Chapter 21. Change the Dispatch Order of Power Plants

1. Profile

One option for reducing carbon dioxide (CO_2) emissions in the power sector is to change the order in which power plants are dispatched, so lower emitting power plants operate more frequently and higher emitting power plants operate less frequently. A number of different policies can accomplish this goal. Before explaining those policy options, we will first explain the status quo approach to dispatch.

Because large batteries and pumped storage dams are currently expensive, electricity generally cannot be stored economically. The supply of electric energy from power plants must be in balance at all times with the demand for electricity from consumers, accounting for losses in the transmission and distribution system.[1] This requires sophisticated control of power plants and transmission lines to provide reliable service.

The North American power system or grid is divided into dozens of balancing areas (also known as control areas). Within each balancing area, supply and demand are kept in balance by an entity called a balancing authority, who issues dispatch orders to power plant operators to turn on a generator, ramp its output up or down, or turn it off.

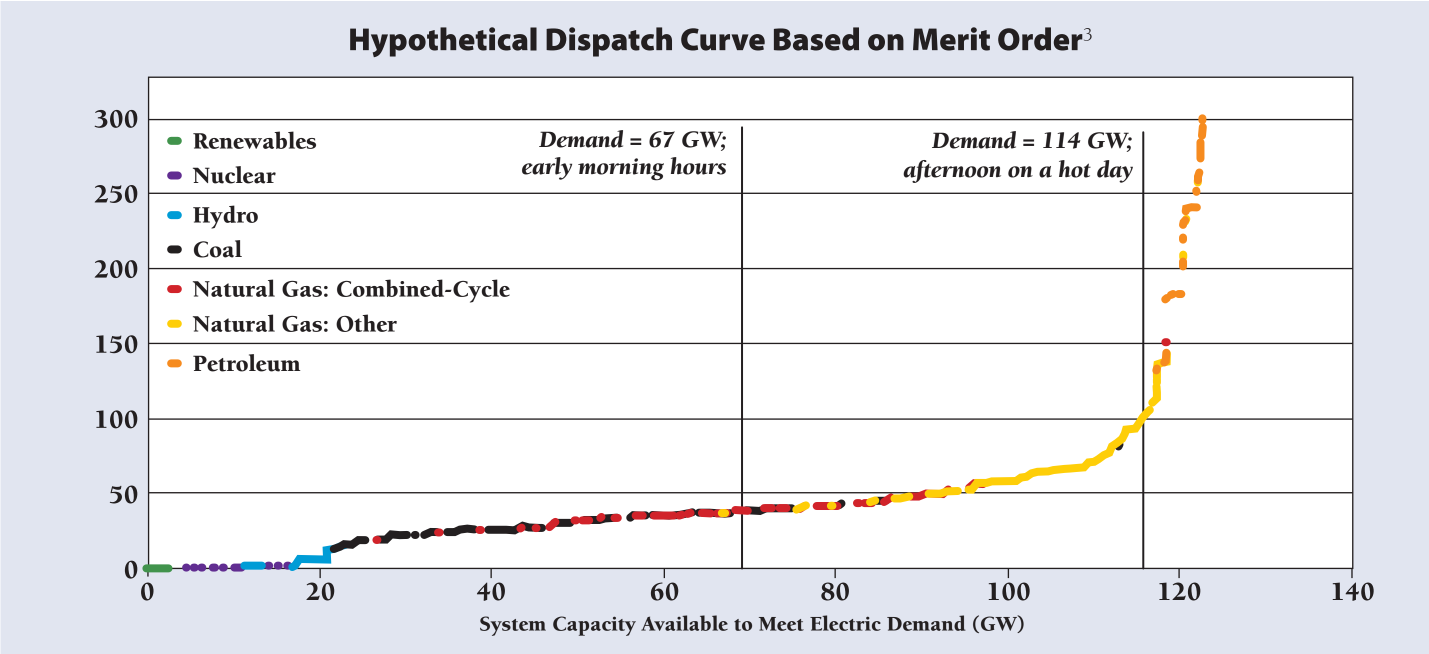
The role of a balancing authority is filled by different types of entities in different parts of the country. In some places, balancing is done by a vertically integrated utility that owns generation (i.e., power plants), transmission, and distribution system assets. These utilities control the dispatch of their own power plants and those of independent power producers (IPPs) that are connected to their system, and they are required by law to provide nondiscriminatory access to IPPs. In many other places, utilities have voluntarily agreed to cede this balancing authority to an independent system operator (ISO) or regional transmission organization (RTO) that oversees a competitive market for the wholesale generation of electricity by utilities and IPPs. Lastly, there are parts of the country where a federal power marketing agency serves as the balancing authority, controlling the output of federal hydropower projects and the output of power plants owned by utilities or IPPs.

Regardless of who does the balancing, an approach known as "security-constrained economic dispatch" is the norm for controlling power plant output. First, the system operator identifies the generating capabilities and the variable operating costs of all of the available electric generating units (EGUs). The capabilities of interest for each EGU include its maximum and minimum generation levels, ramp rate (how quickly its output can be changed up or down), minimum notification time for startup, minimum amount of time it must run once started, and minimum amount of time it must stay off once switched off.[2] In addition, some EGUs might have operating restrictions associated with air pollution control permits or other regulatory approvals. Variable operating costs include all of the categories of costs that vary depending on whether and at what capacity the EGU is operated, including startup costs. The biggest category of variable costs for fossil-fueled EGUs is the cost of fuel. Environmental compliance costs are included to the extent that they are variable, but externalities such as the social cost of carbon would not be included because the generator does not have an associated compliance cost. Capital costs, such as the costs of constructing the EGU or its pollution control equipment, are not variable and would

1 When supply and demand (plus losses) are not in balance, the frequency of delivered power will increase above or decrease below the design frequency. Most equipment can handle very narrow deviations from electrical specifications, and thus the supply and demand do not need to be *exactly* equal at all times. But if the changes in frequency go beyond those narrow tolerances, this can damage electrical equipment or cause system failure.

