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An Energy Imbalance Market in the Southeastern United States

Context, Benefits, and Design Considerations for Stakeholders and Policymakers

By: Matt Butner, Ph.D.

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Executive Summary

Over the past twenty years, organized wholesale electricity markets have demonstrated unambiguous success in coordinating electricity production across utilities over large geographic areas in the United States. Despite the clear benefits of organized markets, however, the Southeast remains a bastion of the traditional organization of electricity production characterized by long-term contracts, bilateral trades, and a lack of competition. This organizational structure can result in inefficient and inflexible operations that are costly to customers and unyielding to the ongoing energy transition towards variable renewable energy resources.

This report establishes the case for an **Energy Imbalance Market** (**EIM**)—a voluntary wholesale electricity market operating in real-time—in the Southeastern United States. While a more comprehensive and widely implemented Regional Transmission Organization (RTO) may ultimately be optimal for the Southeast, an EIM is a straightforward, low-cost first step toward a more efficient and flexible electricity grid that can be achieved without structural reform.

Perhaps most importantly, a traditional EIM is likely to identify more cost-saving opportunities and better balance renewable generation than existing proposals for energy market reform in the Southeast—namely, the proposed **Southeast Energy Exchange Market** (**SEEM**). Specifically, the modeling conducted in this report estimates that an EIM could save $100–600 million annually to Duke Energy alone, which encompasses approximately 40 gigawatts of generating capacity. In contrast, SEEM is projected to save around $40–50 million annually across its full territory, encompassing four times the generating capacity of Duke Energy.

In summary, this report establishes the following:

- **Every region of the United States except the Southeast has some real-time energy market that dispatches electricity using a Security Constrained Economic Dispatch algorithm**. These markets, including EIMs and those carried out by RTOs, generate significant benefits by identifying the least-cost reliable way of generating electricity to balance supply and demand.

- **An EIM offers three primary benefits over the Southeast's status quo:**
    - *Economic benefits* of production cost savings realized by mutually beneficial trades of electricity in real-time amongst participating utilities.
    - *Environmental benefits* of better integration and reduced curtailment of low-cost, zero-carbon renewable energy generation.
    - *Reliability benefits* of enhanced situational awareness, automated response to energy shortfalls, and reserve shaving that reduces the costs of balancing supply and demand.

- **The economic benefits of an EIM in the Southeast can be large.** This report uses an open-source dispatch model to quantify the potential economic benefits of an EIM to Duke Energy Carolinas and Duke Energy Progress (hereafter Duke Energy). Modeling results show Duke Energy could have avoided $100 million to $600 million in production costs in 2018 if it fully participated in an EIM. A large portion of the production cost savings is realized in a small number of hours, when the cost to produce electricity in Duke's footprint is greatest.

- **The recently proposed SEEM has the potential to provide some, but not all, of the benefits of a well-designed EIM.**
  - SEEM's fundamental market design—an "exchange-based" market that automates bilateral transactions—is unlikely to realize the production cost savings of an EIM.
  - SEEM should embrace the best available practices in electricity market design, including transparent price signals, location-based pricing, 5-minute dispatch, stakeholder representation, and independent market monitoring. It remains unclear whether SEEM includes some, or any, of these practices.

- **A Southeastern EIM operated by PJM is likely the best EIM option for North Carolina.**
  - The simulations in this report show Duke Energy would have realized the largest cost savings if it had been a part of an EIM including all Carolina utilities and PJM.

- **State regulators and legislators have an important role to play in encouraging the formation of, and participation in, a well-designed EIM.**
  - Both Carolina legislatures should pass bills that explore the benefits and costs of electricity market reform. In this analysis, both an RTO and an EIM should be considered.
  - Policymakers can encourage Carolina utilities to establish a Memorandum of Understanding (MOU) with PJM to explore the costs and benefits of a Southeastern EIM, much like the PacifiCorp-CAISO MOU that established the Western EIM.

- **Recent proposed legislation in the Carolinas and discussions of SEEM indicate that the Southeast is ready for electricity market reform.** When moving forward with this process, it is important that all of the region's relevant stakeholders have the opportunity to evaluate the options available. As shown in this report, economic theory on electricity market design and demonstrated success of existing electricity markets can help inform the process.

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Tables and Figures

I. Introduction

"Trade makes everyone better off" and "markets are usually a good way to organize economic activity" are not just textbook concepts.[1] Applying these principles to the electric power sector in the Southeastern United States can better integrate renewable generation, improve reliability, and save ratepayers hundreds of millions of dollars per year.

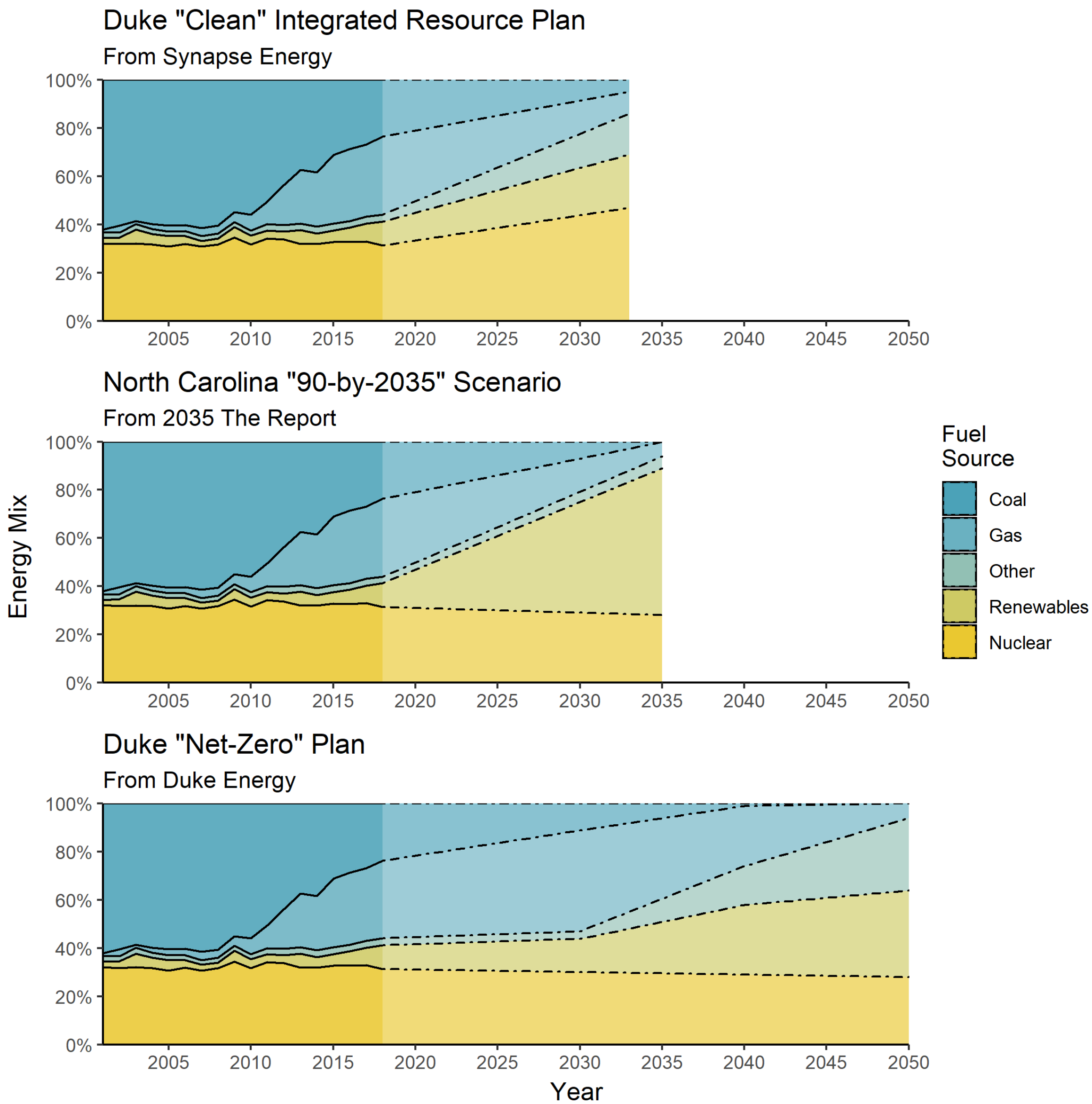
Over the past twenty years, Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) have collectively generated billions of dollars in annual economic benefits while overseeing a majority of the electricity produced in the United States.[2] Fundamentally, these organizations operate markets that facilitate beneficial trades of electricity—especially during periods of high demand or shortfalls of supply—using well-established technologies and algorithms. Despite the evidence showing the benefits of organized wholesale electricity markets operated by RTOs, the Southeastern United States has been laggard in embracing basic economic principles.

This report makes the case for an Energy Imbalance Market (EIM) in the Southeastern United Sates as a way to increase trade between utilities, better integrate renewable generation, and enhance reliability. An EIM is not as comprehensive as the more widely implemented RTO, and is unlikely to generate benefits of similar magnitude.[3] However, an EIM can be straightforward to implement, preserves the authority of state policymakers, and maintains resource adequacy. Perhaps most importantly, a well-designed EIM can realize more cost-saving opportunities and better balance renewable generation than the recently proposed Southeast Energy Exchange Market (SEEM).

Enhanced coordination of electricity production is now more important than ever, as declining costs of solar, wind, and battery resources—and a pressing need to mitigate the harms of climate change—are prompting a technology-driven transition in the electric power sector. With more renewable generation, electricity generators must respond to more weather-based fluctuations in the imbalance between supply and demand. A wholesale electricity market over a wide geographic area can reduce the overall variability of this imbalance, and more efficiently respond to sudden fluctuations in electricity production in real-time. These features of a wholesale market reduce curtailment and the cost of integrating renewable generation. With anticipated growth of renewable generation in North Carolina's future, as show in **Figure 1**, reforms to the organization of electric power should be pursued to maximize the benefits renewables provide and reduce the cost of the transition.

This report proceeds as follows. To lend context, section II provides an abridged background on the organization of the electric power sector while highlighting some of the most common arrangements over the past century. Section III provides a comprehensive discussion of an EIM in the Southeast, including its basic operations, how it compares to existing institutions, its potential benefits, and how it compares to alternative reforms. Of particular note, this section reports the results from a simulation exercise that quantifies the benefits of increased trade that would have accrued to Duke Energy in 2018. Section IV enumerates considerations for the design of an EIM or similar energy market in the Southeast, including market scope and market design. Section V concludes.

Figure 1 – Future Fuel Mix in North Carolina (or Duke Energy).



Four future scenarios, all showing an increased share of electricity generated by renewable generaiton. The top two plots are alternatives to Duke Energy's Integrated Resource Plan with the goal of reducing greenhouse gas emissions and minimizing production costs, respectively. The third plot shows the North Carolina specific fuel mix from a modeling exercise that achieves 90% carbon-free electricity by 2035 while reducing energy costs and generating jobs. The bottom plot shows Duke Energy's plan to achieve net-zero annual greenhouse gas emissions by 2050. See, in order from top to bottom, NCSEA initial comments on NC PUC DOCKET NO. E-100, SUB 157 Attachement 1 at 6 (2019); NRDC comments on NC PUC DOCKET NO. E-100, SUB 157 Attachment 1 at 6 (2019); Amol Phadke et al., 2035 The Report Technical Appendix, at 49 (2020); Duke Energy, 2020 Climate Report, at 26, (2020).

II. The Organization of the Electric Power Industry

A. Traditional Organization of Electricity Production

In the earliest days of electric power, companies providing electricity were invariably vertically integrated—owning and operating all generation, transmission, and distribution assets. This was because the act of electricity transmission and distribution was perceived to be inseparable from electricity production. As a result of vertical integration, and improvements in larger steam engine technology, electricity benefitted from economies of scale; a single large company could produce the same electricity at a lower cost than several smaller, competing companies.

Samuel Insull of Commonwealth Edison famously identified this "natural monopoly" problem of electric power, [4] which left unchecked will lead to the classic problems of a monopolist: prices, quantities, and quality of electricity divergent from what is economically efficient.[5] As a solution, Insull championed regulation.[6] Under regulation, vertically integrated utilities would be granted monopoly rights and a guaranteed profit so long as public regulators had oversight over the utility's investment decisions and pricing practices.

Electricity prices declined over the first half of the century, as economies of scale were realized, however the vertically integrated monopoly-utility structure is not without its imperfections.[7] In particular, insular electric power companies guaranteed a profit do not have the economic incentive to seek out the gains from trade espoused in economic principles, nor do they face the forces of competition that require them to be mindful of their cost.[8] As a result, under the traditional organization of electricity production, utilities operated as balkanized entities, each separately producing electricity to achieve the complex balance between supply and demand within their own "balancing areas." Outside of Power Pool arrangements (discussed below), utilities under the traditional organization of electricity production would trade electricity only through long-run bilateral contracts or joint ownership arrangements if at all.

