Who's Ready to Trade? The Welfare Implications of Voluntary Emissions Trading Within Regional Electricity Markets

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1 Introduction

Although the costs of comprehensive federal climate legislation, such as a federal cap and trade system, have been shown to be quite small (CBO, 2009), such policies have so far failed to materialize in the United States. Cap and trade systems are thought to provide a cost-effective method to reduce greenhouse gas (GHG) emissions as they allow affected economic agents (e.g., electricity generating units or EGUs) with high marginal costs of reducing GHG emissions to purchase abatement through permit markets from agents with lower marginal costs (Hahn and Stavins, 2011).

Traditionally, all economic agents covered under a federal emissions cap would be allowed to participate in a common permit market. However, the Obama Administration U.S. Environmental Protection Agency (EPA) issued the Clean Power Plan (CPP) in 2015 which assigned emissions targets to individual states with a goal to reduce GHG emissions from EGUs by 32% in 2030, relative to 2005 levels. Unique to the CPP, state governments can voluntarily choose to opt-in to allow their EGUs choose to participate in a inter-state permit market by choosing to submit a "trade-ready" implementation plan. If all states were to opt-in, states would have effectively voluntarily established a cap-and-trade system that includes all EGUs within the U.S. at near zero coordination cost. Whether states will voluntarily opt-in to such a permit trading system is unclear. Individual states may benefit more from not opting in, but traditional economic theory suggests that this may raise compliance costs nationally.

In this paper I answer two research questions. First, when will state adoption of trade-ready plans be Pareto superior to the adoption of non-trade-ready plans? That is, when will the adoption of a trade-ready plan lead to greater direct costs

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(i.e., aggregate surplus excluding external benefits) for some states while not lower direct costs for others? Second, when will the adoption of trade ready plans by all states increase total direct costs nationally?

To answer these questions, I develop a static, multi-state analytic and numerical model which captures electricity generation, capacity, and emissions trading across a restructured wholesale regional (inter-state) electricity system, to evaluate when states are likely to voluntarily opt-in to inter-state allowance trading. The analytic model consists of two nodes, spanning two states with a node in each state and a transmission line of fixed capacity connecting them where electricity can be freely traded between them. States can exhibit heterogeneity in generation costs, marginal emissions intensity of generation, demand levels, and assigned emissions caps. When both states select a trade-ready plan, emissions allowances are traded within a single permit market. When either or both states opt-out of a trade-ready plan, then each state is forced to comply with their assigned emissions caps using individual state-only permit markets. I derive simple analytic formulas that decompose the change in state and national (i.e. both states) direct costs (henceforth, welfare) from moving between these two permit market configurations. I find that the decision to adopt a trade-ready plan or not has important distributional implications which reflect equilibrium changes in both electricity and emissions markets, conditional on transmission constraints across the wholesale market. This implies that states may have incentives to not adopt trading. I next perform a numerical analysis that identifies the key channels that drive welfare changes in light of my research questions. My numerical model is comprised of a five node network with restricted transmission flows, which is constructed, calibrated, and validated to approximate the regional wholesale electricity system dispatched by PJM. I allow new new gas, wind, and solar capacity to be added to each node and capture welfare interactions of the CPP with state's pre-existing Renewable Portfolio Standards (RPS) and other critical federal environmental regulations. The results of my numerical model are consistent with those identified by the analytic model in terms of the welfare impacts from adopting a trade-ready plan; that is, the adoption of a trade-ready plan improves total welfare, but given states' initial emission cap assignments, some states may decline to opt into a trade-ready plan. Additionally, the numerical results also show that interactions between state RPS's and the CPP can result in emissions leakage arising from additional natural gas capacity expansion, which offsets the mitigation intended by the CPP.