2 This explanation of economic dispatch is adapted from: Federal Energy Regulatory Commission Staff. (2005, November). *Economic Dispatch: Concepts, Practices, and Issues.* Available at: http://www.ferc.gov/eventcalendar/Files/20051110172953-FERC%20Staff%20Presentation.pdf.

Figure 21-1



also be excluded. In areas governed by an ISO or RTO, operating costs are revealed through competitive bids made by generators.

With all of the information on capabilities and costs in hand, the system operator then ranks the available EGUs in merit order from the least costly to the most costly, as depicted in Figure 21-1.

Ideally the system operator would want to minimize the costs of meeting electric demand by scheduling EGUs for dispatch based on merit order. The least costly EGU would be scheduled first, and then the next least costly EGU, and so forth until enough generation was scheduled to meet the expected demand. This concept is shown in Figure 21-1 for two different hypothetical demand levels.[4] However, before the system operator actually schedules the dispatch of any EGUs, he or she will complete a reliability assessment that considers, among other key factors, the capabilities of the transmission system.

Based on the reliability assessment, system operators sometimes must deviate from merit order dispatch. One of the more common reasons this can happen is because of security constraints. For example, there can be cases in which a more expensive EGU is dispatched to meet load and ensure reliability in a specific geographic area because there is inadequate transmission capacity to deliver less expensive power from an EGU located outside the area. Another reason an EGU might be temporarily operated out of merit order is that the EGU is economical to dispatch in almost all hours, but does not have the flexibility to ramp down for a few hours and then ramp back up when it merits its dispatch. For example, this may happen in the case of nuclear power plants.[5]

Although EGUs are sometimes dispatched out of merit order, merit order itself is a purely economic consideration. The emissions that result from the dispatch of any particular EGU are only considered to the extent that there

3 US Energy Information Administration. (2012, August). *Today in Energy.* Available at: http://www.eia.gov/todayinenergy/images/2012.08.17/DispatchCurve.png.

4 The description here mostly describes day-ahead scheduling of EGUs to meet forecasted demand. System operators make similar decisions in hour-ahead scheduling adjustments and real-time balancing decisions based on actual demand, except that the capabilities most needed in those shorter time frames can be different (e.g., ramp rate can be more important), and the variable costs can be different (e.g., if a unit is already operating, its startup costs are not part of its variable costs over the next hour).

5 There are a variety of other reasons EGUs might be dispatched out of merit order. Those reasons can be extremely important for ensuring reliable operation of the system, but are generally beyond the scope of this chapter and need not be explained to understand the potential to reduce CO_2 emissions by changing dispatch order.

is a variable regulatory compliance cost associated with emissions. Fortunately, many of the renewable technologies that produce no emissions also have no fuel costs and near-zero variable operating costs. Nuclear EGUs also tend to have very low variable operating costs, because their fuel costs are considerably less than those of fossil-fueled EGUs. Consequently, renewable and nuclear EGUs generally rank very high on merit order and tend to be among the first EGUs dispatched by the system operator, as shown in the hypothetical dispatch curve in Figure 21-1. However, after those options are exhausted, if more supply is still needed to meet demand, we find that the least-cost EGUs are not always the lowest emitting EGUs. For example, in the hypothetical dispatch curve, we see that coal-fired units have lower variable costs than gas-fired units, but we know that the coal-fired units also have approximately double the CO_2 emissions of gas-fired units. In other words, emissions could be reduced (at some economic cost) if the dispatch order were changed.

There are several ways to address this issue and change the order in which power plants are dispatched. In some jurisdictions, emissions pricing policies are in place for CO_2. These policies include emissions taxes or, more commonly in the United States, emissions trading programs that directly or indirectly place a price on emissions.[6] If an EGU must pay a tax on each ton of CO_2 emissions, or must obtain an allowance for each ton, this regulatory requirement is "internalized" and adds to the EGU's variable operating costs. This, in turn, leads to lower emitting EGUs ranking higher in the merit order and being dispatched earlier and operating for more hours. Putting such emissions pricing policies in place in more jurisdictions is thus an effective way to reduce CO_2 emissions from power plants.

The electric cooperative Great River Energy and the consulting firm Brattle Group have proposed a variation on emissions pricing in response to the Clean Power Plan that the Environmental Protection Agency (EPA) proposed in June 2014 to regulate CO_2 emissions from existing power plants. Great River Energy operates within the Midcontinent ISO (MISO), where MISO uses security-constrained economic dispatch based on competitive bids made by EGUs. The cooperative has proposed that the MISO could impose a CO_2 emissions price on EGUs under its control. The price would be determined based on simulation models, and set at whatever level would be necessary to change dispatch order enough to ensure compliance with Clean Power Plan regulations across the system.[7]

An alternative to emissions pricing that also shifts the dispatch order toward lower emitting EGUs is called "environmental dispatch." Environmental dispatch is a policy in which the system operator explicitly considers environmental criteria (primarily air emissions) when making dispatch decisions, *even if the environmental impacts do not lead to an actual regulatory compliance cost.* EGUs that have lower environmental impacts can potentially be operated out of economic merit order. There are many possible scenarios under which environmental dispatch could be implemented, and the scenarios vary based on which variable(s) are being emphasized. For example, some of the possible approaches to environmental dispatch include:

- Preferentially dispatching certain resources first;
- Imputing a cost adder (dollars per megawatt-hour [MWh]) in the variable costs of fossil-fuel EGUs to account for environmental and public health externalities; and
- Optimizing dispatch for one variable, such as heat rate or CO_2.

Dispatching resources based on heat-rate (British thermal units [BTUs] per kilowatt-hour [kWh]) could be a relatively straightforward way to introduce environmental dispatch, because there is a good correlation between those units that consume the least fuel to generate electricity and those with the lowest CO_2 emissions.[8]

6 Cap-and-trade programs are described in more detail in Chapter 24, and carbon taxes are described in more detail in Chapter 25.