B. A Movement Towards Markets

The vertically integrated monopoly utility paradigm was predominant throughout most of the twentieth century. In the late 1980s, however, it became subject to scrutiny for several reasons. First, economic research began to make clear the potential inefficiencies of insular vertically integrated utilities.[9] At the same time, other industries (like rail, trucking, and air-travel) were a promising success after undergoing regulatory reform. Finally, and perhaps most importantly, lower natural gas prices, large capacity investments, and technological improvements created a divergence between the average price of electricity (paid by retail customers) and the marginal price of electricity (determined by the wholesale price of electricity). As a result, retail electricity customers felt overcharged for electric power, and called for reform so that they could benefit more directly from low marginal cost electricity.[10]

During the late 1990s and early 2000s – nearly a century after Samuel Insull advocated for the traditional organization of electric power – reform rippled across the U.S. electric power sector as State and Federal regulators imposed changes to the organization of electric power.[11] Jointly characterized as "restructuring," these reforms included (*i*) the forced divestiture of electricity generation assets owned by vertically-integrated utilities, (*ii*) the creation of competitive retail markets for consumers to choose their service provider, and (*iii*) the encouragement towards—and formation of—open-access, organized markets for the wholesale trade of electricity.[12] Of these three reforms, the formation of open-access, organized markets for wholesale electricity has stood out as being the most successful in realizing economic efficiencies to date.[13]

The basic idea justifying an organized wholesale electricity market is straightforward. The natural-monopoly character of the electric sector is confined to transmission and distribution service, which continues to be most efficiently provided by a single market participant. For at least several decades, electric generation has not had the characteristics of a natural monopoly. On the contrary, competition in the generation sector can reliably deliver large cost savings to ratepayers relative to monopoly supply. Fortunately, the economic model for generation can be readily separated from that for transmission and distribution service.[14] So, for example, a transmission system operated by an impartial third party can serve as a platform where electricity generators owned by vertically integrated utilities or independent power producers can compete to sell electricity to utilities and electricity retailers across a large geographic footprint.

C. The RTO Paradigm

Organized electricity markets can take many different forms. In the US, they have been predominately implemented as part of RTOs in compliance with FERC Order 2000. An RTO is a non-profit organization that oversees the wholesale electricity grid in its footprint, and is best described by its FERC-codified minimum characteristics and functions, listed in **Table 1**. Of particular note, an RTO is characterized by independence from market participants, appropriate geographic scope, transmission operational authority, and exclusive authority over short-term reliability.

Table 1 – Characteristic and Functions of an RTO established by FERC Order 2000.

Minimum Characteristics of an RTO:	Minimum Functions of an RTO:
1. Independence from market participants 2. Appropriate scope and regional configuration 3. Possession of operational authority for all transmission facilities under RTO control 4. Exclusive authority to maintain short-term reliability of the grid	1. Tariff administration and design 2. Congestion management 3. Management of parallel path flow 4. Provision of ancillary services 5. Development of Open Access Same-time Information System (OASIS) 6. Market monitoring 7. Planning and expansion of facilities under its control

In general, the goal of an organized electricity market is to provide "reliable electricity at least cost to consumers."[15] RTOs carry out a number of activities to achieve this goal. The core of an RTO's short-run operations is the day-ahead and real-time energy market.[16] In both markets, the market operator collects information on every electricity generator's willingness to produce electricity (offers), every load serving entity's willingness to pay for electricity (bids), and several other factors including transmission congestion and the weather. The market operator uses all of this information to solve a complex but well-established algorithm to identify the least-cost way to reliably balance the supply and demand of electricity in real-time.

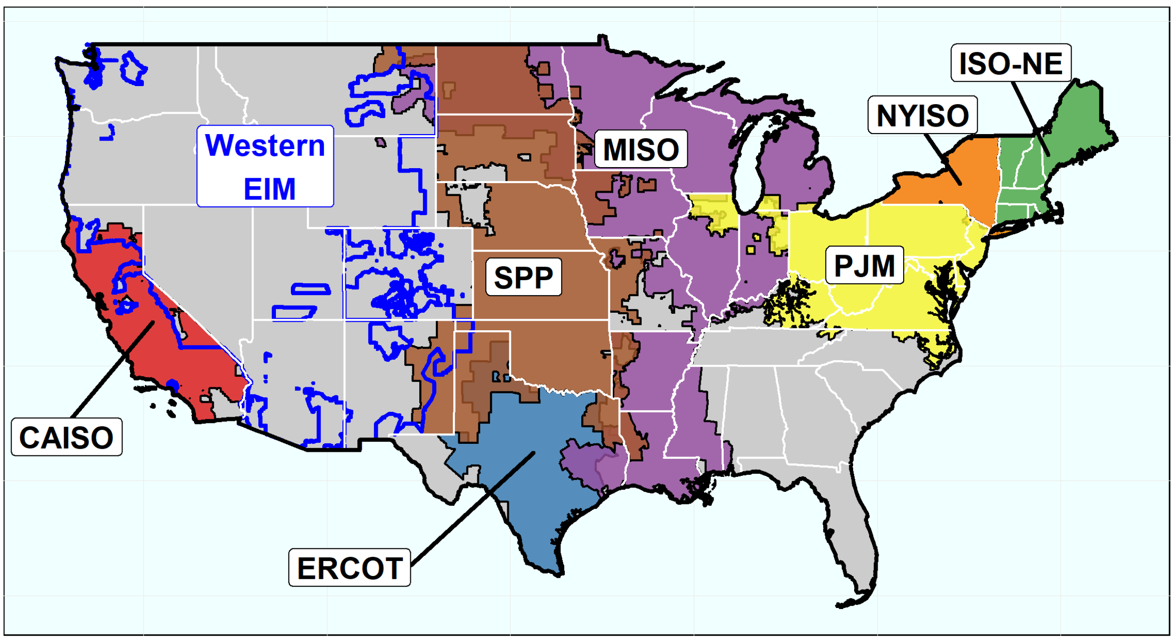
In the day-ahead market, the market operator jointly determines which electricity generators should operate (unit-commitment) and how much they should produce (dispatch) the following day. In the real-time market, the market operator resolves the dispatch problem based on the most up-to-date information including changes to electricity generators' offers and load serving entities' bids. Both markets determine dispatch by solving a Security Constrained Economic Dispatch (SCED) problem, typically every five minutes [17]

In general, SCED identifies the least-cost electricity generator by creating a "merit-order," which ranks all energy resources from low cost to high cost according to their offers.[18] The RTO dispatches the least-cost resources first, while also respecting transmission and electricity generator constraints. Every five minutes, the price for electricity is set by the last (marginal) energy resource producing electricity. Prices vary geographically by "node" according to the marginal cost of electricity, transmission congestion, and transmission losses. After the market clears, the settlement process compensates electricity generators the nodal price near them, and charges utilities the nodal price for the electricity they consume.

Other activities overseen by an RTO include ancillary services markets and congestion management in the short-run, and transmission and capacity planning in the long-run. The design of these features varies; however, they are all designed with the same goal of low-cost, reliable electricity.

Today, seven organized wholesale electricity markets have formed in the United States as RTOs, including the ISO New England (ISO-NE), New York ISO (NYISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), Electricity Reliability Council of Texas (ERCOT), PJM, and California Independent System Operator (CAISO). **Figure 2** maps the footprint of every organization that solves out the SCED problem, including the seven RTOs and the Western EIM.

Figure 2 – Map of Centralized Dispatch Energy Markets in the United States.



Map of Balancing Authority Areas of RTOs and Planned Members of the Western EIM. The extent of each Balancing Authority Area is defined by Homeland Infrastructure Foundation-level Data.

Figure 2 highlights the lack of an RTO (or EIM) in the Southeastern United States. Although several RTOs were independently proposed by utilities in the region to comply with FERC Order 2000, none of the proposals were ever implemented. [19] FERC commissioners first expressed concern over the lack of independence of the RTOs operations from major utilities in the area, and then later over limited geographic scope of the proposals.[20] Ultimately, drawn-out mediation amongst utilities, frustration by state regulators, and the coincident California electricity crisis led every proposal to a dead end.[21]

i. Demonstrated Benefits of an RTO

Over the past twenty years, RTOs have demonstrated immense benefits to their stakeholders, including electricity customers and utilities. The magnitude of the benefits provided by RTOs cannot be ignored. For example, PJM and MISO each quantified their annual benefit to exceed $3 billion.[22] While RTOs do have an administrative cost structure, the benefit they provide more than compensates.[23] This section outlines the benefits of an RTO for context, and in comparison to some of the alternative arrangements. In general, the benefits of an RTO include the following:

1. **Production Cost Savings:**
   Production cost savings from an RTO represent realized efficiencies along two channels: (1) *system efficiencies*, enhancing "the coordination and use of multiple plants," and (2) *plant-level efficiencies,* leading to "lower cost or higher availability at a particular plant."[24] A comprehensive retrospective analysis of the expansion of electricity markets across the United States estimates production cost savings average 5% of total production costs.[25] This number varies in application and is specific to the resources being integrated and the market design. Estimates generally range from 3 to 11%.[26] Overall, production cost savings represent roughly 10 to 20% of the self-identified benefits of RTOs.[27]

2. **Avoided Capacity Investments**:
   An organized electricity market, like an RTO, makes it easier for utilities to purchase wholesale electricity during periods of peak demand instead of using their own more expensive power plants built for that same purpose. This generates benefits to ratepayers through enhanced reliability and prevents redundant capital investments in generation capacity. This benefit increases with RTO size, as it pools electricity generators and combines diverse demand pattern. In addition, some RTOs organize competitive markets for generation capacity that can provide additional benefits if properly designed. This is the largest self-reported benefit of RTOs, accounting for 30 to 60% of total benefits.[28]

3. **Renewable Integration:**
   RTOs enhance the coordination of electricity generators, and so allow them to better respond to variable renewable generation and at a lower cost. In addition, the large geographic footprint of RTOs reduces variability of renewable generation in proportion to demand. Ultimately, an organized electricity market like an RTO reduces wasteful curtailment of renewable generation, and can minimize the cost of integrating variable renewable generation. In MISO, where there is a large amount of wind generation, the production cost savings from better integration of renewables provide RTO stakeholders with nearly half a billion dollars of benefits per year.[29]

4. **Grid Services:**
   Grid services maintain the stability and reliability of the transmission grid. RTOs ensure the adequate provision of grid services, including market-based mechanisms to provide ancillary services and congestion management. Although essential, especially as more renewable generation is added, grid services make up only a small share of an RTO's self-reported monetized benefits.[30]

5. **Reliability Through Transmission Planning and Management**:
   The transmission network is governed by economies of scale – it is much more efficient to build a single transmission network than many small ones providing the same level of service. This implies coordination of electricity transitions over a large geographic area, like an RTO, and can provide cost savings and identify potential efficiencies. Some RTOs serve as Transmission Planning Regions in compliance with FERC Order 1000.[31] Through a stakeholder process, RTOs plan transmission expansion in the context of their existing market for energy.[32] This transmission planning provides stakeholders with improved reliability and reduced congestion costs.[33]

D. Non-RTO Real-time Energy Arrangements

A wholesale electricity market, or market-like arrangement, need not be an RTO to provide some or all of the benefits outlined above. An RTO is simply the approach prescribed by FERC in Order 2000.[34] This section discusses other organized energy markets, or market-like arrangements, that promote mutually beneficial transactions between utilities in real-time. Although not as comprehensive as RTOs, these arrangements still provide some of the same benefits.

i. Power Pool

Soon after the traditional organization of electricity production was established, the benefits of coordinating the production of electricity among utilities became apparent. In 1927, three utilities formed what is now the PJM RTO as the first Power Pool after "realizing the benefits and efficiencies" of coordinating electricity production.[35]

A Power Pool is the most limited departure from the traditional organization of electricity markets. In this arrangement, multiple utilities come together to form an agreement on how to generate electricity and interchange power according to a pre-determined set of rules. In effect, this arrangement operates like a multilateral contract between all member utilities, similar to a cooperative. It can be thought of as a market insofar as the negotiations between member utilities that set the prices and terms by which trade occur are market-like.

A Power Pool is operated by an administrator whose goal is to ensure reliable, low-cost electricity is provided to cooperating utilities while also adhering to the Power Pool's rules. Some use centralized dispatch according to electricity generators' reported costs and availability (known as a "tight Power Pool," similar to a joint-dispatch agreement amongst all utilities). Others involve private bilateral transactions (on diverse contractual terms) between member utilities with varying terms (a "loose Power Pool").[36] The challenges accompanying a Power Pool include establishing membership and exit fees, rates for service, and participant-specific stipulations. Although a Power Pool can foster mutually beneficial trades between member utilities, there is no guarantee the operations are economically efficient.