Although the CPP was repealed under the Trump Administration and this repeal is still under judicial review, the analysis we conduct in this paper provides valuable insights regarding the ability for restructured regional wholesale electricity markets to efficiently regulate GHG emissions in light of the fact that the authority to regulate GHG emissions lies with state governments and not the Regional Transmission Organization (RTO). For example, PJM is currently discussing incorporating carbon pricing in power dispatch decisions. However, under current federal rules PJM lacks the regulatory authority to initiate such a policy regime on their own. Instead, it appears that the only path forward would be for states to voluntarily agree to such a carbon pricing regime collectively. My analysis provides the analytic and numerical framework that can be used to evaluate whether and under what conditions this is likely to occur. Moreover, about half of the states within PJM currently use RPS to incentivize renewable generation. Our analysis provides useful insights regarding when states are likely to adopt or not adopt interstate trading in Renewable Energy Credits (RECs) and the overall implications for the cost-effectiveness of this state-driven, piecemeal regulatory approach for wholesale electricity markets.

The rest of this paper proceeds as follows. In Section 2, I review the policy and in Section 3 the extant literature in this area. In section 4, I detail and discuss the analytic model and its theoretical results. In Section 5, I discuss the results from my numerical model and in Section 6 the conclusion.

2 Policy Overview

The Clean Power Plan (CPP) was issued by the EPA in August 2015 to reduce GHG emissions from fossil fuel EGUs. The CPP allows states to choose to comply with a Mass-based (MB) standard or a Rate-based (RB) standard. A MB standard effectively caps emissions for EGUs within each state (in tons of CO_2) whereas a RB standard would entail that EGUs within each state achieve an average emissions intensity target for generation from all EGUs within a year (in lbs CO_2 per MWh).

In addition to the choice of standards, each state can choose to submit an implementation plan that decide to opt in inter-state 'trade-ready' or not.[1] If two or more states adopt a trade-ready plan with a MB standard, the EGUs within those states can freely trade allowances (measured in tons) such that total emissions across all states equals a cap that is the sum of all states' MB standards. Likewise, a similar approach is possible for states that adopt RB compliance.[2] Interstate trading is not

[1]If states do not opt in to submit a trade-ready plan, then EGUs within the state may still trade allowances with one another in their state permit market.

[2]In actuality the regulation is considerably more complex. Under a MB compliance pathway, states can choose to adopt a mass target that only covers existing EGUs or a larger mass target that covers both existing and new EGUs. Likewise, under RB compliance, states can choose from one of three approaches, only one of which can be made trade-ready. First, states can choose to comply to two separate RB standards that are uniform nationally with respect to two unit classes: fossil-fuel steam (FFS) and natural-gas (NG) fired EGUs. Only this approach can be made trade-ready. Under interstate trade-ready compliance, the annual average annual average emissions intensity by units within each class and must be less than or equal to the respective unit class standard, across all of those states that adopted trade-ready RB plans. Under non-trade ready compliance, the annual average annual average emissions intensity by units within each class and must be less than or equal to the respective unit class standard within each state. Second, states have also been assigned distinct state RB standard which is a weighted average of the two national standards by unit class, weighted by the state's 2012 mix of FFS and NG generation, and which cannot be made trade-ready. If a state complies with a state RB standard, then the annual average emissions intensity of all units in the state must be equal to or below the RB standard assigned to the state. Finally, states can

allowed between states that adopt different compliance pathways. That is, a state that adopts a trade-ready plan using a MB standard cannot sell allowances or ERCs to a state that adopts a trade-ready plan using a RB standard.