7 Chang, J., Weiss, J., & Yang, Y. (2014, April). *A Market-Based Regional Approach to Valuing and Reducing GHG Emissions from Power Sector: An ISO-Administered Carbon Price as a Compliance Option for EPA's Existing Source Rule.* Discussion paper prepared by Brattle Group for Great River Energy. Available at: http://www.brattle.com/system/news/pdfs/000/000/616/original/A_Market-based_Regional_Approach_to_Valuing_and_Reducing_GHG_Emissions_from_Power_Sector.pdf?1397501081.

8 Minimizing a unit's heat rate is one of the mechanisms the EPA has evaluated to determine the degree of greenhouse gas emissions improvement that is possible. Assuring that a unit operates at the lowest heat rate for its boiler type and fuel also helps to reduce fuel costs for the generator.

2. Regulatory Backdrop

Economic dispatch based on merit order is the norm in the United States. The regulatory basis for this norm can be found in federal and state energy policies.

To begin with, in the case of state regulated, vertically integrated electric utilities, the principle of "prudency" is important to understand. Utilities are allowed to recover the cost of prudently incurred expenses in the rates that they charge to retail customers. But if a utility is paying more than is necessary to serve customer demand while complying with all applicable regulations, and considering security constraints, the additional costs (in theory) will be deemed imprudent and the utility will not be able to recover those costs. Therefore, any deviation from economic dispatch based on variable operating costs (which includes variable regulatory compliance costs) puts the utility at risk for losing money.

In areas where utilities have voluntarily formed an ISO or RTO, the ISO/RTO must establish market rules that are subject to approval by the Federal Energy Regulatory Commission. These market rules are intended to ensure that wholesale generation and transmission costs are minimized and that the market cannot be manipulated by any party. Generators must make bids to the ISO/RTO based on their variable operating costs if they are available for dispatch, and the ISO/RTO must dispatch generation based on the principle of security-constrained economic dispatch.

In both of the above cases, transmission owners and operators (utilities, ISOs, and RTOs) are also required by federal law to provide nondiscriminatory and open access to all generators. They cannot favor certain types of generators (e.g., lower emitting generators) over others.

Under the current regime of federal and state energy policies, the first of the options listed in the preceding section (preferentially dispatching certain resources first) thus may not be feasible. Changing the dispatch order of power plants might only be possible where it is done in response to a regulatory requirement that imposes either an explicit variable operating cost (e.g., through a carbon tax), a market-based variable operating cost (e.g., through a cap-and-trade program), or an imputed variable operating cost (e.g., where a vertically integrated utility can show that dispatching power plants out of merit order is prudent because it costs less than other alternatives for complying with a regulation). Optimizing dispatch based on one variable might be possible if it is similarly in response to a regulatory requirement, even if a cost adder is not involved. In any event, changes to wholesale energy market rules for an ISO/RTO would have to be approved by the Federal Energy Regulatory Commission.

Changing dispatch order is a central component of the emissions guidelines for CO_2 emissions from existing power plants that the EPA proposed on June 2, 2014 (a.k.a. the Clean Power Plan). The EPA determined that the best system of emission reduction for existing power plants is one that comprises a combination of four building blocks determined to have been adequately demonstrated to reduce CO_2 emissions, with due consideration for impacts on the cost of electricity and electricity system reliability. One of those four building blocks consists of increasing the use of low emitting, natural gas-fired combined-cycle (NGCC) EGUs. Although the proposed regulation would not require states to change the dispatch order of power plants, the emissions targets that the EPA proposed for each state are based in part on the EPA's assumption that dispatch can be shifted from coal-, oil-, and gas-fired steam EGUs to NGCC EGUs up to the point at which the NGCC EGUs are operating at an annual average of 70 percent of rated capacity. The impact of this building block on the state goals is variable and depends on the amount of installed combined-cycle capacity and the historic amount of steam EGU generation. In some states, the assumption is that literally all of the steam EGU generation could be re-dispatched to combined-cycle EGUs. However, the EPA did not specify how states would implement or enforce a change in dispatch order in view of the regulatory limitations discussed previously.

It is perhaps worth mentioning here that several states have enacted a loading order policy that is similar in some respects to an environmental dispatch policy, but also has key differences. Loading order policies regulate the procurement of energy resources by utilities, and explicitly favor low emitting resources over higher emitting resources. However, these policies are limited in scope to the construction of new power plants by utilities or the acquisition of energy through contractual arrangements with IPPs. The day-to-day dispatch of these resources is not affected in the way that it would be under an environmental dispatch policy. Loading order policies are also described in Chapter 16.

3. State and Local Implementation Experiences

In this chapter, we have explained how the merit order concept is based on variable operating costs, including variable regulatory compliance costs. In a certain sense, virtually all of the states have experience with changing the dispatch order of power plants to reduce emissions because regulatory compliance costs are ubiquitous. For example, EGUs regulated under the Acid Rain Program can be found in 48 states. And looking specifically at CO_2 emissions, we see examples of cap-and-trade programs affecting EGUs in nine northeastern states and in California. The variable costs of complying with the Acid Rain Program and complying with regional CO_2 cap-and-trade programs already factor into dispatch decisions in those jurisdictions.[9]

Other than emissions trading policies that indirectly impose a variable regulatory compliance cost on EGUs, there are relatively few examples of policies in the United States that are designed to change the dispatch order of power plants to reduce emissions. Examples from other countries, including China, may offer further insights into this approach.

California has had a loading order policy since 2004. To implement the policy, the California Public Utilities Commission requires investor-owned utilities to include a

The California Public Utilities Commission ordered utilities to include an imputed dollar-per-ton cost adder for CO_2 emissions when evaluating resources to procure. Table 21-1 provides an example of how this cost adder contributes to variable operating costs for two types of EGUs.