Throughout the US, Power Pools have played a historically important role in the organization of electricity markets. Sometimes these arrangements have been steppingstones to the establishment of a more formal RTO, as in the case of PJM, SPP, ISO-NE, and NYISO, ERCOT.[37]

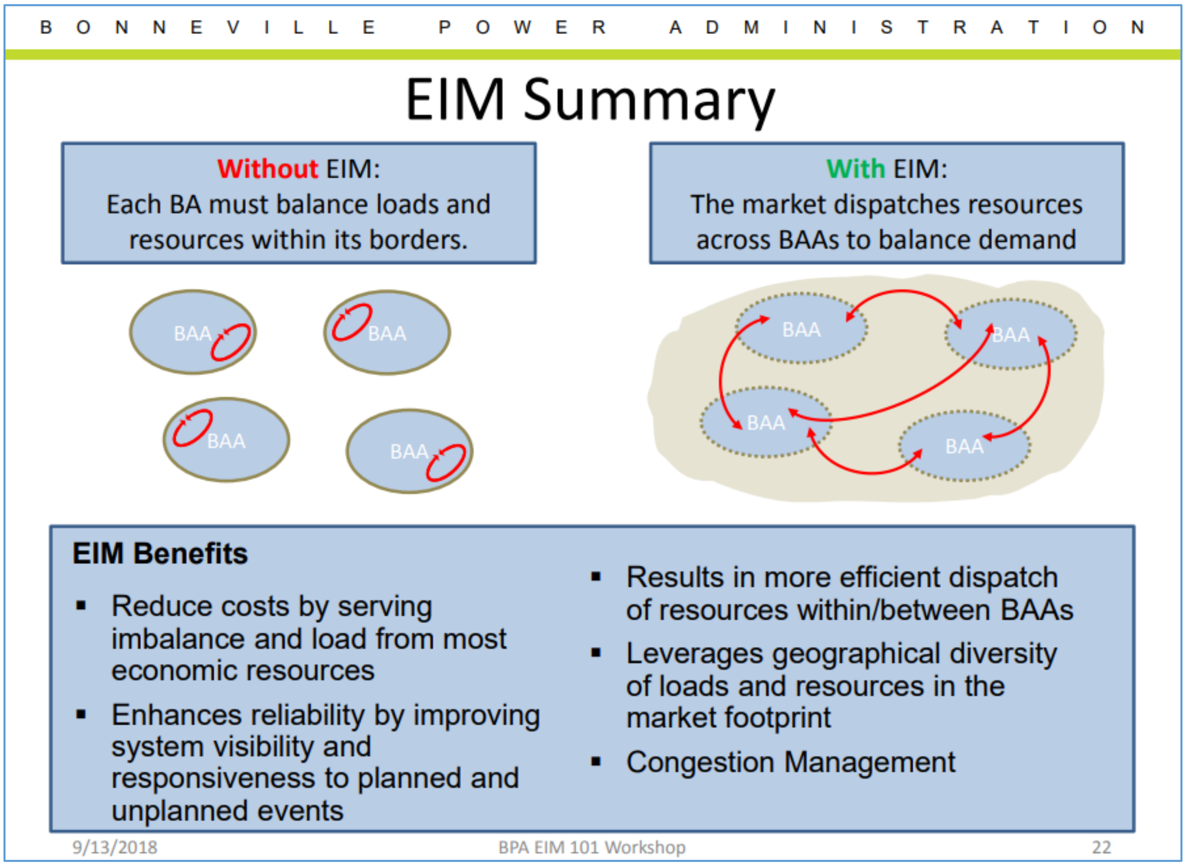
ii. Energy Imbalance Market (EIM)

An EIM is a voluntary real-time energy market that optimizes the imbalance of supply and demand of participating utilities using a centralized dispatch algorithm, typically at granular time intervals (every five minutes). In contrast to an RTO – the parameters of which were established by FERC Orders 888 and 2000 – the characterizations of an EIM in this report are based largely on past implementations. In its most basic form, an EIM consists of only the real-time energy market component of an RTO – finding the lowest cost resources to securely balance supply and demand in real-time using SCED. A summary of an EIM, and the benefits it provides, are shown in **Figure 3.** More details on this energy market are described in the next section.

Two EIMs have existed in the United States. In 2007, SPP implemented the first EIM, referred to as an Energy Imbalance Service, as an evolutionary step towards a more comprehensive RTO. More recently, SPP has reintroduced the Energy Imbalance Service as the Western Energy Imbalance Service, with the prospect of incorporating utilities to the west of its footprint.[38] Already, a number of utilities and cooperatives have signed on in anticipation of the market's launch in February 2021.[39]

The Western EIM, formed by CAISO in 2013, serves as the leading model of an EIM's potential. By enhancing the coordination of electricity generating resources over a large area, the Western EIM has generated over $1 billion in economic benefits to date.[40] Perhaps most salient is the Western EIM's ability to integrate variable generation. Since 2015 the Western EIM has prevented over 1,000 GWh of renewable energy curtailment, mitigating nearly 550,000 metric tons of climate-warming carbon dioxide.[41]

Figure 3 – Summary and Benefits of an EIM.



Source: Bonneville Power Authority supra note 53 at 22. In this figure "BA" stands in for Balancing Authority and "BAA" stands in for Balancing Authority Area.

iii. Energy Exchange Market (EEM)

An Energy Exchange Market (EEM) is an organized electricity market that automates bilateral transactions between utilities.[42] Like an RTO, the market operator collects information from participating utilities on their willingness to buy and sell electricity in real-time. The operator then uses all the information available to match buyers and sellers, facilitating gains from trade over any unscheduled transmission capacity. Unlike an RTO, an EEM does not carry out a system-wide optimization through SCED. Instead, the positions of individual energy traders are relied upon to identify production cost and savings and more efficient grid operations.

In the late 1990s, when organized electricity markets were first being designed in the US, there was a "raging" debate as to whether this exchange-based model or an "integrated" approach (using SCED) could best achieve least-cost reliable electricity.[43] In a simple economic model, both options can provide similar benefits. However, the electric power sector is complex.[44] Optimizing electricity production in real-time requires a sophisticated approach. Well-established, state-of-the-art optimization models now available to market operators suggest an integrated approach that solves

SCED has compelling advantages compared to an exchange-based one. [45] This is because the algorithms used by an integrated market can effectively identify the lowest-cost way to generate electricity while also handling the number of constraints of the electricity grid, like transmission access and congestion.[46] The integrated approach allows for dispatch to be jointly optimize with other features of the electricity grid that are important (like balancing reserves and unit commitment), is simpler for market participants, and supports competition through transparency.[47]

This exchange-based approach is more common in Europe than North America, where integrated markets have become the standard design.[48] Only one exchange-based market operates in the United States. Southern Company, the utility managing electric power in much of Georgia, Alabama, and some of Florida and Mississippi, facilitates real-time bilateral transactions through a platform called Southern Wholesale Energy.[49] Recently-proposed SEEM appears to be a similar exchange-based market.[50]

III. Overview of an Energy Imbalance Market in the Southeast

This section further details an EIM. It begins by outlining an EIM's operations and organizational structure. It then characterizes the existing institutions in the Southeast for context, before discussing the potential benefits of an EIM in depth. This includes a quantification of potential production cost savings, and a description of renewable integration and enhanced reliability. Finally, an EIM is compared to alternative reforms including a Southeastern RTO and what is known about the recent SEEM proposal.

A. Organization and Operations of an EIM

Hourly EIM operations are similar to the real-time market in an RTO. As an example, the Western EIM operated by CAISO includes a real-time market that clears every fifteen minutes and gives dispatch orders to electricity generators every five minutes. Seventy-five minutes before each 15-minute market, each utility must report to the market operator its "base schedule" and the economic bids of participating generators for that market. A utility's base schedule represents it plan to balance its own supply and demand within its balancing area; therefore, participation in an EIM does not necessarily alter a utility's approach to ensuring short-term resource adequacy.[51]

The economic bids of participating generators represent how much the parent utility is willing to increase or decrease the generator's output, and the market price the utility requires for it to do so.[52] The market operator uses the economic bids to find alternative ways to balance supply and demand relative to the base schedule. The Western EIM performs a number of "resource sufficiency tests" an hour before each 15-minute market to ensure no utility is relying too much on the EIM to balance supply and demand.[53]

Importantly, the dispatch outcome can differ from each utility's base schedule, as any participating electricity generator can be called upon to balance supply and demand in other balancing authorities – generating cost savings over other utilities' base schedule. Like an RTO's real-time market, settlement happens after the market clears. Each utility charged (or compensated) for the location-based market price and the quantity of electricity consumed (or produced) relative to their base schedule.

These real-time transactions can happen in parallel to long-run contracts, as illustrated in **Figure 4**. Suppose an electricity generator (Gen 1) has a contract to produce 100 MW power. If it participates in an EIM, and some other resource can produce the electricity more cheaply, the market operator will tell Gen 1 to reduce its output to the minimum possible amount while still remaining online. The cheaper electricity generator effectively serves the contract and is compensated the market price, while the more expensive electricity generator still receives the contract payment, but must buy electricity from the market to satisfy its contract. In this simple example, Gen 1 receives all of the benefits in the form of avoided production costs. Consumers would ultimately benefit if the production cost savings experienced by Gen 1 would reduce the retail rate for electricity.[54]

Figure 4 – Long Run Contracts in an EIM.

Production Cost and Bilateral Contracts in an EIM

Generator and Load Characteristics

Gen 1	
Production Cost	$40/MWh
Minimum Output	5 MW
Maximum Output	100 MW

Gen 1 has a long-term contract with Load A for 100 MW at $50/MWh

Gen 2	
Production Cost	$20/MWh
Minimum Output	5 MW
Maximum Output	100 MW

Load A	
Demand	100 MW
Willingness to Pay	$60/MWh

Outcomes with Bilateral Contracts

Gen 1 Contract Settlement Generates 100 MWh			
Revenue		Costs	
Contract	$5,000	100 MWh	$4,000
Profit: $1,000			

Gen 2 Contract Settlement Generates 0 MWh			
Revenue		Costs	
-	-	0 MWh	0
Profit: $0			

Load A Contract Settlement Consumes 100 MWh			
Benefit		Costs	
Contract	$6,000	100 MWh	$5,000
Net Benefits: $1,000			

Contract Net Benefits: $2,000

Outcomes with an EIM

Gen 1 EIM Settlement Generates 5 MWh			
Revenue		Costs	
Contract	$5,000	5 MWh	$200
		Market	$1,900
Profit: $2,900			

Gen 2 EIM Settlement Generates 95 MWh			
Revenue		Costs	
Market	$1900	95 MWh	$1900
Profit: $0			

Load B EIM Settlement Consumes 100 MWh			
Benefit		Costs	
Contract	$6,000	100 MWh	$5,000
Net Benefits: $1,000			

EIM Net Benefits: $3,900

A simple example showing how an EIM reduces production costs relative to bilateral contracts.

Utilities can elect to join an existing EIM or work to establish a new one.[55] The EIM itself is carried out by an independent not-for-profit organization—typically an RTO,[56] although a stand-alone EIM not connected to any RTO is feasible. In the case of the Western EIM, a utility joins the EIM after a formal process that includes cost-benefit analysis, training, and an implementation agreement.[57] The cost-benefit analysis component is crucial, as it allows utilities to consider both the potential benefits (and costs) under a number of alternative future scenarios.[58] This analysis so far has shown increasing benefits over time that outweigh the initial and ongoing costs.[59]

The market operator's actions are dictated by a "tariff" specifying the market rules.[60] In a traditional EIM, the tariff is established through a stakeholder process or by the EIM board, and ultimately approved by FERC. The standard governance structure of an EIM is based on the governance structure of an RTO, which values independence and stakeholder representation. The Western EIM governance structure, for example, consists of an EIM Governing Body of independent non-stakeholder members, an EIM Body of State Regulators to advise the EIM Governing Board, and a Regional Issues Forum for the general public to share opinions with the EIM Governing Board.[61]

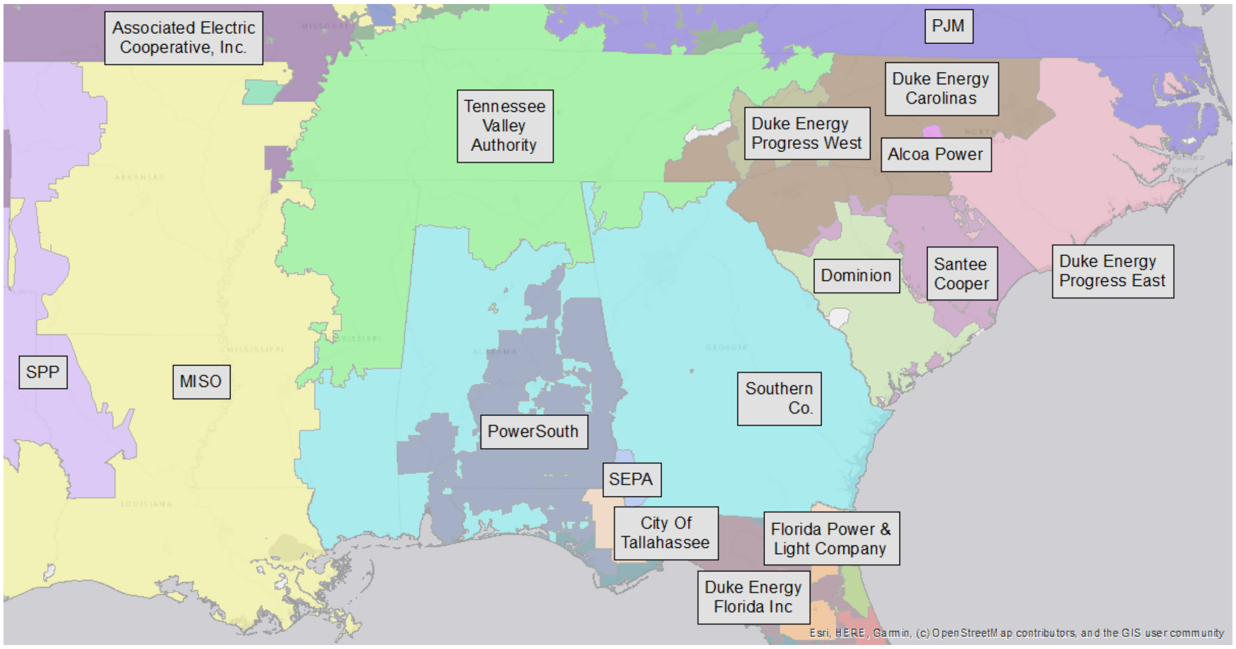
B. An EIM Compared to Existing Institutions in Southeast

The benefits of an EIM, in terms of encouraging cost-saving transactions between utilities in the Southeast, depend in part on the current level of trade. If utilities in the Southeast are already trading electricity when it is economically efficient and adequately accommodating fluctuations in renewable resource production, an EIM might not provide many incremental benefits. Aware of the benefits of trade, utilities in the Southeastern United States already exchange wholesale power. However, relative to the rest of the United States, the Southeast is characterized by less trade on average.[62]

In general, it is difficult to gauge whether or not electricity is traded efficiently because the details of bilateral transactions are often not publicly available. However, nearly all physical electricity sales in the region are done bilaterally, and so it is unlikely the production cost savings of large-scale joint-dispatch are being realized. [63] Further, of the trade that does occur, "long-term energy transactions are particularly prominent, compared to short-term transactions."[64] This suggests the short-run minute to minute balancing that is essential for the integration of variable renewable generation is not occurring at the level that is economically optimal.