3 Literature Review

This paper contributes to two literatures. First, it contributes to the literature studying the impacts of the proposed Clean Power Plan (CPP) on electricity markets.[3] Several papers have analyzed the cost effectiveness of the proposed rule both quantitatively and qualitatively. A well-known criticism of rate-based standards is that they implicitly subsidize emissions from cleaner generation units and thus may not reduce total emissions (Holland et al., 2009; Hogan, 2015; Fowlie et al., 2014). Mass-based standards are likely to be more cost effective since they impose an implicit tax on GHG emissions from both clean and dirty generation units in proportion to those units' emission intensities (Burtraw et al., 2015). Bushnell et al. (2017) evaluates the incentives for complying with mass or rate-based compliance pathways under the proposed rule. To do so they develop an electricity model spanning several states in which abatement is only possible from altering the generation mix from dirtier fossil fuel steam units to cleaner natural gas units. They show that when demand is perfectly inelastic, cost-effectiveness can be achieved under both MB and RB compliance. However, when demand is elastic, cost-effectiveness can only be achieved under MB compliance. They also find that, while total compliance costs may be lower under a cooperative MB compliance strategy, individual states may have greater welfare from adopting other strategies. Bielen et al. (2017) examines the implications of interstate trading on compliance costs and emissions outcomes from RB and MB compliance under the proposed rule. Their analysis assumes perfectly inelastic demand, ignores transmission constraints, and assumes that states have identical emissions intensities of electricity generation. Like Bushnell et al. (2017), their analysis also exclusively focuses on abatement from changes in the composition of generation existing EGUs. For a very narrow range of heterogeneous cap assignments, they find that both states gain from cooperating under a multi-state MB compliance pathway when permits are allocated based upon assigned caps.

Second, my paper also contributes to a sizable literature that considers the welfare and emissions implications of cap-and-trade systems. Hahn and Stavins (2011)

also comply with custom emission intensity targets that cover individual units or units of particular custom classes such that the cumulative effect of these targets satisfies the state RB standard, and thus also cannot be made inter-state trade ready.

[3]Under the proposed rule, states were not provided the ability to submit a trade-ready implementation plan. However, under both the proposed and final rule, states are able to coordinate and submit single multi-state plans (i.e. comply cooperatively). Given that the trade ready option under the final rule effectively achieves the benefits of multi-state compliance without costly negotiation, we suspect likely to be more popular among states than multi-state compliance and thus do not consider this pathway here.

examine the conditions under which cap-and-trade systems might fail to be cost effective, such as the existence of market power in allowance markets or non-cost-minimizing behavior by firms. Sauma (2012) evaluates the conditions in electricity markets in which incomplete cap-and-trade systems are likely to generate emissions leakage[4]; that is, when various regulatory entities impose caps of varying relative stringency (including possibly no cap at all) on the EGUs within their domain and this leads to possibly unintended increases in emissions (positive leakage) or decreases in emissions (negative leakage) not anticipated by the caps as a result of the change in the equilibrium flow of electricity within an interconnected electricity market. Using a simple two node network, Sauma (2012) shows that if a transmission constraint is binding before one of the two states unilaterally imposes a cap on their own EGUs, and the covered state imports electricity from the uncovered state than there will be no leakage. If this is not the case, then positive leakage can result. Limpaitoon et al. (2011) considers the implications of transmission constraints on a cap and trade system spanning the electricity sector when market power may be present. They find that a cap-and-trade system without transmission constraints will yield an increase in aggregate surplus in the perfectly competitive market. They also show that transmission constraints may increase producer surplus relative to the transmission unconstrained case. Relatedly, Downward (2010) considers the impacts of transmission constraints on the welfare implications of a carbon tax. They find that a carbon tax can lead to an increase in total emissions when a transmission constraint is binding.

4 Analytic Model

The analytic model comprises two nodes, $i = 1, 2$, spanning two states with a node in each state and a transmission line of fixed capacity, $\bar{f}$, that connects them.[5] Initially, there are two existing EGUs in each node, a clean (e.g., renewable) EGU which release GHG emissions at rate ϕ_i^{er} and a dirty (e.g., fossil fuels) EGU which releases GHG emissions at rate ϕ_i^{ef}, such that $\phi_i^{ef} > \phi_i^{er} \geq 0$. The model also allows

[4]See Fowlie (2009), Goulder et al. (2012) and Bento et al. (2015) for additional discussion of these concepts. Baylis et al. (2014) reviews the conditions when negative leakage is likely to occur.