In this example, although both units use natural gas as a fuel, their heat rates differ: 7 million BTU per MWh (MMBtu/MWh) for the combined-cycle plant, versus 11 MMBtu/MWh for the combustion turbine. The heat rate difference affects their emissions rates, which are 819 pounds of CO_2/MWh for the combined-cycle plant, versus 1287 pounds of CO_2/MWh for the combustion turbine. Likewise, the heat rate also affects emissions costs, which end up being $4/MWh for the combined-cycle EGU, and $6/MWh for the combustion turbine.

California used this approach in the context of making resource procurement decisions rather than dispatch decisions. But if California wished to implement environmental dispatch to optimize CO_2 emissions, the same CO_2 price adders (of $4 and $6 per MWh, respectively) could be added to the fuel costs, resulting in an imputed variable operating cost of $39 per MWh for the combined-cycle plant and $61 per MWh for the combustion turbine. Examples could be similarly derived for all of the available generating options, and these imputed costs could be used in lieu of actual variable operating costs in making dispatch decisions.

Table 21-1

Example of Imputed Cost Adder for CO_2 Emissions[10]

Factor	Units	Formula	Combined-Cycle Plant	Combustion Turbine
Gas Price	$/MMBtu		$5	$5
CO_2 Price	$/ton		$10	$10
CO_2 Price	$/lb	(=10/2000)	$0.005	$0.005
Emissions Factor	lbs/MMBtu		117	117
Heat Rate	MMBtu/MWh		7	11
Emission Rate	lbs/MWh	(=Emissions Factor x Heat Rate)	819	1287
Emissions Cost	$/MWh	(=Emissions Rate x CO_2 Price/lb)	$4	$6
Fuel Cost	$/MWh	(=Heat Rate x Gas Price)	$35	$55

9 Cap-and-trade programs and other market-based approaches to reducing emissions are treated in much greater detail in Chapter 24. They are mentioned briefly here simply to underscore that such programs have an impact on variable operating costs and thus on dispatch order. Understanding merit order helps one understand how market-based programs actually result in emissions reductions.

10 The example is based on: Sterkel, M. (2006, March). *Climate Action at the CPUC.* Presentation to the Public Service Commission of Wisconsin. Available at: https://psc.wi.gov/initiatives/cleanCoal/documents/3-10-06Meeting/CAClimate.pdf.

cost adder when evaluating the potential procurement of resources to reflect the risk for *future* greenhouse gas (GHG) legislation or standards. In other words, this cost adder reflects externalities beyond current regulatory compliance costs. The carbon price adder was initially set at $8 per ton of CO_2 emissions, with an escalation of approximately five percent each year. An example of how this price adder works, and its effect on the cost of generation and dispatch, is shown in the text box.[11]

California has also adopted a companion policy to its state cap-and-trade program that imposes a tariff on electricity imports from other states. This is intended to put out-of-state generators on an even footing with in-state generators subject to the state cap. Most of the electricity imported into California is generated by fossil-fueled EGUs. A rate of $17.92 per MWh is applied to unspecified out-of-state imports to account for their CO_2 emissions. However, power imported from the Pacific Northwest is discounted by 80 percent, to $3.58 per MWh, to reflect the low GHG emissions characteristics of power coming from the Northwest, most of which is generated by hydroelectric EGUs.[12]

At the local level, from 2000 to 2001 California's South Coast Air Quality Management District implemented a temporary policy to dispatch generators based on their nitrogen oxide (NO_X) emissions. This occurred during a time period when market manipulation by certain IPPs and failure by some generators to install emissions controls in time to comply with air quality regulations raised electric reliability concerns. The South Coast Air Quality Management District settled enforcement cases with some power producers that required their EGUs to operate on environmental dispatch principles based on minimizing NOx emissions, until the required emissions controls were installed and operating.

As part of the Ozone Transport Commission efforts to characterize emissions associated with "high electric demand days," the New York ISO and the utility Consolidated Edison analyzed the effects of a potential regional policy that would use a multivariate analysis to minimize regional NO_X emissions through dispatch decisions. This framework was based on:

- A robust air quality forecast, which is already in place in the Ozone Transport Commission region;
- A near-term load forecast from the regional electricity grid operator, currently standard practice in several regions; and
- An emissions forecast based on predicted dispatch from the load forecast.[13]

In this example, the New York research effort optimized dispatch on NO_X emissions, which can vary from less than 0.10 pounds per MWh (lbs/MWh) for a new NGCC EGU to more than 25 lbs/MWh for a diesel engine. Although NO_X was optimized in the New York research, CO_2 could similarly be optimized. CO_2 emissions fall in a tighter range, from approximately 750 lbs/MWh for an NGCC EGU to more than 2100 lbs/MWh for the average US coal-fired EGU.[14]

In fact, today's computing powers would permit optimization across multipollutants so that dispatch would reduce CO_2 emissions and, at the same time, not result in increased criteria pollutant emissions.[15] Although such analyses would indeed be complicated, transmission system operators routinely deal with complex, diverse, and rapidly changing conditions (e.g., management of the generation from wind turbines as it varies over the course of each day).

Outside the United States, China took a significant step in 2007 to adopt a groundbreaking environmental dispatch rule, and today the policy is being piloted in several Chinese

11 Supra footnote 10.

12 Western Electricity Coordinating Council. (2011, December). *Scoping Document for California AB32 Sensitivity for 2011 TEPPC Study Program.*

13 Zhang, K. M., Schuler, R., Nguyen, M., Chen, C., Palacio, S., & Valentine, K. (2012). *Dynamic Energy and Environmental Dispatch: Achieving Co-Benefits of Power Systems Reliability and Air Quality.* Cornell University, US Department of Energy, and Consortium for Electric Reliability Technology Solutions. Available at: http://energy.gov/sites/prod/files/1-7%20Dynamic%20Energy%20and%20Environment%20Dispatch%20PRESENTATION.pdf.

14 The Regulatory Assistance Project. (2001, November). *Model Regulations for the Output of Specified Air Emissions from Smaller-Scale Electric Generation Resources: Model Rule and Technical Support Documents.* Available at: http://www.raponline.org/document/download/id/421. Refer to emissions data from Figures 2 (NO_X) and 4 (CO_2), on pages 33 and 34.