Figure 5 shows a detailed map of utilities in the Southeastern United States. Although Duke Energy Carolinas (DEC) and Duke Energy Progress East/West (DEP, formerly Progress Energy Carolina) are technically separate subsidiaries of the Duke Energy, they carry out a joint dispatch agreement as a condition of their merger – effectively encouraging trade between the subsidiaries. The benefits provided by the joint dispatch are similar in nature to the production cost savings realized by an EIM. At the time of the merger, the joint dispatch agreement was anticipated to generate more than $70 million annually in consumer benefits on average.[65] This trade is especially beneficial given the extent of solar development in DEP, which can be exported and stored in pumped-hydro power plants available in DEC.

Figure 5 – Balancing Authorities in Southeastern United States.



Data comes from publicly available Homeland Infrastructure Foundation-Level Shapefiles. Author's map.

Duke Energy and PJM share a border and multiple 500 kilovolt (kV) transmission line connections, making their two territories physically interconnected at least in part. To manage activities that may influence each other, they share a Joint Operating Agreement.[66] This long-term contract provides coordination on congestion management and an agreement on the pricing imports and exports.[67] VACAR South and PJM also have a reliability coordination agreement which "provides for system and outage coordination, emergency procedures and the exchange of data."[68] These arrangements provide the fundamental basis for coordination, but in no way guarantee efficient trade.

Southern Wholesale Energy is an Energy Exchange Market that serves as a voluntary platform matching bilateral transactions at a market-set price. However, its current geographic scope, lack of independence, and market structure all suggest the benefits of Southern Wholesale Energy market are limited in comparison to a larger market that uses centralized dispatch. In particular, its exchange-based model does not effectively identify every cost-saving opportunity, taking into account transmission congestion and other system constraints. In addition, its limited participation and geographic scope suggests it does little to better integrate renewable generation than the status quo. Public data on Southern's website show there are few transactions in the market, far fewer than what is likely to be economically efficient.[69]

Relative to the existing institutions in the Southeast, an EIM has the potential to amplify the volume of trade by establishing a centralized platform that identifies the most cost-effective ways to balance supply and demand across participating resources. Compared to the existing Southern Wholesale Energy arrangement, an EIM consistent with past implementations would have market rules established through a stakeholder process, carried out by an independent board of governance, and enforced by the market monitor. What is more, an EIM with a larger geographic scope could reduce curtailment of renewable generation.

C. Potential Benefits of an EIM in the Southeast

There are three primary potential benefits of an EIM: a reduction in the cost of production, better integration of renewable energy, and improved reliability due to enhanced coordination and the pooling of reserves. This report quantifies the first of these benefits using an open-source dispatch model and publicly available data, and then characterizes the other two qualitatively.

i. Decreased Cost of Electricity

An EIM reduces the cost of producing electricity in several ways. Most significantly, through a centralized and transparent marketplace, the market operator identifies the resources with the lowest production costs and give them priority over other high-cost resources. In this way, the same quantity of electricity is produced as if there were no EIM, but the composition of resources used to generate electricity are the ones that cost the least. For example, an EIM in the Southeastern United States would allow Duke to easily buy power from other utilities or PJM when its own cost to serve additional demand is at its highest. Likewise, it could sell excess power during times in which it can produce surplus at a low cost.

The potential for cost savings is illustrated here using an open-source dispatch model of large fossil-fuel power plants.[70] In general, this model finds the lowest cost resources to generate enough electricity in a given area to match historical hourly demand. It does this using publicly available data on production costs, output, and minimum downtime. Interested readers are directed to the appendix for a more detailed description of the model and the modeling results.

To quantify the potential production cost savings, hypothetical EIM markets are defined by grouping together different balancing authority areas in the Southeast. For each hypothetical EIM scenario, the model identifies the least-cost dispatch of electricity generators across all balancing authorities in the EIM and the corresponding market price. This is done for every hour in 2018. With Duke Energy as an example, the potential cost savings are quantified as the change in the market price of electricity under the EIM scenario relative to the simulated price under Duke Energy's least-cost dispatch, multiplied by the quantity of electricity historically produced by Duke Energy.

This simulation assumes all resources of member utilities participate in the EIM, trade is frictionless within an EIM, and any resource not in the EIM cannot buy or sell electricity to an EIM member utility. For these reasons, these numbers should be considered as an upper bound of the production cost-savings achievable by an EIM.

Table 2 presents the potential cost savings relative to Duke Energy's joint dispatch in 2018. According to the model, Duke Energy's joint dispatch of large fossil-fueled plants costs $2.2 billion without trade. This number is similar to the actual reported costs for that year prior.[71] Had the dispatch been expanded to include all utilities in North and South Carolina through a transparent market, over $100 million in benefits, or 5% of production costs, would have been realized. This number grows substantially as more balancing areas are added to the dispatch. For example, an EIM with the Carolinas and PJM could have saved Duke Energy nearly $650 million in 2018.

Table 2 – Simulated Potential Production Cost Savings that Would Have Accrued to Duke Energy in 2018 Based on Alternative EIM Scopes.

Markets as Defined in **Table 4**	Potential Production Cost Savings ($ million in 2018)		Production Cost Savings as Percent of Total Cost	
	All Hours	Excluding 10% hours with largest cost	All Hours	Excluding 10% hours with largest cost
The Carolinas	$111	$80	5%	4%
North Carolina & PJM	$579	$344	26%	16%
The Carolinas & PJM	$647	$360	30%	16%
Southeastern EIM	$549	$276	25%	13%
Eastern EIM	$548	$262	25%	12%
SEEM's Footprint	$552	$277	25%	13%

Results are based on the reduced-order dispatch model and market definitions as described in the appendix.

These estimates are large relative to similar studies, but not unreasonably so in the context of North Carolina where there are a number of relatively expensive power plants. For example, recent high-level analysis of Duke Energy's North Carolina thermal generation facilities showed production cost savings of the order of 9 to 11%, larger than the typical production cost savings attributed to participation in an organized market (3 to 9%).[72] In addition, the joint dispatch agreement between Duke Energy Progress and Duke Energy Carolinas was estimated to generate over $70 million in annual benefits alone. Even larger regional coordination should provide even greater benefits, as this modeling exercise demonstrates.

Because the simulation assumes utilities do not trade at all in the baseline scenario, some may argue the numbers in **Table 2** are inflated because Duke Energy would likely buy electricity from a neighbor before using its highest cost resource. However, this alone is not likely driving the high estimates because the simulated production quantity is based on actual historical production by Duke Energy—which would be reduced had Duke Energy imported energy.

To address this concern, however, **Table 2** also quantifies the potential production cost savings while excluding the 876 hours (10% of all hours in 2018) with the highest production cost, presumably when Duke would have a found creative way to balance supply and demand. Even still, hundreds of millions of dollars in production costs savings could have accrued to Duke Energy in 2018 had it participated in an EIM.

In addition to production cost savings through better dispatch of resources, an EIM has the potential to better accommodate renewable energy and reduce curtailments as described in more detail in the next section. This generates environmental benefits, but also production cost savings as it increases the quantity of low-marginal-cost electricity produced from the same amount of installed renewable resource capacity.

These production cost savings are likely to be much larger than the cost of an EIM. For example, one-time startup costs for the Western EIM range from $2.1 million $14 million, and ongoing costs ranging from $1.3 to $3.5 million.[73]

ii. Reduced Curtailment of Renewable Generation

Renewable resources, like wind and solar farms, reduce the cost of electricity and help states meet their climate commitments by generating electricity at a low-cost and with zero carbon emissions. However, due to the inflexibility of many existing utility generators, particularly nuclear units, renewables become increasingly challenging to integrate at high penetration rates without some degree of curtailment. Without companion storage resources, renewable production is constrained by the weather, which at times can vary minute to minute. Electricity grids with high shares of renewable generation need to coordinate thermal resources to nimbly respond to changes in renewable electricity production by increasing or decreasing production. Otherwise, renewable generation must be curtailed, wasting low-cost zero-carbon electricity.

Curtailment of renewable generation is anticipated to be a serious issue in Duke Energy's future if the status quo persists. For example, recent modeling suggests up to 42% of renewable energy in Duke's footprint will be curtailed once solar penetration reaches 35%.[74] While installing flexible storage and replacing inflexible power plants can reduce the curtailment rate,[75] however, so too can better coordination between Duke Energy and the surrounding balancing authorities.

Combining the operations of balancing authorities, through an EIM or similar organized market, provides three benefits that allow for better integration of variable resources:[76]

1. Aggregating diverse renewable resources,
2. Aggregating the load, and
3. Aggregating the non-renewable balance of generation.

The first two benefits combine patterns of electricity production (supply) and load (demand), which reduces the variability in the quantity of electricity needed to balance the electricity grid. Ultimately, this reduces the quantity of reserves needed to maintain grid reliability, further reducing the cost to the grid of accommodating renewable generation.

For example, the peak demand for electricity occurs at different times in Raleigh, NC and Birmingham, AL, in part because they are in different time zones. As demand for electricity is declining after its peak in Raleigh, demand in Birmingham is likely to be on the rise. As a result, total demand for electricity across the two cities does not vary as much as if the two cities are considered on their own and independent from each other.

Likewise, aggregating diverse renewable production profiles reduces the overall variability in aggregate renewable electricity production. This is because cloud cover in Duke Energy's footprint does not necessarily mean cloud cover in Southern Company's footprint. What is more, when the sun sets in eastern North Carolina, it is still shining in Western Kentucky. By combining the output from many different renewable resources across a wide geographic area, total production from renewable energy is less volatile. This is especially apparent compared to aggregate production in Duke Energy's footprint alone.

This general concept, in the context of the Western United States, is illustrated in **Figure 6**.[77] As the renewable energy penetration level increases, so too does the variability in renewable energy production as a fraction of total electricity demand. In **Figure 6**, each colored line represents a different footprint. Smaller footprints (like western Colorado "CO-W," Wyoming "WY," and New Mexico "NM") show a strong positive relationship between renewable energy penetration and variability. In comparison, larger footprints with more diverse assets (like most of the western United States "WECC," and a larger portion of the listed states "Footprint") show a much weaker relationship between renewable energy penetration and the variability of renewable generation as a fraction of energy demand. The largest geographic area ("WECC") even shows more renewable generation *decreases* the variability of renewable generation as a fraction of total output.

Figure 6 – Renewable Penetration, Variability, and Footprint Size.

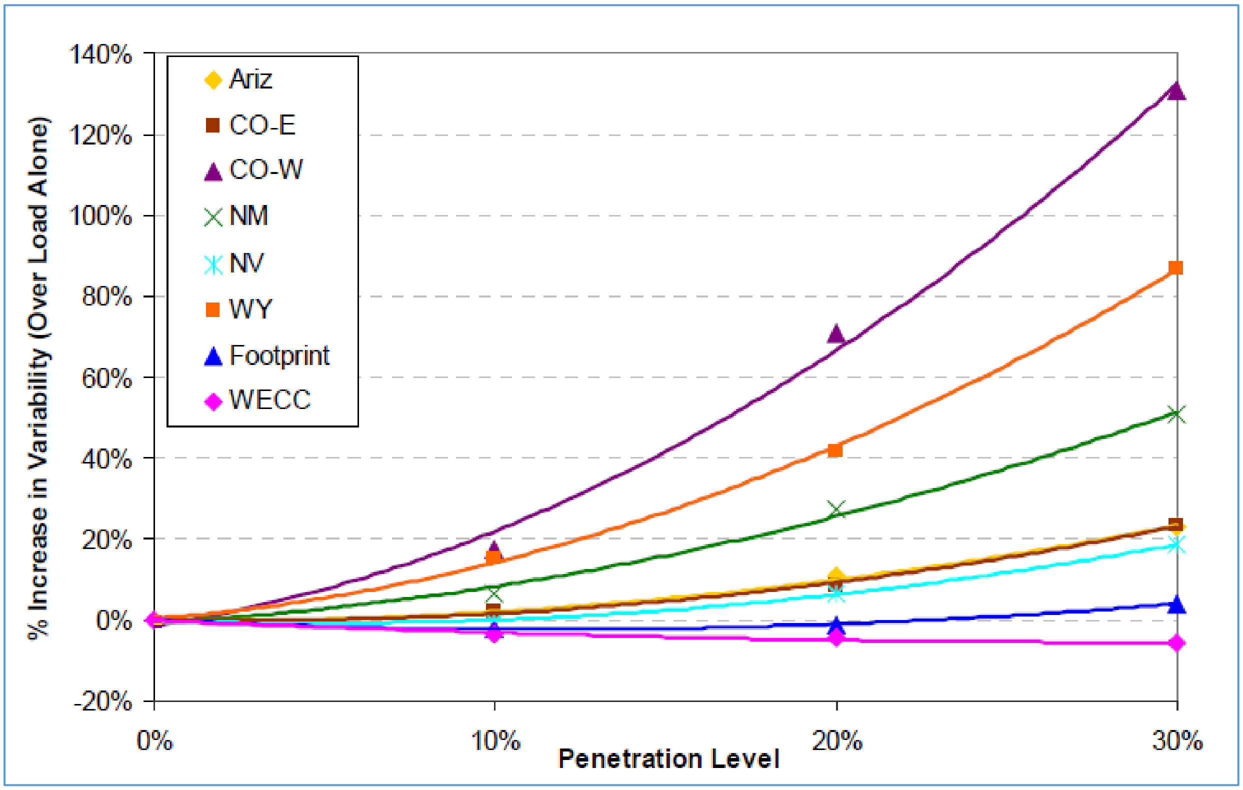


Figure showing increased renewable generation variability as a percent of demand (y-axis) with higher renewable energy penetration (x-axis) in the Western United States. Large footprints ("WECC" and "Footprint" in this setting) are associated with lower variability at higher levels of renewable energy penetration. Image Source: GE ENERGY, supra note 76 at 83.

