large margin of error, because it could be difficult to differentiate the operating costs of generating units of a given type. That is, how does one know if one coal-fired plant costs more to run than another? Using

[8] There are several ways of doing this. First, one could simply remove the outage hours from the capacity factor calculation. The resulting figure, called a "utilization rate," would reflect each unit's operation during the hours that it was available. Second, one could review generation data from a number of historical years and use each unit's average capacity factor over the years to locate it in the dispatch order.

actual operating costs (which plant owners have reported to government agencies) may provide more detail in the bid stack, but it is likely to be labor intensive to collect and check the data. The key advantage to stacking units by operating costs is that it avoids the task of adjusting capacity factors for outages.

Regardless of whether one orders units by historical utilization or operating costs, one will have to fit energy purchased from neighboring regions somewhere in the bid stack and develop emission rates for this energy. Actual power purchases will have to be analyzed to determine whether they were effectively baseload, intermediate or peaking resources, and one will have to determine the likely sources of the energy to apply emission rates to purchased power.

Finally, after ordering the generating units and purchases to represent typical dispatch, one must adjust each unit's capacity in the "bid stack" in order to fit the resources appropriately under actual load data. System operators rarely have all of the installed capacity in the region at their disposal, because several generating units are usually down for maintenance or on forced outage at any given time. It would not work to include all the region's units in a load curve analysis at their full ("nameplate" or "net dependable capability") capacities, because there would be generation in excess of the actual loads. So unit capacities must be lowered, or adjusted to account for outages, and this process requires some judgment on the part of the analyst. For example, one might consider calculating each unit's average output level during the summer peak hours, and using these figures for units' maximum capacities under the summer peak load curve. However, it is unlikely that this approach would result in exactly the right amount of capacity in the highest load hours.

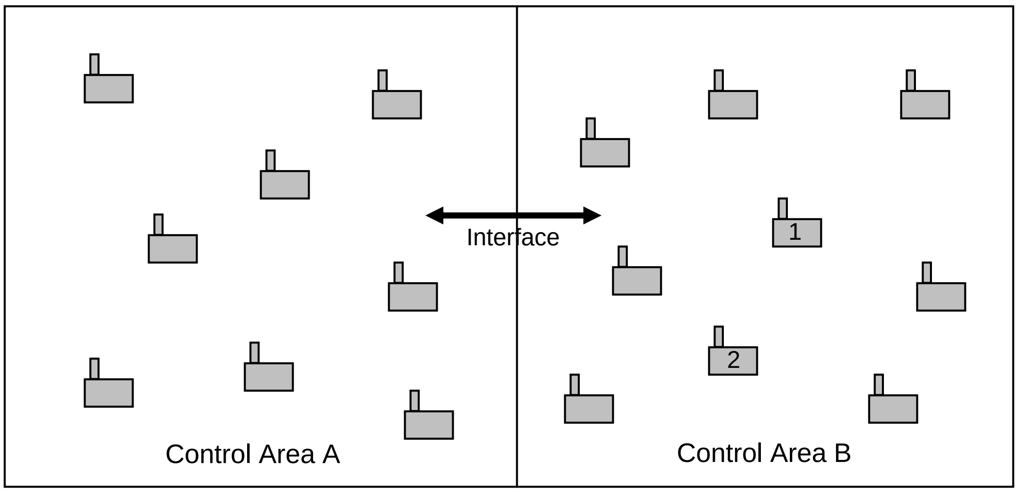
In fact, if one is using actual load data and actual generation data, there is no way to back out the "right" capacity figures because the system is overdetermined. That is, during the period being assessed, the set of available units changed and the capacities of specific units may have changed also. Using actual data on loads and generation, the only way to "solve" for these variables would be to recreate the hourly dispatch of the system. That way the capacity of the system in each hour would meet the actual load in each hour. Thus, the analyst will have to approximate a capacity for each unit under the load curve that represents the system in a way consistent with the actual generation and load data.