15 Aribia, H., Derbel, N., & Abdallah, H. (2013). *The Active-Reactive: Complete Dispatch of an Electrical Network.* Electrical Power and Energy Systems, Volume 44, pp. 236–248. Available at: http://www.researchgate.net/publication/256970301_The_activereactive__Complete_dispatch_of_an_electrical_network

provinces.[16] The rule, developed jointly by energy and environmental regulatory authorities, establishes a mandatory dispatch order based on a combination of thermal efficiency and pollutant emissions. Whereas the standard international practice of security-constrained economic dispatch seeks to minimize total variable costs on the system – which in practice are mostly fossil fuel costs – this approach aims to include consideration of emissions. Specifically, where environmental dispatch is applied, generating units are scheduled according to the following priority ranking:

- Non-dispatchable renewable energy generating units (e.g., wind);
- Dispatchable renewable energy generating units (e.g., biomass);
- Nuclear power plants;
- Combined heat and power facilities that meet specified thermal efficiency criteria;
- Natural gas, coal-bed gas, and gasification generating units;
- Coal-fired power plants – within this category facilities are ranked by thermal efficiency, and plants with the same thermal efficiencies are ranked according to sulfur dioxide emissions rates; and finally
- Oil-fired generating facilities.[17]

In order for Chinese regulators to collect the necessary data to implement this dispatch approach, the regulations require installation of real-time emissions and heat-rate monitors at all thermal units and data sharing across agencies to establish and maintain an index of generating units for each provincial or regional grid.

4. GHG Emissions Reductions

Very little empirical work has been done on the potential GHG reductions from changing the dispatch order of power plants in the United States, partly because there is little direct experience with environmental dispatch in the United States. Potential reductions from this practice would depend on what variables are accounted for in determining generator costs, at what cost level they are incorporated (e.g., are public health impacts or other externalities factored in and, if so, at what cost?), and what resources are available to meet load. The sum of fuel, capital, and internalized costs of current externalities for each generating unit would determine dispatch order, from which GHG reductions would follow.

A 2010 report by the Congressional Research Service (CRS) looked at the potential emissions reductions that

Table 21-2

Estimate of Maximum Displaceable CO_2 Emissions From a US Re-Dispatch Strategy, Based on 2007 Data[19]

(1)	(2)	(3)	(4)	(5)	(6)
Estimated Hypothetical Coal Generation Displaced by Natural Gas (MWh)	Estimated CO_2 Emissions From Displaced Coal Generation (Million Metric Tons)	Estimated CO_2 Emissions From NGCC Generation Used to Displace Coal (Million Metric Tons)	Net Reduction in Emissions of CO_2 by Natural Gas Displacement of Coal (Million Metric Tons) (2) - (3)	Total CO_2 Emissions From Coal for Power Generation, 2007 (Million Metric Tons)	Hypothetical Net Reduction in CO_2 Emissions as a Percentage of 2007 Total Electric Power Coal Emissions of CO_2 (4) / (5)
640,128,780	**635.7**	**253.6**	**382.1**	**2,002.4**	**19%**

16 See: The Regulatory Assistance Project. (2013, October). *Recommendations for Power Sector in China: Practical Solutions for Energy Climate and Air Quality and Integrating Energy and Environmental Policy.* Available at: http://www.raponline.org/document/download/id/6869

17 China National Development and Reform Commission, State Environmental Protection Agency, State Electricity Regulatory Commission, and the National Energy Bureau, 2007. Available at: http://en.ndrc.gov.cn/

18 Kaplan, S. (2010, January). *Displacing Coal With Generation From Existing Natural Gas-Fired Power Plants.* Congressional Research Service. Available at: http://assets.opencrs.com/rpts/R41027_20100119.pdf.

19 Supra footnote 18 at page 9.

could be achieved from changing the dispatch of existing EGUs to maximize the output of NGCC EGUs.[18] The CRS evaluated a hypothetical scenario in which all existing NGCC EGUs were assumed to operate at 85-percent capacity factors (i.e., operate at 85 percent of their rated capacity on an annual average basis). The increases in NGCC dispatch were offset by decreases in the dispatch of coal-fired steam EGUs. The CRS analyzed this scenario to provide an estimate of the theoretical maximum reduction in emissions from re-dispatch strategies, but acknowledged that "it is unlikely that this maximum could actually be achieved" for a number of technical reasons. The results of this maximum potential scenario, showing a 19-percent reduction in CO_2 emissions from coal-fired power plants, are summarized in Table 21-2.

In the same report, the CRS also looked at two re-dispatch scenarios that used the proximity of NGCC EGUs to coal-fired EGUs as a proxy for assessing one of the most significant constraints on maximum potential: transmission system limitations. In these scenarios, the CRS used the same assumptions as in the maximum potential scenario, but with the added assumption that re-dispatching from coal to gas EGUs is only feasible when the EGUs are within 10 miles (one scenario) or 25 miles (the other scenario) of each other. The results, showing a more modest three- to five-percent reduction in CO_2 emissions, are summarized in Table 21-3.