Finally, aggregating non-renewable generation allows for the market operator to respond more easily to the remaining fluctuations in renewable supply and demand by having a larger pool of resources to potentially call on if needed. This is particularly helpful to the extent that the market pools together a larger number of fast-ramping generators. By doing so, the market operator can access the fastest-ramping least-cost units to balance renewable generation-induced fluctuations in supply. This can reduce renewable energy curtailments, and decrease the cost of balancing supply and demand.[78]

This is important in North Carolina, where both recent changes to renewable procurement and ambitious commitments to install more renewable energy suggest there can be significantly more curtailments in the future. As already mentioned, curtailment rates could reach as high as 42% without any interventions.[79] At the same time, Duke Energy now requires new solar power purchase agreements (PPAs) to provide for up to 10% uncompensated curtailment, a rate it may seek to increase in the future in the absence of an EIM or similar market.[80] This is in contrast to the diminishing number of projects being built under the Public Utility Regulatory Policies Act, which does not allow for curtailment of renewable resources except in cases of system emergency.

iii. Improved System Reliability

Reliability generally refers to the ability to meet the electricity needs of end-use customers, even when unexpected factors reduce the amount of electricity available.[81] An EIM generates reliability benefits over the traditional organization of electricity production because it aggregates all available information from market participants, and automates the response to unanticipated electricity production shortfalls.[82] This is accomplished by solving the SCED problem and short-interval (5-minute) dispatch. Ultimately, SCED allows for resources to be re-dispatched to solve electricity production shortfalls more quickly, and for it to be done in the most cost-effective way possible (considering transmission and generation constraints).

In addition, by pooling resources to balance supply and demand, an EIM allows for utilities to buy power during periods of peak demand or unexpected demand shortfalls rather than maintaining all of the resources necessary to ensure reliability. In this way, an EIM eliminates the need for many redundant balancing reserves. Instead of each utility having its own natural gas power plant on standby, for example, only a few are needed to satisfy any contingencies for the entire EIM, as reserves can more easily be imported across existing transmission lines when needed.[83]

These reliability benefits imply utilities need not invest as much in new capacity to balance supply and demand in an EIM as they would without an EIM. This is not to say an EIM is a substitute to resource adequacy investments, but that an EIM could be a substitute for investments motivated by reliability concerns. As a result, ratepayers save on capital costs and on the return they would ultimately pay the regulated utility. This is especially important given the potential of new fossil-fuel investments to eventually become stranded assets under a strict climate policy.[84]

These benefits are important for renewable integration as well. In regulated Southeast jurisdictions like Duke Energy Carolinas, Duke Energy Progress, and Dominion Energy South Carolina, variable renewable resources are now required to pay "integration charges" for every megawatt-hour of output.[85] Other Southeast utilities may impose these charges going forward, and utilities already imposing these charges may attempt to increase them over time. Utilities claim these integration charges are intended to represent the additional reserve capacity costs necessary to balance the variable output of renewable resources. Through better coordination of supply and demand with neighbors, integration charges need not be so large.

For example, by simply combining Duke Energy Carolinas and Duke Energy Progress's footprint when determining the dispatch, as an EIM would do on a much larger scale, integration costs decreased by 15% relative to treating each footprint separately.[86] These cost savings are remarkable because they are due to better coordination alone, not a costly or unproven technology. This demonstrates, on a small scale, the potential benefits of an EIM. [87]

It is likely that better coordination across the Southeastern U.S. could greatly diminish or even eliminate the capital costs required for balancing new renewable generation. For example, when the Northern States Power Company (NSP) Balancing Authority became integrated in MISO's real-time SCED dispatch in 2005, it had approximately 400 MW of wind generation and maintained approximately 80 MW of regulating reserve capacity.[88] Over the next four years, NSP tripled its wind generation capacity to 1,200 MW and maintained reliability compliance with NERC without having to adjust its regulating reserve capacity at all.[89] This experience in not uncommon. For example, the participants in the Western EIM reduced their required flexible ramping capacity by roughly 50%, compared to what they would require operating on their own.[90]

D. An EIM Compared to Alternative Reforms

An EIM is not the only option for reforming the organization of electricity production in the Southeast. This section generally compares an EIM to a Southeastern RTO, as well as public information currently available about the SEEM proposal.

i. An EIM compared to an RTO

An EIM's management of the electric power grid within its territory is not nearly as comprehensive as that of an RTO. In this sense, an EIM does not satisfy RTO fundamental characteristics #3 or #4 listed in **Table 1**, "Operational Authority" and "Short-term Reliability." As a result, many of the benefits of an RTO are not realized in an EIM. For example, coordinated capacity and transmission planning, standardized interconnection processes, more thorough market monitoring, unit-dispatch in a day-ahead market, and more complete ancillary services are all not traditionally realized in an EIM. **Table 3** characterizes traditional RTOs and EIMs, as well as other market arrangements, across a number of different measures.

An EIM and RTO both reduce production costs through SCED, facilitate the integration of renewable generation, and better coordinate operations, resulting in less capital investment and better reliability during times of peak demand. Because an EIM is voluntary, however, there might be less participation, and hence, it will likely yield benefits of smaller magnitude.

A recent report from Energy Innovation and Vibrant Clean Energy demonstrates the large potential benefits of a Southeastern RTO in comparison to the status quo.[91] In North Carolina specifically, a Southeastern RTO that includes competitive procurement new capacity, coordinated transmission planning, and centralized dispatch using SCED across the entire Southeast can generate approximately $2,400 million in economic benefits in 2025.[92] Two-thirds of these potential benefits (roughly $1,600 million) are driven by efficient capacity investment in low-cost (renewable) resources.[93] This can be achieved in an RTO or through a unbiased competitive procurement process overseen by vertically integrated utilities, but would not be part of an EIM. The remaining potential benefits (roughly $800 million) are driven by organized transmission planning, optimized use of distributed energy resources, and centralized SCED across the Southeast. The centralized dispatch benefits can be achieved under an EIM as well as an RTO.

Although an RTO can generate more benefits than an EIM, an EIM generally leaves greater authority in the hands of state regulators to administer features of the grid which they might find important. This can be consequential in states where state regulators are expected to be a major instrument of public policy – by, for example, requiring utilities to retire fossil-fuel power plants and replace them with clean alternatives. Because every interstate RTO is FERC-jurisdictional, the design of any component of an RTO will reflect FERC's perspective and theory on how that component should be implemented. This can create a conflict if an RTO requires member utilities to participate in a feature of the RTO that overlaps with state regulators' policy agenda and FERC's perspective is at odds with the goals of state regulators.

Two recent FERC decisions about capacity markets provide clear examples of how tension can arise between state and FERC policy. In December 2019, a decision regarding PJM's capacity auctions spurred Illinois, Maryland, and New Jersey to explore alternatives to participation in PJM's capacity market.[94] Similarly, a February 2020 decision regarding NYISO's capacity market led the New York Public Service Commission to commission an analysis of alternative approaches that would better align with the state's aggressive clean energy agenda.[95] Although this potential for tension might seem like a downside to RTO participation (from the perspective of state policymakers), RTOs do not inevitably operate in ways that conflict with state regulators' goals. The capacity market conflict highlighted above, for instance, has only occurred in RTOs where capacity market participation is mandatory—three out of seven—and it is possible that changes to FERC's policy in those RTOs will come to align with the goals of state regulators.

ii. An EIM compared to SEEM

What little is known about SEEM suggests that it will be an improvement over the status quo; however, it will not generate as many benefits for the Southeast as either an EIM or a Southeastern RTO.[96] Broadly, the basic market design of SEEM is an EEM (like Southern Wholesale Energy) which automates bilateral transaction between market participants based on available transmission capacity. This market design is not likely to identify the same cost-savings opportunities as an EIM that uses an "integrated" approach that solves the SCED problem. This is because the bilateral approach does not directly optimize the system considering transmission and generator constraints, nor does it directly price the cost of these constraints. Furthermore, it does not have the situational awareness to re-dispatch in response to short-run fluctuations in supply.[97]

It appears that SEEM's market will clear every fifteen minutes. This is better than existing long-run contracts and the Southern Wholesale Energy market, which clears every hour.[98] It is unclear whether or not SEEM's dispatch will be determined every five minutes, as is common in all RTOs and EIMs. Little is known about SEEM's proposed governance structure or whether there will be any market monitoring. Typical implementation of an EIM, however, includes an independent governance and market monitoring. Neither a traditional implementation of EIM or what is known of SEEM would suggest the reform would interfere with state-level resource adequacy planning like an RTO might.

Preliminary modeling suggests SEEM will generate $40 to $70 million in production cost savings over its entire footprint in the year 2027.[99] The modeled benefits are slightly larger in a "carbon-constrained" future associated with more variable renewable energy. These benefits appear small in comparison to similar potential reforms to Duke Energy and North Carolina alone. For example, this report shows an EIM could have saved Duke Energy hundreds of millions of dollars in 2018, the joint dispatch of Duke Energy Progress and Duke Energy Carolinas was supposed to generate over $70 million in annual benefits, and a Southeastern RTO has the potential to generate $2.4 billion in benefits by 2025.[100]

The estimated cost of SEEM, $5 million initially and $1 to $3 million annually, is smaller than the likely cost of an EIM (or a Southeastern RTO).[101] However, the benefits of SEEM are smaller as well. More analysis should be done to determine which arrangement can generate the most net-benefits for the Southeast, however, preliminary evidence suggests SEEM is the least net-beneficial of the potential reforms possible in the Southeast.

If a study finds benefits to an organized electricity market, state legislatures or public utility commissions can require utilities to form or join such a market. To maximize the benefits of an EIM (which allows for *voluntary* participation of power plants owned by member utilities), regulators or legislatures can require utilities to at least make a good faith effort to submit their resources to the market for consideration.

Regulators also have an important role in the rate-making process if the intent is for consumers, not utilities, to benefit from an EIM. Without properly accounting for the change in production costs, it would be possible for utilities to capture most of the benefits of an EIM, and to pass on little of the production cost savings to industrial, commercial, or residential consumers.

Table 3 – Comparing Alternative Arrangements for the Organization Electricity.

	Bilateral Contracts	***Power Pool***	***EIM***	***RTO***
Price Signals	Limited	Limited	Transparent	Transparent
Transparent Generation Data	No	No	Possible	In Aggregate
Dispatch	Utility Dispatch	Tight: Joint Dispatch Loose: Utility Dispatch	SCED of Participating Generators	SCED of All Generators
Unit Commitment	Possible	Possible	Possible	Yes
Voluntary Participation	Depends	Depends	Yes	No
Demand-Side Programs	Utility	Utility	Utility & Possible by Market	Utility & Market
Renewable Benefits	Depends	Depends	Larger Territory	Larger Territory
Ancillary Services	Depends	Depends	Some (flexible reserves)	Several (spinning, regulation)
Capacity Planning	State Regulator	State Regulator	State Regulator	RTO or State Regulator
Transmission Planning	Planning Region	Planning Region	Planning Region	RTO Planning Region, with State Engagement via Public Policy Projects
Interconnection Process	Utility	Utility	Utility	RTO
Stakeholder Process	N/A	Depends	Transparent	Transparent
Market Monitoring	No	Depends	Market Monitor	Independent Market Monitor
Governance	Utility with State Regulator Oversight	Depends	Governing Board	Governing Board

From left to right, the arrangements increase in their ability to amplify trade. SEEM is not included in this table because not enough is known at the moment. However, what little is known about SEEM would place it between a Loose Power Pool and an EIM. Of most importance, SEEM does not use SCED to determine dispatch, but instead uses automated bilateral transactions.

Currently, a number of utilities in the Southeast are separately pursuing the formation of an energy market, SEEM. This exchange-based market is not an EIM in the sense that it is not based on centralized dispatch, nor is it a more comprehensive RTO. Soon, the utilities involved are likely to file a tariff with FERC which will better outline their proposal. Duke Energy claims the formation of SEEM will not preclude the formation of an RTO at some later date, [102] and so will likely not preclude an EIM either. However, establishing SEEM only for it to be shortly upended by a better designed EIM or more comprehensive RTO would be a waste of resources for both the participating utilities and FERC. For this reason, it is important for the developers of SEEM to participate in an open dialog with all stakeholders and regulators to ensure whatever energy market is developed can generate significant benefits to the Southeast and achieve the public policy goals in the region.

Finally, incorporating utilities in the Southeast into only a component of the PJM RTO, like PJM's real-time energy market, will require discussion between PJM and the relevant utilities. Policymakers can encourage utilities to participate in this dialog and even participate in the discussion themselves. Ultimately, the dialog should be intent on establishing a Memorandum of Understanding between PJM and the participating utilities—much like the one between CAISO and PacifiCorp that led to the creation of the Western EIM.[103]

A. Market Scope Consideration

There are a number of factors to consider when determining the scope of an EIM, including the desired geographic extent, the fuel mix of potential participating utilities, the existing market constructs, and existing transmission infrastructure.

In terms of integrating renewable generation, the larger the footprint the better. With a larger footprint come more diverse load and renewable generation patterns, and subsequently less variability in required production from non-renewable resources. In addition—the more inversely correlated load and renewable generation patterns are, the better. For example, combining crepuscular wind generation from the Midwest (produced more often at dawn and dusk) with diurnal solar generation (produced more midday) results in more constant renewable generation throughout the day. Likewise, connecting regions in different time zones would reduce variability in demand for electricity and supply from solar energy.

The modeling of potential production cost savings in this report suggests that an EIM operating through PJM and including all of the Carolina utilities could generate the most benefits for Duke Energy customers. The second most beneficial scope for Duke Energy included only Duke Energy and PJM. Adding to the benefits of this arrangement, PJM has spent decades developing a comprehensive and well-functioning real-time energy market. Adding new members to the real-time market operations is not completely costless, but is likely to be much less costly than building a whole new energy market platform with from the ground up. For these reasons, an EIM extension of the PJM RTO may be one of the best options for the Southeast.