[5]I model electricity market dispatch as the solution to a decentralized competitive equilibrium in which electricity producers in each state are constrained by the amount of electricity they can export to another state. A more conventional formulation is to specify centralized dispatch as the solution to an optimal power flow (OPF) problem in which a central operator chooses supply, demand, and flows to maximize the sum of producer and consumer surpluses of all electricity producers and consumers within its control area, subject to the physical constraints of the electric network, where the transmission network is characterized by direct current (DC) load flow (Gabriel et al., 2013). For my two node network the two solutions are equivalent by the First Fundamental Welfare Theorem (see, e.g., Debreu (1959), and references therein), given our model assumptions and the observation that the solution to the DC OPF is simply the solution to the social planner's problem. This equivalence is possible because our two node network formulation only accounts for transmission constraints reflecting Kirchhoff's Current Law and does not capture network externalities attributable to Kirchhoff's Voltage Law.

for the endogenous addition of new clean and dirty EGUs in each node which release GHG emissions at rates ϕ_i^{nr} and ϕ_i^{nf}, respectively, such that $\phi_i^{nf} > \phi_i^{nr} \geq 0$, $\phi_i^{ef} \geq \phi_i^{nf}$, and $\phi_i^{er} \geq \phi_i^{nr}$. Each state also has a pre-existing own Renewable Portfolio Standards (RPS), $\bar{r}_i \geq 0$, which specifies the minimum fraction of a state's total power generation that must come from clean EGUs (existing or new).[6] There are four goods in the economy: electricity supplied from existing and new EGUs of both types, a non-emissions generating numeraire good which reflects all other consumption in the economy, labor for which each state receives a fixed endowment, L_i, and permits. Electricity, the numeraire, and labor are assumed to be freely traded between states, although, because of the presence of a transmission constraint between the two states, trade in electricity may be constrained. Individual, state-level permit markets are present under intra-state permit trading, which emerges when either or both states decide not to adopt a trade-ready plan. When both states adopt trade ready plans, there is instead a single permit market spanning both states and thus inter-state permit trading occurs.

4.1 Consumer Demand

A representative consumer located in each state i consumes electricity and a numeraire good with preferences for these goods given by:[7]

$$U_i = u_i(x_i) + y_i, \tag{1}$$

where $u_i' > 0$ and $u_i'' < 0$. I assume that the numeraire, y_i, is linearly produced from labor, whose prices are normalized to one. In addition, I assume the agent receives all profits from the production of electricity in their state, π_i, the total value of permits allocated to the state under the CPP,[8] The total value of permits given the state's assigned MB standard equals the permit price realized in the relevant permit market, λ_i, multiplied by the MB standard assigned to the state under the CPP, $\bar{e}_i$. Consequently, the agent's budget constraint in these two cases is given by:

$$p_i x_i + y_i = L_i + \pi_i + \lambda_i \bar{e}_i \tag{2}$$

where λ_i is the permit price in each state i in each state i and p_i is the state price of electricity. If intra-state permit trading occurs then λ_i will vary across states, and a state's total demand for permits must equal the amount they are allocated under the CPP. However, if inter-state permit trading occurs then there is only one permit price across both states, $\lambda_1 = \lambda_2 = \lambda$, and one state may be a net buyer of permits and the other a net seller. Thus a change from one trading regime to the other will both alter the equilibrium permit price as well as the net amount of permits held by the state.

[6]When $\bar{r}_i = 0$, it is as if the state has no RPS.

[7]In what follows, I denote demand by lower-case letters and supply by upper case letters.

[8]Since the numeraire is linearly produced from labor under constant returns to scale, the profits from producing the numeraire are zero.

The consumer in each state maximizes (1) subject to (2), which yields the following Walrasian demand system:

$$x_i(\mathbf{p}, \boldsymbol{\lambda}) \text{ and } y_i(\mathbf{p}, \boldsymbol{\lambda}) \tag{3}$$

We also obtain the value function to the utility maximization problem, or indirect utility function, $V_i(\mathbf{p}, \boldsymbol{\lambda})$. Since each representative consumer receives all profits from production by economic agents within their state, normalization of indirect utility by the marginal utility of income, μ_i, provides a complete measure of state aggregate surplus (simply state welfare in what follows).