In the proposed Clean Power Plan, the EPA established goals for each state based on an assumption that NGCC EGUs could feasibly operate at a 70-percent capacity factor. The EPA summarized the potential emissions reduction and costs of this strategy in an associated technical support document. The EPA's modeling results indicated that a potential 11-percent reduction in emissions was possible through this strategy, compared to a base case without re-dispatching. If NGCC EGUs were assumed to operate at an even higher 75-percent capacity factor, a 14-percent reduction in CO_2 emissions was found to be possible.[21]

The Brattle Group conducted "proof of concept" modeling in support of the environmental dispatch concept it developed with Great River Energy.[22] As a reminder, the cooperative proposed that MISO could impose a CO_2 emissions price on EGUs under its control, which would then affect dispatch order. The price would be set at whatever

Table 21-3

Estimate of Displaceable CO_2 Emissions From a US Re-Dispatch Strategy Constrained for Proximity, Based on 2007 Data[20]

Case (1)	Category (2)	Amount Displaced (3)	Amount Displaced as a % of the Maximum Potential Displacement of Coal by Existing NGCC Plants (4)	Amount Displaced as a % of Total Electric Power Sector Coal MWh and Associated CO_2 Emissions (5)
Generation and CO_2 Displaced for Coal Plants Within 10 Miles of a NGCC Plant	Generation	101.8 Million MWh	16%	5%
	CO_2 Emissions	58.1 Million Metric Tons	15%	3%
Generation and CO_2 Displaced for Coal Plants Within 25 Miles of a NGCC Plant	Generation	181.5 Million MWh	28%	9%
	CO_2 Emissions	104.8 Million Metric Tons	27%	5%

20 Supra footnote 18.

21 US EPA. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions From Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602 at page 3-26. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures.

22 Supra footnote 7.

level would be necessary to change dispatch order enough to ensure compliance with Clean Power Plan regulations across the system. The Brattle Group developed three different illustrative pricing scenarios, all of which would achieve (according to the modeling results) at least a 30-percent reduction in MISO-wide GHG emissions by 2035.

There has been some analysis of the impacts of environmental dispatch in China. Initially the environmental dispatch method was implemented in five provinces. The experience across those five initial provinces generally showed that more efficient coal units displaced dirtier units, resulting in significant reductions in coal combustion and CO_2 emissions. The average rate of coal consumption in Guangdong province, for instance, declined 3.4 percent from 323 grams per kWh to 312 grams per kWh in the first two years of implementation from 2007 to 2009.[23] Simulation studies for a selection of provinces have produced similar estimates of potential coal savings, suggesting that CO_2 emissions could be reduced by about three percent if the policy was broadly adopted across the nation.[24] The dispatch rule also may have the effect of driving future investment toward cleaner and more efficient units, as is already being seen in the pilot provinces – although this is clouded by a contention over how negatively affected plants will be "compensated" for decreased operating hours.

As noted previously, dispatch order can also change as an indirect result of imposing a price on emissions through a cap-and-trade policy or carbon tax. The emissions reductions that are achievable through either of those policies are explored in more detail in Chapters 24 and 25.

5. Co-Benefits

Any policy that changes the dispatch order of power plants for the purpose of reducing CO_2 emissions is likely to simultaneously reduce the emissions of other air pollutants. Other environmental impacts associated with some of the higher emitting sources of generation, such as

Table 21-4

Types of Co-Benefits Potentially Associated With Changing the Dispatch Order of Power Plants

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	No
Economic Development	No
Other Economic Considerations	No
Societal Risk and Energy Security	No
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	No
Displacement of Renewable Resource Obligation	Maybe
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	No
Other	No

23 Gao, C. & Li, Y. (2010). *Evolution of China's Power Dispatch Principle and the New Energy Saving Power Dispatch Policy.* Energy Policy, 38, 7346–7357. Available at: http://www.sciencedirect.com/science/article/pii/S0301421510006257

24 Mercados Energy Markets International. (2010, August). *Improving the Efficiency of Power Generation Dispatch in China.* The World Bank. Policy Note.

the need for cooling water and the production of coal ash, may also be reduced.

For environmental dispatch policies, the magnitude of these complementary co-benefits would depend upon the specific variables on which the environmental dispatch were based, and how those variables were valued in determining dispatch order. To the extent that low or zero emissions supply options are available (e.g., wind or solar photovoltaic generation), multipollutant emissions reductions could be substantial. For example, modeling work completed for proposed implementation of the 1990 US Clean Air Act Amendments reflected that, for the state of Ohio, NO_X reductions of up to 50 percent were possible from a combination of environmental dispatch and energy conservation programs.[25]

The full range of co-benefits that can be realized through changing dispatch order is summarized in Table 21-4.

6. Costs and Cost-Effectiveness

Changing the dispatch order of power plants will by its very nature increase the overall short-term cost of electric power, because EGUs will be dispatched in new ways that are not based solely on their short-term variable costs. The costs and cost-effectiveness of these policies will vary greatly depending on the specific location, situation, the EGUs available and their costs, and the policy design itself. As such, it is not possible to draw general conclusions about costs and cost-effectiveness; however, specific examples are examined here.

As noted earlier, one way to change dispatch order is to impose a cost on emissions indirectly (through a cap-and-trade system) or directly (through a tax). The cost of a cap-and-trade policy is ultimately reflected in the market price of emissions allowances. This is true because generators will include the market value of allowances in their calculation of variable operating costs even if allowances are allocated at no cost, because any allowance that isn't used can be sold. Of course, the price of allowances will in large part depend on the stringency of the cap relative to expected levels of emissions. If generators expect that the industry as a whole will have little problem complying with the cap, allowances will have little value; if they see the cap as being very challenging, allowances will have a greater value. The Northeastern and Mid-Atlantic states participating in the Regional Greenhouse Gas Initiative (RGGI) use auctions to distribute allowances. Since the first auction in 2008, allowance prices have ranged from $1.86 to $5.02, with a noticeable increase in prices since the cap was made more stringent in 2013.[26] In California, allowance prices for the AB32 trading program have ranged between about $10 and $12 since the first auction in November 2012.

Of course, in the case of a carbon tax, the cost of changing dispatch will be predetermined by the amount of the tax, as that amount will be directly added to variable operating costs when dispatch decisions are made. With a carbon tax, what is uncertain is the extent to which emissions will decrease.

Although cap-and-trade systems and carbon taxes add to the short-term price of wholesale electricity, they also create a revenue stream that can be used to offset such price increases. The RGGI states, for example, use allowance auction revenues to fund consumer energy efficiency programs that reduce electric demand. Evidence to date suggests that this reduction in demand more than offsets the added cost of CO_2 allowances, as wholesale energy prices in the region have declined since the start of the program. In this manner, the RGGI states get the emissions benefits of imposing an emissions cost that changes dispatch order, without increasing total system costs. More details on the costs and cost-effectiveness of cap-and-trade programs can be found in Chapter 24. Details on carbon taxes are found in Chapter 25.