The fuel mix of utilities participating in an EIM is another important consideration. It is not always the case that adding more utilities to an EIM will decrease the average production cost within the EIM, even if doing so does generate production cost savings. For example, adding a utility with high-production cost and high demand will increase the average cost of electricity. This is not to say both regions do not experience gains from trade. Instead, the lower cost region can now export more electricity, and the higher cost region has access to lower cost electricity. Although all regions benefit from this arrangement, they do so in different ways. This highlights the importance of detailed, unit-level modeling, to quantify exactly who benefits the most from an EIM and how those benefits are realized across several market scopes.

In addition, some types of resources can better accommodate renewable generation than others. For example, pumped-hydro power plants, which are more common in the western part of the Southeastern United States, can serve as storage of potential energy during times of excessive renewable generation. An EIM could jointly optimize production from renewable resources and pumped-hydro storage. Because renewable resources are low-cost, it is more likely the pumped-hydro power plants would store energy from renewable resources than from coal-power plant. This would generate both economic savings of increased low-cost electricity production and environmental benefits of zero-carbon electricity production. For this reason, it is important to consider non-fossil resources and their production profiles when quantifying the potential benefits of a wholesale energy market.

Finally, existing transmission infrastructure is an important consideration. Currently, there are high-voltage (500 kV) transmission lines in the Southeast connecting Duke Energy to PJM through Dominion Energy and Appalachian Power Co., and to Georgia Power. This suggests that transmissions lines are an important consideration, but potentially not a limiting factor in determining which regions to include in an EIM.

B. Market Design Considerations

The design and technical details of an energy market can have significant ramifications for the benefits, costs, and outcomes realized. Generally, it is best to include both a real-time market for balancing reserves, a day-ahead market for unit-commitment, and a market for ancillary services if possible.[104] Although the last two are not essential to the design of an EIM, they should be considered as they can provide additional benefits over a real-time market for balancing reserves.

In the real-time market, an organized dispatch solving a well-considered problem like SCED is best. This integrated approach can identify all potential cost-saving opportunities while being mindful of, and directly pricing, system constraints like transmission congestion.[105] The integrated approach is also better at handling more complex problems, like co-optimized day-ahead unit commitment, should they ever be incorporated into the EIM.[106] Finally, a transparent integrated approach provides opportunities and protections for the smaller generators through an unbiased competitive structure.[107]

The more granular a time period in which the market clears, and in which dispatch instructions are given, the better. In the US, it is common to have 5-minute market periods (where generators can adjust their bids and the markets clear financially) and dispatch instructions (which are used to respond to extremely short run changes of the electricity grid).[108] This granular dispatch over time is essential for markets with large shares of renewable generation, as it increases flexibility in system operations minute to minute.[109]

Similarly, granular "nodal" prices that vary geographically are better than market-wide prices that are common in exchange-based markets. This is because location-based pricing incentivizes demand response and distributed generation where the cost (hence price) of electricity is the highest. In addition, location-based prices can help identify locations for efficient transmission and generation capacity investment, as it directly prices in the cost of transmission constraints and electricity delivery.[110]

Finally, an organized electricity market can only provide benefits to stakeholders insofar as it adheres to market principles of unbiased treatment of resources and reflects the preference of the public which it serves. For this reason, it is essential the market includes transparent and public price signals, public information on market operations, an external market monitor, and an independent governance system that includes stakeholder participation. A number of RTOs have successfully designed these features, and potential energy markets in the Southeast should look to them as an example. To date, it is unclear whether the SEEM proposal will include any of these design features.

C. Environmental Considerations

Finally, an EIM can provide environmental benefits by reducing curtailments from existing renewable generation while also reducing the cost to integrate renewable generation. Increasing the production from installed renewable generation capacity is a great benefit to society, as it reduces climate-warming greenhouse gas emissions and harmful local air pollutants from fossil-fuel electricity generation. In addition, reducing all barriers to renewable generation – such as integration charges – can ensure they are deployed at a scale that is compatible with state policy goals.

It is important to note, however, an EIM is far from sufficient to accomplish anything other than modest goals to reduce greenhouse gas emissions. In fact, because organized energy markets can increase the production from low-cost energy resources, it is possible the existence of an EIM can increase production from pollution intensive power plants if the pollution intensive plants can operate at a low-cost.[111] In the context of Duke Energy in the Southeast, however, the modeling in Section IV suggests the opposite. It shows an EIM reduces electricity production from Duke Energy's fossil-fueled power plants—especially older and more expensive coal-power plants. That modeling exercise doesn't identify which electricity generators are replacing Duke's fossil fuel power plants, so it is possible Duke Energy is simply importing cheaper fossil-fuel energy from another utility. However, more detailed modeling of a hypothetical Southeastern RTO, which similarly identifies the lowest-cost dispatch, shows an energy market can reduce greenhouse gas emissions significantly relative to the status quo because coal power plants are more expensive than renewable alternatives.[112]

Fundamentally, an EIM is no substitute for a well-designed climate policy. However, an organized electricity market is compatible with, and possibly even a complement to, many of the state-specific climate policy options.[113] For example, implementing a carbon price in the electric power sector or establishing a cap-and-trade program would both increase the cost of carbon-intensive electricity production (i.e. coal-fired power). Utilities subject to these types of programs have an incentive to report their pollution charges to the EIM market operator, and as a result, the EIM market operator would choose to dispatch those now higher-cost carbon-intensive power plants less often.

Ever more so, a wholesale electricity market can be designed to incorporate climate damages of electricity imported into (or exported out of) the state through border adjustments.[114] This mechanism prevents emissions leakage – whereby a policy in one region that is intended to reduce pollution is undermined by the import of pollution-generating products from outside that region. Emission leakage is a real concern in the electric power sector because of the potential of interstate electricity trade. Should a future climate policy in the southeast price carbon dioxide in some states but not others, an EIM (or RTO) can mitigate emissions leakage that would undermine the effectiveness of that policy.

IV. Conclusion

Much has changed in the electric power industry since Samuel Insull first championed the regulation of a vertically integrated monopoly utility. Now, advanced algorithms coordinating electric power production amongst utilities and across wide geographic areas can generate sizable economic, environmental, and reliability benefits. These benefits are not only supported by basic economic theory but have been demonstrated in nearly every part of the United States except for the Southeast.

This report establishes that a well-functioning electricity market can generate significant value for the Southeastern electric power sector by reducing production costs, integrating renewable generation, and improving reliability through enhanced coordination. In particular, this report advocates that a wholesale electricity market in the form of an EIM is a great first step towards a more efficient electricity grid in the Southeast. This market structure provides several of the benefits associated with more traditional RTOs, can be implemented at a relatively low cost, and guarantees state regulators retain authority over some features of electric power that they might consider to be important.

These potential benefits of an EIM can be large. For example, novel simulations show that the potential production cost savings resulting from Duke Energy participating in an EIM could have been hundreds of millions of dollars in 2018. As more renewable generation is added to the electricity grid, inter-utility coordination is more important than ever. It can reduce curtailments of renewable energy, increasing the productivity of installed renewable resources. And, better coordination through an EIM can reduce or nearly eliminate the cost of integrating more renewable generation.

Finally, this report provides several important considerations and guidelines for creating a wholesale energy market in the Southeastern United States. These considerations are important as utilities in the Southeast explore alternative arrangements to trade electricity, like the recently proposed SEEM. There are several reasons to believe an EIM extension of PJM might be the best possible option for Duke Energy at the moment, given potential cost savings and the existing, well-functioning, real-time market in PJM. Regardless, an integrated market with short-interval dispatch, location-based pricing, an independent market operator and monitor, and stakeholder engagement should be a part of whatever market is implemented in the Southeast.

At this moment, however, the most important action to take is more research. State policymakers and utilities alike should continue to pursue analysis that quantifies the costs and benefits of alternative arrangements, including an EIM. For state legislatures, this might include passing legislation to at least study the issue further. For utilities interested in reform, it is important to do analysis and modeling in a transparent way that involves a dialog with all relevant stakeholders.

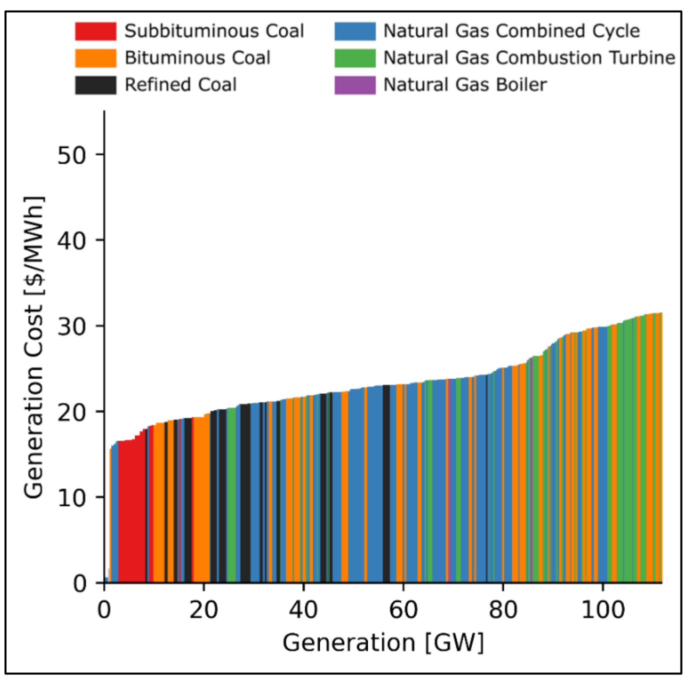
Appendix: Reduced-Order Dispatch Model

This report uses the open-source reduced-order dispatch model to quantify the potential production cost savings of better coordination amongst electricity power plants through a market construct like an EIM.[115] This model uses publicly-available data on historical fuel costs and electricity production to simulate which combination of electricity power plants can generate the same electricity as was historically produced, for every hour. It does this while minimizing production costs across all electricity generators in a geographic area and respecting historical downtime requirements of thermal generators. Interested readers are directed to Deetjan & Azevedo *supra* note 70.

The model accomplishes this by constructing a "merit-order" for every week on the sample year, which ranks large fossil-fuel electricity generators according to their cost to produce electricity.[116] An example merit-order, of large thermal electricity generators in North Carolina, South Carolina, and PJM during the first week of August is shown in **Figure 7**. This merit-order varies week-to-week according to publicly available fuel prices and observed plant-specific efficiency rates.

For every hour in the sample, the model determines which combination of resources could have produced the same quantity of electricity as historically produced by large fossil-fuel electricity generators, but at the lowest possible price, by finding where the merit-order intersects with the demand for large fossil-fuel generation. In doing this, it respects weekly limits on minimum and maximum output, as well as required down time of larger fossil-fuel power plants. Although relatively simple, this model does a good job capturing many features of the electric power system. This model is not able to model the dynamics of unit-commitment, non-fossil resources, or transmission capacity constraints.

Figure 7 – Merit-order from Reduced-Order Dispatch Model.



This merit-order reflects the cost, and maximum production output, of all large electricity generators in North Carolina, South Carolina and PJM for the first week of August in 2018

Because the merit-order represents the marginal cost to produce electricity for a corresponding quantity of fossil-fuel energy demanded, the cost of the most expensive electricity generator operating in an hour is the one that determines the market price. This price reflects only the cost of energy, not transmission losses or transmission congestion costs. As a result, this model does not capture all features of the electric power sector. Nonetheless, comparing historical electricity prices to prices simulated from the model suggests it is appropriate for broad scenario analysis.[117]

The scenarios presented in this report separately solve for the hourly dispatch of electricity generators to minimize costs using data from 2018. They do so multiple times, varying the geographic scope – defined in terms of balancing authority footprints listed in the EIA – as shown in **Table 4**.

Table 4 – Market Definitions in Dispatch Simulation Model.

Scenario	Balancing Authorities Included
Reference Case	Duke Energy Carolinas, Duke Energy Progress East, Duke Energy Progress West.
The Carolinas	**Reference Case** + South Carolina Electric & Gas, South Carolina Electric & Gas Company, South Carolina Public Service Authority, Alcoa Power Generating, Inc. (Yadkin Division).
North Carolina & PJM	**Reference Case** + PJM
The Carolinas & PJM	**The Carolinas** + PJM Interconnection, LLC
Southeastern EIM	**The Carolinas** + Southern Company Services, Inc., Southeastern Power Administration, Tennessee Valley Authority, PowerSouth Energy Cooperative
Eastern EIM	**Southeastern EIM + PJM**
SEEM's Footprint	**Southeastern EIM –** Southeastern Power Administration + Associated Electric Cooperative, Inc., Louisville Gas and Electric Company and Kentucky Utilities

Electricity generators within each balancing authority are identified according to EIA data.

The baseline scenario includes 74 fossil-fuel electricity generating units owned by Duke Energy, of which approximately 75% are powered by natural gas. The hourly dispatch of these electricity generators is determined assuming Duke Energy Progress and Duke Energy Carolinas are carrying out a joint dispatch that minimizes the cost of producing electricity within their footprint. Trade between Duke Energy and neighboring utilities is assumed to be equivalent to historical trade, so that the quantity produced by all of Duke Energy's large fossil-fuel resources is the same in the simulation and historical data. The result in the baseline scenario is 8760 hourly dispatches, with a single price of energy across all of Duke for every single hour simulated.

For each EIM scenario, electricity generators from neighboring balancing authorities that are now members of the EIM are added to the model and simulation procedure. The output is a single energy price for every hour in 2018 for each EIM scenario. Underlining this energy price are the assumptions that all electricity generators owned by balancing authorities in the EIM are jointly dispatched to minimize the cost of energy, there is frictionless trade between all utilities in the EIM, and trade between utilities in the EIM and outside the EIM is accurately reflected in the historical data.