Finally, it is critical to ensure that the data year being used is representative of typical unit operation in the region being assessed. If the data are atypical, then adjustments should be made in order to estimate near-term displaced emissions under typical conditions. Further, if the data being used are several years old, it will be important to adjust them to reflect any unit additions or retirements that have occurred in the region.

3.3.2 Transmission constraints affect unit dispatch

The load curve approach deals with a fixed, geographically defined set of generating units. As discussed in Section 2.2, any fixed set of units is almost certain to be too large in some hours and too small in others. To see this in another way, consider the two control areas in Figure 6. Assume that, in many hours, the marginal unit in Control Area A is within that area, but in some hours it is Unit 1 in Area B and in other hours it is Unit 2 in Area B. If one were to calculate a weighted average marginal emission factor for Area A using just the units in Area A, this factor would miss the contribution of Units 1 and 2 in Area B. However, if one were to develop a load curve for both areas combined as one, and stack all the units in both areas under that curve, then many other units from Area B would appear on the margin when these units were not actually affected by load in Area A. That is, ignoring the transmission constraint and summing both areas would create a fictional supply curve, one that was not available to either set of system operators.

Figure 6. Marginal Units in a Neighboring Control Area



To assess whether this issue is likely to be a problem, one might simply check the amount of energy actually moving between control areas in the region of interest, hoping that there is little exchange and that analysis of a single control area would be reasonable. However, recall from Section 2.2 that *this issue can also be a problem within a control area.* Transmission constraints within a control area can cause many generating units to be unavailable to certain loads for extended periods of time. In these cases, the marginal unit serving load in the constrained area is not the marginal unit for the control area at large, but the marginal unit *available to the load pocket*. Analysis of a load curve would miss this.

For example, consider an energy efficiency program implemented in southwest Connecticut. There are likely to be a significant number of heavy load hours in which transmission into the load pocket is fully loaded and the displaced generating units will be in southwest Connecticut, but there will also be many lower load hours in which the transmission is not fully loaded and the displaced generating units could be anywhere in the NEPOOL system (or beyond). To get a sense of whether and to what extent transmission constraints might figure into displaced emissions calculations in any particular situation, one might examine data on: (1) how often the transmission constraint causes dispatch out of merit order, (2) how often the intertie is fully loaded, and (3) the emission profiles of the smaller and larger geographic regions.[9]

The frequency of transmission constraints causing dispatch out of merit order has increased considerably in the US over the past decade, as the pace of load growth and generating capacity

[9] If the emission rates are similar in the smaller and larger geographic regions, then perhaps even a transmission constraint that is very important for system dispatch may not be critical to a displaced emissions calculation, and a load curve-filling method might be acceptable.

development has been far faster than the pace of new transmission development. And this trend may continue. In this context, the fact that load curve analyses ignore the effects of transmission on dispatch may be a significant drawback to this approach. More work is needed to understand exactly how accurate this method is in both areas with ample transmission capacity and tight capacity.

4 Summary and Conclusions

We began by examining three aspects of power system operation and development that are critical for determining the emission impacts of new resources. These three aspects are:

- Matching generation to load hour to hour;
- Transmission constraints and the available set of generating units; and
- Capacity additions and retirements.

The first two aspects involve day-to-day system dispatch, and they determine which generating unit or units are on the margin, and thus which units are likely to be affected by a new unit or reduced load. The third aspect deals with longer-term changes in a power system, and it determines the long-term emission impacts of a new resource.

Next, we examined the three simplified (i.e., non-modeling-based) methods of estimating emission displacement, which are most commonly described in the literature. These methods are distinct primarily in the way that they seek to identify the marginal generating unit in the relevant system—the unit likely to be affected by a new project. One method identifies this unit based on geography; the second identifies it based on unit type; and the third, based on a load curve analysis. We conclude that the first two methods are not likely to yield accurate results, because they cannot reliably identify the marginal generating unit(s). The third method—the load curve analysis— is potentially far superior to the other methods. However, a number of adjustments and assumptions must be made in this method, and the method ignores the impact of transmission constraints on generating unit dispatch. More work is needed to determine how robust this method is.