In a technical support document that was published with the proposed Clean Power Plan, the EPA describes its use of computer modeling to assess the potential costs of the building block that focuses on changing dispatch order: "EPA employed the Integrated Planning Model (IPM), a multi-regional, dynamic, deterministic linear programming model of the US electric power sector that the EPA has used for over two decades to evaluate the economic and emissions impacts of prospective environmental policies. IPM provides a wide array of projections related to the electric power sector and its related markets (including least cost capacity expansion and electricity dispatch

25 Heslin, J., & Hobbs, B. (1990). *Application of a Multi-Objective Electric Power Production Costing Model to the US Acid Rain Problem.* Case Western Reserve University. Engineering Costs and Production Economics, 20, 241–251. Available at: http://econpapers.repec.org/article/eeeecpeco/v_3a20_3ay_3a1990_3ai_3a2_3ap_3a241-251.htm

26 Auction results are summarized at: http://www.rggi.org/market/co2_auctions/results.

projections) while meeting fuel supply, transmission, dispatch, and reliability constraints… In executing this analysis, the EPA conducted a number of scenarios to quantify the relationship between the amount and cost of re-dispatch."[27] The results from three of these scenarios, in which the dispatch of NGCC EGUs was assumed to reach national average capacity factors of 65 percent, 70 percent, and 75 percent, are summarized in Table 21-5.

Table 21-5

Modeled Impacts of Re-Dispatch Scenarios[28]

NGCC EGU Average National Capacity Factor (%)	Average CO_2 Emissions, 2020–2029 (Million Metric Tons)	Emissions Reduction From Base Case, 2020–2029 (%)	Average Cost of Emissions Reductions, 2020–2029 ($ per metric ton)
Base Case	2215	N/A	N/A
65	2022	9	$21
70	1969	11	$30
75	1915	14	$40

In the "proof of concept" modeling that it conducted in support of the environmental dispatch concept it developed with Great River Energy, the Brattle Group developed three different illustrative pricing scenarios.[29] In one scenario, the CO_2 emissions price started at $5 per ton in 2013 and grew by five percent each year. In the second scenario, the price started at $10 per ton and grew at six percent per year. And in the third scenario, the price didn't start until 2030, but began at $30 per ton and grew at ten percent per year. Each of these pricing pathways was found to be sufficient to alter dispatch enough to reduce MISO-wide GHG emissions in the year 2035 by at least 30 percent.

The cost-effectiveness of environmental dispatch policies will always depend on which of the external environmental, climate, public health, and social costs policymakers include in the total cost that will determine the new dispatch order of EGUs. Discussing costs and cost-effectiveness of environmental dispatch has a different flavor than such discussion applied to traditional end-of-pipe emissions controls, where the dollars per ton of pollutant(s) reduced can be readily determined. With environmental dispatch, proponents argue that EGUs impose external environmental, climate, public health, and social costs that today are borne by society as a whole. This policy recommends that these societal costs, to the extent that they can be quantified, be included in the operating costs of EGUs. Doing so will change the relative order of what units are dispatched. Units with higher heat rates and greater external effects will have the costs of those effects reflected in their operating costs, and such units will operate fewer hours than units that have lower costs.

To incorporate these external costs, policymakers must identify which of the external variables should be associated with electricity generation, quantify their costs, and reflect some or all of the costs into the operating costs of EGUs. Several states and regions now either require that costs for these externalities be calculated, or include them in cost-effectiveness calculations to the extent that such values can be determined.[30] Recent work by the National Academy of Sciences and by Synapse Energy Economics enables metrics to be developed on the public health impacts per kWh of electricity generated, as well as the

27 Supra footnote 21.

28 Adapted from Table 3-7 at: Supra footnote 21.

29 Supra footnote 7.

30 See, for example: Delaware and Delmarva integrated resource planning (IRP) requirements. Delaware Department of Natural Resources and Environmental Control, comments on Delmarva's IRP, September 16, 2013. Available at: http://depsc.delaware.gov/electric/12-544%20DNREC%20Comments.pdf. Another example comes from the Northwest Power Act, which requires the Northwest Power and Conservation Council to account for environmental externalities in their resource costs and benefits calculations, to the extent to which these things can be monetized. Refer to the Regional Technical Forum's Recommendations to the Bonneville Power Administration Regarding Conservation and Renewable Resources Eligible for Conservation and Renewable Resources Rate Discount and Related Matters, RTF Meeting August 2000. Available at: http://rtf.nwcouncil.org/meetings/2000/08/rtfcrdrecmd.doc.

costs of various generating technologies (including wind, solar, and biomass). For example, the National Academy of Sciences report reflects a median impact of coal-fired electricity generation of 4.36 cents per kWh, with a 95th-percentile cost of over 12 cents per kWh (which is higher than the retail cost of electricity in many states).[31] The Synapse report includes all supply-side resources (coal, oil, gas, solar, wind, biomass, nuclear); their costs; subsidies provided; and climate change, air, land, and water impacts.[32]

Determining the external costs associated with various EGUs should not be a major obstacle in light of the wealth of existing research and data. For example, transmission operators in New England routinely calculate the system's marginal emissions rate to help air regulators assess the benefits of energy efficiency and renewable energy programs. The Northwest Power and Conservation Council's definition of cost-effectiveness allows the inclusion of external costs and benefits from energy efficiency programs. The EPA's Environmental Benefits Mapping and Analysis Program enables air regulators to calculate the public health benefits of emissions control measures they are evaluating.[33] The Regulatory Assistance Project identified more than two dozen categories of costs associated with power generation, including several categories of externalities that could potentially factor into dispatch decisions.[34]

7. Other Considerations

Seeking to maximize GHG reductions, including externalities (uncaptured societal costs imposed by EGUs) in dispatch decisions, is consistent with how good integrated resource plans are being prepared today, how cost-effectiveness screens for energy efficiency programs are determined, and how transmission planning is conducted. The complementary nature of environmental dispatch policies with related energy policies makes for a comprehensive package on which to engage energy regulators and electricity grid operators.