For each scenario, the potential production cost savings of an EIM are calculated as the sum over all hours of the difference between the reference case energy price and the EIM scenario energy price, times the quantity historically produced by Duke Energy. This calculation assumes that Duke would have to buy from the wholesale market enough electricity to match their historical production, less the electricity they produced in each EIM scenario.

To be explicit, for each market scenario m the production cost savings are:

$$Production\ Cost\ Savings_m = \sum_t Production_t \cdot (ReferencePrice_t - ScenarioPrice_{mt}).$$

Here, $Production_t$ is the historical production of Duke Energy in hour t, and likewise $ReferencePrice_t$ is the simulated energy price of Duke Energy in hour t.

In the refence case simulation, Duke Energy produces a total of nearly 9 GWh of electricity at a price of 33 \$/MWh on average. The quantity produced by Duke Energy in the baseline scenario ranges considerably from nearly 3 GWh to nearly 20 GWh, depending on the hour. This seems small relative to historical data by all electricity generators owned by Duke Energy, but that is only because the model does not simulate electricity production from nuclear or renewable electricity generators. The energy price in the reference case simulation ranges from 23\$/MWh to over 100 \$/MWh.

The average price of electricity in the EIM scenarios is uniformly less than 33 \$/MWh. For example, in The Carolinas & PJM scenario, the simulated energy price is 26 \$/MWh on average. In every alternative scenario, Duke Energy produces less electricity from both its coal and natural gas electricity generators. The reduction in coal powered electricity production is nearly always twice, if not three times, as much as the reduction in natural gas-powered electricity production across all EIM scenarios. In particular, every EIM scenario sees nearly a GWh reduction in electricity produced from the Belews Creek, Marshall, and Cliffside coal power plants on average. As currently modeled, it is unclear which electricity generators in neighboring balancing authorities are replacing these electricity generators.

The modeling results imply Duke Energy must import additional electricity across transmission lines. In reality, there are physical limits to how much electricity can be transferred along the existing transmission infrastructure. Across the alternative EIM scenarios, the simulation results suggest Duke energy must import nearly 2 to 6 GWh on average. Although this is a significant amount of electricity to import, it is not impossible (or even unlikely) for Duke Energy to import this amount of electricity. For example, the EPA Power Sector Model specifies the general Carolina region can transfer nearly 9 GWh through existing transmission lines, including a 3 GW connection with Southern Energy and nearly a 6 GW connection to PJM.[118] If anything, this highlights the importance of additional transmission capacity in generating production cost savings through better dispatch and trade.

References

1 GREGORY MANKIW, PRINCIPLES OF MICROECONOMICS at 6-7 (4th ed. 2006). (Principles #5 & #6).

2 Hereafter, ISOs and RTOs will be collectively referred to as RTOs. Although there are minor differences between ISOs and RTOs (for example RTOs are generally considered to be larger and have a more established role in transmission resource planning), they are effectively identical for the purpose of this report. About two-thirds of electricity demand in the United States is cleared in an organized electric market. *See*, FED. ENERGY REG. COMM'N, ENERGY PRIMER: A HANDBOOK FOR ENERGY MARKET BASICS 39 (2020).

3 *See*, Jennifer Chen, *Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States*, Nicholas Institute for Environmental Policy Solutions (2020). (Discussing EIMs and RTOs. And suggesting an RTO may have provide benefits than an EIM.); *See also,* Eric Gimon et al., *Summary Report: Economic and Clean Energy Benefits of Establishing a Southeast U.S. Competitive Wholesale Electricity Market*, Energy Innovations and VCE (2020). (Quantifying a Southeastern RTO's potential benefits.).

4 *See* SAMUEL INSULL, CENTRAL-STATION ELECTRIC SERVICE: ITS COMMERCIAL DEVELOPMENT AND ECONOMIC SIGNIFICANCE AS SET FORTH IN THE PUBLIC ADDRESSES (1897-1914) OF SAMUEL INSULL at 199 (1915). ("I think it was some twelve years ago that I first tried to voice the idea that our business is a natural monopoly and that we must accept, with that advantage, the obligation which naturally follows, namely, regulation").

5 *See* GREGORY MANKIW *supra* note 1 at 305; *See also, generally,* A. Michael Spence, *Monopoly, Quality, and Regulation*, 6 BELL J. ECON. 417 (1975).

6 Samuel Insull *supra* note 4.

7 For example, under the predominant form of regulation (cost-of-service regulation), electric power companies are fully compensated for their cost of production and thus have zero incentive to minimize their operating costs. This moral hazard can lead to wasted resources, inflated fuel and labor costs, and inefficient plant operations. *See*, Steve Cicala, *When Does Regulation Distort Costs? Lessons from Fuel Procurement in US Electricity Generation*, 105 AM. ECON. REV. 411 (2015); Kira R. Fabrizio et al., *Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency,* 97 AM. ECON. REV.1250 (2007). In addition, utilities typically earn profits in proportion to their capital investments. As a result, utility decision making has an inclination toward capital intensive solutions even if they are not the most efficient. *See*, *generally*, Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint,* 52 AM. ECON. REV. 1052-69 (1962).

8 *See, generally,* Erin T. Mansur & Matthew White, *Market Organization and Efficiency in Electricity Markets*, YALE SCHOOL OF MGMT. WORKING PAPER (2009); Steve Cicala, *Imperfect Markets Versus Imperfect Regulation in US Electricity Generation,* UNIVERSITY OF CHICAGO WORKING PAPER (2019) (showing market-based dispatch reduces cost and increases trade relative to bilateral arrangements.). *See also, generally*, Cicala *supra* note 7; Fabrizio et al., *supra* note 7. (Showing how regulated utilities don't minimize costs.).

9 *See* Severin Borenstein & James Bushnell, *The US Electricity Industry After 20 Years of Restructuring*, 7 ANN. REV. ECON. 437, 438 (2015). (Summarizing the restructuring of the electric power sector); Joskow, Paul L. "Restructuring, competition and regulatory reform in the US electricity sector." Journal of Economic Perspectives 11.3 (1997): 119-138. (Summarizing restructuring in the moment.); Paul Joskow and Richard Schmalense. MARKETS FOR POWER. 1983. (Identifying some of the benefits and costs of departing from the traditional organization of electric power.)

[10] *See* Borenstein & Bushnell *supra* note 9 at 438. ("The central premise of this article is that views of restructuring in the electricity industry over the past two decades have been driven primarily by … fluctuations in the relationship between the average cost and marginal cost of producing and delivering electricity to consumers.");

[11] The first major reform encouraging competition was the Public Utility Regulatory Policies Act of 1978 (PURPA), which encouraged competition from third parties. In the 1990s, several states legislatures and public service commissions began to directly decouple electricity generation from transmission and distribution, and encouraged, or mandated, electric utilities join or form a wholesale market. Of particular note at the Federal level, the Federal Energy Regulatory Commission promulgated Order 888 in 1996 requiring utilities to provide open access to their transmission infrastructure and Order 2000 in 1999 encouraging transmission utilities to join RTOs. Both of these Orders resulted from the Energy Policy Act of 1992. See FED. ENERGY REG. COMM'N, *supra* note 2 at 39. (Summarizing restructuring.)

[12] *See* Borenstein & Bushnell *supra* note 9 at 439-447. (Identifying these three implementations of restructuring.)

[13] *See* Borenstein & Bushnell *supra* note 9 at 439. ("There is clear evidence that competition has improved efficiency at power plants and improved the coordination of operations across a formerly balkanized power grid.") at 445 ("The creation and expansion of the RTO/ISO model may be the single most unambiguous success of the restructuring era in the United States . . . Although the early momentum for aggregating utility control areas into more regionally managed RTOs was provided by the belief that it was a necessary step toward the ultimate goal of deregulating generation and retail, the expansion of the RTO structure has come to be viewed as a valuable legacy of this period, even for states that never showed serious interest in these other aspects of restructuring.")

[14] *See* Joskow *supra* note 9 at 119-120. ("Potentially competitive segments (the generation of electricity) are being separated structurally or functionally from natural monopoly segments (the physical transmission and distribution of electricity). Prices for, entry to and exit from the competitive segments are being deregulated, and consumers are given the opportunity to choose among competing suppliers. Services provided by the natural monopoly segments are being unbundled from the supply of competitive services, nondiscriminatory access to "essential'' network facilities mandated and prices for use of these facilities determined by new regulation mechanisms that are designed to control costs better than traditional rate-of-return regulation procedures.")

[15] *See* Cramton, *Electricity Market Design*, 33 OXFORD REV. ECON. POLICY 4, 589-612, 591, (2017). ("In broadest terms, regulators seek a market design that provides reliable electricity at least cost to consumers.")

[16] *See, generally*, Jennifer Chen, *supra* note 3 at 9. (Discussing the operations of an RTO.).

[17] U.S. DEPT. OF ENERGY, *The Value of Economic Dispatch* (2005). (Defining economic dispatch, characterizing and quantifying the benefits it provides.); FED. ENERGY REG. COMM'N, *Security Constrained Economic Dispatch: Definition, Practices, Issues and Recommendations* (2006). (Summarizing SCED practices and identifying recommendations to improve SCED.); U.S. DEPT. OF ENERGY, *Economic Dispatch of Electric Generation Capacity* (2007). *See, also,* 155 FERC ¶ 61,276 ("Order 825") (requiring each RTO settle energy transactions in its real-time markets at the same time interval it dispatches energy.) Prior to Order 825, every RTO dispatched electricity generations in the real-time market every 5-minutes.

[18] *See, generally,* Cramton, *supra* note 15 at 597. (Describing a real-time energy market).

[19] *See*, Kate Konschnik, *Competition Case Study: The Southern Grids: 2000–2006,* Nicholas Institute for Environmental Policy Solutions (2019) at 2.

[20] *Id.* at 3.

[21] *Ibid.*

[22] PJM Value Proposition, https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ash (Accessed 08/20/2020); MISO Value Proposition Study, https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/ (accessed 08/20/2020).

[23] MISO *supra* note 22 (Showing costs are roughly 10%).

[24] *See* JAMES BUSHNELL, ERIN T. MANSUR & KEVIN NOVAN, REVIEW OF THE ECONOMICS LITERATURE ON US ELECTRICITY RESTRUCTURING 24 (2017), https://arefiles.ucdavis.edu/uploads/filer_public/e0/ee/e0eefda6-9fe2-4f88-8ca6-a00f25379754/restructuring_review.pdf

[25] *See* Cicala *supra* note 8 at 1.

[26] *See* Judy Chang, Johannes Pfeifenberger, & John Tsoukalis, *Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers*, Brattle Group, (2019) at 7.

[27] PJM *supra* note 22 (Showing "Energy Production Costs" as 20% of total benefits.); MISO *supra* note 22 (Showing "Dispatch of Energy" as 10% of total benefits.).

[28] PJM *supra* note 22 (Showing "Integrating More Efficient Resources" and "Generation Investment" both as an additional 30% of total benefits.); MISO *supra* note 22 (Showing "Footprint Diversity" as over 60% of MISO's total benefits, and "Improved Reliability" as an additional 10% of the benefits.).

[29] PJM *supra* note 22 (Showing annual 10 million tons of carbon emissions avoided due to reduced curtailment.); MISO *supra* note 22 (Showing "Wind Integration" as $415 to $477 million in annual benefits.).

[30] MISO *supra* note 22 (Showing "regulation" and "spinning reserves" as 2 to 3% of total benefits.)

[31] FED. ENERGY REG. COMM'N Regional Compliance Orders, https://www.ferc.gov/industries-data/electric/overview/order-no-1000-regional-compliance-orders

[32] E.g., MISO Transmission Expansion Plan (MTEP) process. https://www.misoenergy.org/planning/planning/.

[33] PJM *supra* note 22 (Showing "Reliability" as 10% of the benefits).

[34] *See* Tony Clark, Ray Gifford and Matt Larson, Utility Dive Opinion, It's Time for Emergent Markets to Take Center Stage in Non-RTO Regions of The Country, July 27, 2020. (Discussing how RTOs are "prescribed" markets.).

[35] *See* PJM History, https://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx.

[36] *See* W. M. Warwick, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Electricity Markets, Prepared for the US DOP Federal Energy Management Program, at 5.2 (2002).

[37] *See* FED. ENERGY REG. COMM'N *supra* note 2, at 38.

[38] *See* Jennifer Chen & Michael Bardee, *How Voluntary Electricity Trading Can Help Efficiency In The Southeast*, R Street Policy Study No. 201, 6, (2020). (Describing SPP WEISS in context of voluntary electricity trading); SPP, Western Energy Imbalance Service Market, https://www.spp.org/weis.

[39] SPP *supra* note 38 (Listing utility participants.).

[40] *See* California ISO, Western EIM Benefits Report Second Quarter 2020, at 3 (2020). https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ2-2020.pdf.

[41] *Id*., at 3, 18.

[42] *See* Robert Wilson, *Architecture of Power Markets*, 70 ECONOMETRICA 4, 1299-1340, 1303 (2002). (Identifying the difference between "integrated" and "exchange-based" (referred to as "unbundled") markets.).

[43] *See* Cramton *supra* note 15, at 608. (". . .in the late 1990s, the debate between market models was raging in the US.").

[44] In particular, there are non-convexities in the cost of electricity production due to startup costs and minimum/maximum production limits for each generator, transmission constraints, production externalities, the public good of frequency-regulation, redundant cost structures; all of which are happening nearly instantaneously in real-time.

[45] *See* Cramton *supra* note 15, at 610. ("I do believe that there are settings where the exchange model can work well . . . However, in most other settings, the integrated model has compelling advantages.")