Although the cost impacts of changing dispatch order have already been acknowledged in this chapter, a few other considerations regarding the potential of this strategy bear mentioning. Most of the recent analyses of re-dispatch opportunities in the United States have focused on the potential to increase generation from lower emitting NGCC EGUs and reduce generation from higher emitting EGUs, especially coal-fired EGUs. One limitation on the potential of this strategy that is generally noted is that the supply of natural gas, the capacity to transport the gas to NGCC EGUs, and the capacity to store natural gas at or near NGCC EGUs may not allow for across-the-board, sustained, high capacity factor use of NGCC EGUs. Regional and seasonal limitations on the natural gas supply chain could come into play as capacity factors increase. In addition, if the amount of natural gas used for electric generation increases dramatically, there would likely be impacts on the commodity price of natural gas that would affect other uses of the fuel, notably for industrial processes and space heating.[35]

Large-scale changes in dispatch order could also have consequences for the viability of some EGUs. Fossil-fueled EGUs subject to new environmental requirements may choose retirement over pollution control retrofits if they expect to run at a lower capacity factor in the future. Even in the absence of new environmental requirements, some owners of fossil-fueled EGUs that move lower in the dispatch order may find that they are now losing money and choose to cut their losses by retiring the unit. This could conceivably raise new problems with resource adequacy (i.e., the ability to satisfy peak demand for electricity). However, safeguards are in place. Balancing authorities (e.g., an ISO or RTO such as PJM Interconnection) and regional reliability organizations are

31 National Academy of Sciences. (2010). *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use.* ISBN 978-0-14640-1.

32 Keith, G., Jackson, S., Napoleon, A., Comings, T., & Ramey, J. A. (2012, September). *The Hidden Costs of Electricity: Comparing the Hidden Costs of Power Generation Fuels. Prepared by Synapse Energy Economics for the Civil Society Institute.* Available at: http://www.civilsocietyinstitute.org/media/pdfs/091912%20Hidden%20Costs%20of%20Electricity%20report%20FINAL2.pdf.

33 Refer to the EPA website at: http://www.epa.gov/air/benmap/.

34 Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits).* Montpelier, VT: The Regulatory Assistance Project. Available at www.raponline.org/document/download/id/6739.

35 For more information on these limitations, refer to: Supra footnote 18.

ultimately responsible for ensuring that grid reliability will not suffer as a result of an unexpected or abruptly planned unit retirement. Requests to deactivate an EGU are reviewed by the balancing authority, who identifies any potential impacts on grid reliability. If problems are identified, deactivation of the EGU will not be allowed until steps are taken to alleviate the problem, such as changes in transmission, addition of new generating capacity, and the like.[36] Reliability must-run units are subject to special wholesale energy market rules that allow them to operate out of merit order until required actions are taken to ensure grid reliability. Those rules also dictate who pays for the costs of uneconomic dispatch.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on changing the dispatch order of power plants.

- Bernow, S., Biewald, B., & Marron, D. (1991, March). *Full Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation.* The Electricity Journal, 20–33. Available at: http://econpapers.repec.org/article/eeejelect/v_3a4_3ay_3a1991_3ai_3a2_3ap_3a20-33.htm
- Federal Energy Regulatory Commission Staff. (2005, November). *Economic Dispatch: Concepts, Practices, and Issues.* Available at: http://www.ferc.gov/eventcalendar/Files/20051110172953-FERC%20Staff%20Presentation.pdf.
- Kaplan, S. (2010, January). *Displacing Coal With Generation From Existing Natural Gas-Fired Power Plants.* Congressional Research Service. Available at: http://assets.opencrs.com/rpts/R41027_20100119.pdf.
- Li, X. (2009). *Study of Multi-Objective Optimization and Multi-Attribute Decision-Making for Economic and Environmental Power Dispatch.* Electric Power Systems Research, 79, 789–795.
- Palinachamy, C., & Sundar Babu, N. (2008). *Analytical Solution for Combined Economic and Emissions Dispatch.* Electric Power Systems Research, 78, 1129–1137. http://www.sciencedirect.com/science/article/pii/S0378779607001939
- Yalcinoz, T., & Koksoy, O. (2007). *A Multiobjective Optimization Method to Environmental Economic Dispatch*. Electrical Power and Energy Systems, 29, 42–50. http://www.sciencedirect.com/science/article/pii/S0142061506001086

9. Summary

A strategy in which environmental and public health variables are priced and included as part of a generator's operating costs – thereby affecting their dispatch order – could help a state to reduce GHG and criteria pollutant emissions, and contribute to the state's air quality plan as a valid control measure.

To the extent that costs in addition to the operating costs of an EGU can be determined, they can be included as part of the variable operating costs associated with that particular unit. This can be done across the entire fleet of generating units that are dispatched by a grid operator. In practice, economic dispatch would still be used, but now each unit's costs would be more reflective of the environmental and public health effects associated with its generation of electricity. The unit's operation would, in turn, hinge on its new, imputed or "full-cost" place in the dispatch order.

Environmental dispatch is just one policy in a suite of electric grid operation and transmission policies that could help states reduce their GHG emissions. Together with the complementary policies (described in other chapters) of revised transmission pricing, revised capacity market practices, revised ancillary services, and revised transmission siting and pricing, environmental dispatch would form a package that adds value to the role of energy regulators and electricity grid operators, while also maintaining and improving electric reliability.

36 Units that are not allowed to retire for reliability-related reasons are given a special designation and are subject to special wholesale energy market rules. A generic term for this designation is "reliability must-run," but other terms are used regionally. For example, MISO uses the designation "system support resource."