[46] *See*, Cramton *supra* note 15 at 608. ("Today's integrated model simply does a better job of addressing and pricing the constraints via direct optimization. Efficient transmission pricing is a lead example. The exchange model operating in much of Europe is improving, but still falls short in pricing transmission congestion both within and across countries.").

[47] *See* Cramton *supra* note 15, at 608-610. (Generally discussing "Which market design is best?". For example, at 608, "The integrated model, however, better handles non-convexities and is simpler for participants.").

[48] *See* Cramton, *supra* note 15 at 590; FED. ENERGY REG. COMM'N, *Working Paper on Standardized Transmission Service and Wholesale Electric Market Design* (2002).

[49] Southern Company, Southern Wholesale Energy, https://www.southerncompany.com/about-us/our-business/southern-wholesale-energy.html (accessed 08/30/2020).

[50] John Downey, *Duke Energy, Southern Co. and others in talks to establish a Southeast energy market*, Carolina Business Journal, July 14, 2020; Maggie Shober, Potential Energy Market in the Southeast? What We Know So Far About SEEM. https://cleanenergy.org/blog/potential-energy-market-in-the-southeast-what-we-know-so-far-about-seem/.

[51] For example, if demand for electricity is expected to be 300 MW, the utility submits a base schedule showing how it can generate the 300 MW or purchase it from another utility to match forecasted demand.

[52] Economic bids are typically price-quantity pairs outlining the electricity generator's supply function. It can include other information such as the minimum and maximum it can produce economically (or in emergencies).

[53] In Western EIM, resource sufficiency tests include a balance test, a bid capacity test, a flexible ramping sufficiency test, and a feasibility test. See, Bonneville Power Administration, EIM 101 Workshop Presentation, 59, (2018). https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20180913-September-13-2018-EIM-101-Workshop.pdf.

[54] If a utility under rate of return regulation does not enjoy the benefit of an EIM, because cost savings are passed on to ratepayers, they are less likely to participate in a voluntary EIM. State regulators can play an important role in requiring the utility to participate in the EIM and ensuring the production cost savings are passed on to ratepayers.

[55] *See* Chen & Bardee, *supra* note 38 at 7-8. (Discussing regulatory approval and governance, and a standalone EIM.)

[56] *See* Chen *supra* note 3 at 16 (Describing an Energy Imbalance Market or Service.)

[57] Western Energy Imbalance Market, Join EIM, https://www.westerneim.com/Pages/JoinEIM.aspx..

[58] For example, Western Energy Imbalance Market, Energy Imbalance Market – benefit assessments: https://www.westerneim.com/Pages/documentsbygroup.aspx?GroupID=7DF86332-C71D-44B7-836B-56181A694C8C. (A catalog of the benefit-cost analysis done by the Western EIM's current members prior to joining the Western EIM.)

[59] *Id. See, specifically,* Puget Sound Energy, Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market at 2, https://www.westerneim.com/Documents/PugetSound-ISO_EnergyImbalanceMarket-BenefitsAnalysis.pdf. ("These startup costs, … ongoing costs and annual benefits … would produce a Net Present Value (NPV) of $153.7 million to $174.4 million.")

[60] For example, the current tariff for the Western EIM is filed by CAISO. See, California Independent System Operator Corporation Fifth Replacement Electronic Tariff, Section 29, August 1, 2019: http://www.caiso.com/Documents/Section29-EnergyImbalanceMarket-asof-Aug1-2019.pdf

[61] *See*, Bonneville Power Administration, *supra* note 53 at 26.

[62] *See* FED. ENERGY REG. COMM'N *supra* note 2 at 61. ("Volumes for short-term transactions can be low, particularly under normal weather conditions. . . The Southeast has relatively low volumes of short-term trades compared to the Western regions . . [there is a] relatively small market for short-term transactions.")

[63] *See* FED. ENERGY REG. COMM'N *supra* note 2 at 61.

[64] *See* FED. ENERGY REG. COMM'N *supra* note 2 at 61.

[65] *See* State of North Carolina Utilities Commission, "Order Approving Merger Subject to Regulatory Conditions and Code of Conduct," In the Matter of Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct, Docket Nos. E-2, SUB 998, E-7, SUB 986, pp. 29. https://dms.psc.sc.gov/Attachments/Matter/0db7d38b-155d-141f-2376ec5bc8152322 ("According to the Compass Lexecon Study, total system savings over five years attributable to joint dispatch, using base case assumptions, are expected to be as follows: 2012 – $38 million; 2013 – $49 million; 2014 – $64 million; 2015 – $97 million; and 2016 – $116 million.")

[66] *See* Monitoring Analytics, *Quarterly State of the Market Report for PJM: January through March*, 397, (2018). http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q1-som-pjm-sec9.pdf

[67] *Id.*

[68] *Id.* at 403. VACAR South Includes: Duke Energy Carolinas, LLC (DUK), Duke Energy Progress (DEP), South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)

[69] Southern Company Auction Clearing Prices are available here, https://www.southerncompany.com/about-us/energy-auction/auction-clearing-prices.html.

[70] *See* Azevedo. See, Thomas A. Deetjen & Inês L. Azevedo " Reduced-Order Dispatch Model for Simulating Marginal Emissions Factors for the United States Power Sector." 53 Environmental Science & Technology 17, 10506-10513, (2019). https://doi.org/10.1021/acs.est.9b02500.

[71] *See* Chang et al., *supra* note 26 at 7. (Showing Duke Energy's operating cost of over $2 billion in 2017.)

[72] *See* Chang et al., *supra* note 26 at 7. ("Based on this high-level analysis, we estimate that production cost savings from Duke joining PJM could be as high as 9% to 11%").

[73] *See* PacifiCorp-ISO Energy Imbalance Market Benefits at 14, https://www.westerneim.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf. ("For a PacifiCorp-ISO EIM, ISO estimates that PacifiCorp would incur a one-time fixed charge of approximately $2.1 million and $1.35 million per year in administrative charges"); Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market at 2, https://www.westerneim.com/Documents/PugetSound-ISO_EnergyImbalanceMarket-BenefitsAnalysis.pdf. ("PSE staff has estimated that PSE would incur one-time EIM startup costs of $14.2 million including contingency costs, and ongoing costs of approximately $3.5 million per year.")

[74] *See* Reiko Matsuda-Dunn, Michael Emmanuel, Erol Chartan, Bri-Mathias Hodge, and Gregory Brinkman. 2020 at *vi*. Carbon-Free Resource Integration Study. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5D00-74337. https://www.nrel.gov/docs/fy20osti/74337.pdf.

[75] *Id.*

[76] *See* GE ENERGY, WESTERN WIND AND SOLAR INTEGRATION STUDY 311 (2010) (prepared for National Renewable Energy Laboratory). *See also* PAUL DENHOLM & ROBERT MARGOLIS, NAT'L RENEWABLE ENERGY LAB., ENERGY STORAGE REQUIREMENTS FOR ACHIEVING 50% SOLAR PHOTOVOLTAIC ENERGY PENETRATION IN CALIFORNIA 12 (2016), https://www.nrel.gov/docs/fy16osti/66595.pdf.

[77] *See* GE ENERGY, *supra* note 76 at 83.

[78] To the extent that the cost of balancing reserves are borne by third-party suppliers of renewable energy, as is now the case in the Carolinas, they unnecessarily penalize, and potentially inhibit, the development of renewable resources.

[79] *See* Matsuda-Dunn et al., *supra* note 74.

[80] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC CPRE RFP Tranche 2, at 16, Oct. 2019, https://dms.psc.sc.gov/Attachments/Matter/327ceaca-88d7-454a-8f87-801b620897f6 ("DEP/DEC has the right to curtail energy from the Facility up to 10% of the Facility's annual energy production in the DEP jurisdiction and 5% in the DEC jurisdiction, without compensation to the Facility owner.")

[81] *See* Federal Energy Regulatory Commission staff paper, *Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market*, at 1 (2013).

[82] *Id.*, at 4, 8

[83] In application, an EIM might place limits on how much a Balancing Authority can "lean-on" the EIM to balance supply and demand. This is to prevent the free-riding problem inherent with public goods, which in this case includes the service of providing excess reserves. This is the case in the Western EIM. *See* Bonneville Power Authority *supra* note 53.

[84] *See* Environmental Defense Fund, Managing the Transition, Practice Solutions for Stranded Gas Asset Risk in California: https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf

[85] *See, for example,* Public Service Commission of South Carolina Order NO. 2019-881, at 31.

[86] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments, NCUC Docket No. E-100, Sub 158, at pp. 92-94.

[87] *See* Direct Testimony of R. Thomas Beach, On Behalf of NCSEA, NCUC Docket No. E-100, Sub 158, 17.

[88] *See* Federal Energy Regulatory Commission staff paper, Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market (2013), at 18.

[89] *Id.*

[90] *See* California ISO, *supra* note 40, Table 9 at 21.

[91] *See* Gimon et al., *supra* note 3

[92] *See* Gimon et al., *supra* note 3. *See also,* Energy Innovation, Southeast U.S. Wholesale Electricity Market/RTO Online Data Explorer, https://energyinnovation.org/2020/08/25/southeast-wholesale-electricity-market-rto-online-data-explorer/ (accessed 9/6/2020).

[93] *See* Energy Innovation *supra* note 92. (Displaying the total resource costs in North Carolina for 2025. IRP (status quo) scenario reports total resource costs of approximately $13.6 billion. Economic IRP (including competitive capacity procurement) scenario reports total resource costs of approximately $12 billion. RTO scenario (including competitive capacity procurement, optimized dispatch, capacity planning, and distributed resource optimization) scenario reports total resource costs of approximately $11.2 billion.)

[94] *See, e.g.*, Sonal Patel, Power Magazine, The Significance of FERC's Recent PJM MOPR Order Explained, https://www.powermag.com/the-significance-of-fercs-recent-pjm-mopr-order-explained/; *See also, e.g.*, Robert Walton, Utility Dive, New Jersey looks to exit PJM capacity market, worried MOPR will impede 100% carbon-free goals, March 31 2020.

[95] *See, e.g.*, Jeff St. John, *FERC Decisions Could Undermine Renewables and Energy Storage in New York Capacity Markets,* Greentech Media, February 21, 2020.

[96] *See* Chen & Bardee *supra* note 38 at 10.

[97] *See*, Cramton *supra* note 15 at 608. ("Today's integrated model simply does a better job of addressing and pricing the constraints via direct optimization. Efficient transmission pricing is a lead example.")

[98] Southern Company System Intercompany Interchange Contract (2007) at 23.

[99] *Supra* **Table 4** for a description of SEEM's footprint.

[100] State of North Carolina Utilities Commission *supra* note 65; Gimon et al., *supra* note 3.

[101] *See* Chen & Bardee, *supra* note 38 at 9. *See supra* note 73 for costs of an EIM.

[102] *See* John Downey, *supra* note 50. (Quoting Duke staff.).

[103] Energy Imbalance Memorandum of Understanding, https://www.westerneim.com/Documents/ISO-PacifiCorpMOU_Effective20130212.pdf

[104] *See*, Cramton *supra* note 15 at 593. (Describing a successful market design.)

[105] *See*, Cramton *supra* note 15 at 608. ("Today's integrated model simply does a better job of addressing and pricing the constraints via direct optimization. Efficient transmission pricing is a lead example. The exchange model operating in much of Europe is improving, but still falls short in pricing transmission congestion both within and across countries.")

[106] *See*, Cramton *supra* note 15 at 608. ("The integrated model, however, better handles non-convexities and is simpler for participants.")

[107] *See*, Cramton *supra* note 15 at 608. ("The integrated model provides opportunities and protections for the smaller generators that may be missing in the exchange model. . . The integrated model also supports competition through transparency")

[108] *See* FERC *supra* note 17.

[109] *See*, IRENA, Innovation Landscape Brief: Increasing Time Granularity on Electricity Markets, International Renewable Energy Agency, Abu Dhabi, (2019) at 8.

[110] *See*, IRENA, Innovation Landscape Brief: Increasing Space Granularity in Electricity Markets, International Renewable Energy Agency, Abu Dhabi, (2019) at 7.

[111] *See*, *e.g.*, Paul Brehm & Yiyuan Zhang, The Efficiency and Environmental Impacts of Market Organization: Evidence from the Texas Electricity Market, Working Paper (2019), https://www2.oberlin.edu/faculty/pbrehm/BrehmZhang_Electricity_Mkt_Structure.pdf.

[112] *See*, Eric Gimon et al., *supra* note 3 at 13. (Showing 46% reduction in carbon dioxide emissions by 2040.)

[113] *See*, COMMENTS OF THE INSTITUTE FOR POLICY INTEGRITY BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO, Proceeding No. 19M-0495E, at 12.

[114] *See*, MATT BUTNER ET AL., CARBON PRICING IN WHOLESALE ELECTRICITY MARKETS: AN ECONOMIC AND LEGAL GUIDE 14 (2020), https://policyintegrity.org/publications/detail/carbon-pricing-in-wholesale-electricity-markets.

[115] Deetjen & Azevedo *supra* note 70. The entirety of the model's code, written in python, can be found at https://github.com/tdeetjen/simple_dispatch.

[116] In this setting "large" means >25 MW capacity. The model only includes these electricity generators because only their hourly production is publicly available through EPA's Continuous Emissions Monitoring System.

[117] Figure S5 in Thomas A. Deetjen & Inês L. Azevedo. "Supporting Information: A reduced-order dispatch model for simulating marginal emissions factors for the U.S. power sector." https://pubs.acs.org/doi/suppl/10.1021/acs.est.9b02500/suppl_file/es9b02500_si_001.pdf

[118]EPA Power Sector Modeling Platform v6 using IPM , Table 3-21 Annual Transmission Capabilities of U.S, https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-november-2018-reference-case

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