4.2 Electricity Production

I consider the supply of electricity from four possible EGUs in each state, denoted by the superscript $j \in \{ef, er, nf, nr\}$.

Electricity Production from Existing EGUs Each state i has a representative producer of dirty electricity (from fossil fuel EGU), X_i^{ef}, and a representative producer of clean electricity (from renewable EGU), X_i^{er}. The total amount of electricity supplied by existing EGUs in each state equals: $\sum_b X_i^b = X_i^{er} + X_i^{ef}$. Electricity for each existing EGU type $b \in \{ef, er\}$ is produced from labor according to the following decreasing returns to scale production function:

$$l_i^b = g_i^b\left(X_i^b\right), \quad \forall b = \{ef, er\} \tag{4}$$

where $g_i^{b'} > 0$ and $g_i^{b''} > 0$.

Electricity production from existing EGUs is assumed to generate CO_2 emissions in each state according to:

$$\sum_b e_i^b = \sum_b \phi_i^b X_i^b, \tag{5}$$

where $\sum_b e_i^b$ is CO_2 emission from existing EGUs in state i, $\phi_i^b > 0$ is the amount of CO_2 generated per MWh of electricity supplied or emissions intensity of electricity generation for existing EGU type b in state i. We assume that $0 \leq \phi_i^{er} < \phi_i^{ef}$.

Electricity Production from New EGUs Each state i has an option to add a new dirty (fossil fuel) EGU, which produces dirty electricity, X_i^{nf} and a new clean (renewable) EGU, which produces clean electricity, X_i^{nr}. The total amount of electricity supplied by new EGUs in each state equals: $\sum_c X_i^c = X_i^{nr} + X_i^{nf}$. Electricity for each new EGU type $c \in \{nf, nr\}$ is produced from labor according to the following decreasing returns to scale production function such that:

$$l_i^c = g_i^c\left(X_i^c\right), \quad \forall c = \{nf, nr\} \tag{6}$$

where $g_i^{c'} > 0$ and $g_i^{c''} > 0$.

Electricity production from new EGUs is assumed to generate CO_2 emissions in each state according to:

$$\sum_b e_i^c = \sum_c \phi_i^c X_i^c, \tag{7}$$

where $\sum_c e_i^c$ is CO_2 emission from new EGUs in state i, $\phi_i^c > 0$ is the amount of CO_2 emissions generated per MWh of electricity supplied or emissions intensity of electricity generation for new EGU type c in state i. We assume that $0 \leq \phi_i^{nr} < \phi_i^{nf}$ and $0 \leq \phi_i^{nf} < \phi_i^{ef}$.

Clean electricity from the these new EGUs, X_i^{nr}, can be used to comply with the states' RPS targets but emissions from dirty electricity from these new EGUs, e_i^{nf} are not affected under the CPP.

The total amount of CO_2 emissions in each state i, therefore, is defined as:

$$e_i = \sum_j e_i^j = \sum_b e_i^b + \sum_c e_i^c, \quad \forall j = \{er, ef, nr, nf\} \tag{8}$$

Transmission Constraint The net flow of electricity is limited by the transmission constraint on the line and thus must satisfy:

$$-\bar{f} \leq f_{ii'} \leq \bar{f}. \tag{9}$$

where $f_{ii'} \gtreqless 0$ is the amount of electricity exported (>) or imported (<) from node i to node i'.

Environmental Policy Constraints The amount of clean generation and dirty generation in each state have to satisfy the RPS constraint:

$$\frac{X_i^{er} + X_i^{nr}}{X_i^{er} + X_i^{ef} + X_i^{nr} + X_i^{nf}} \geq \bar{r}_i \tag{10}$$

In addition, the amount of permits, $n_i \gtreqless 0$ demanded/supplied in state i must satisfy:

$$\sum_b \phi_i^b X_i^b \leq n_i \tag{11}$$

Producer profit in each state is given by:

$$p_i \left(\sum_j X_i^j - f_{ii'} \right) + p_{i'} f_{ii'} - \lambda_i n_i - \sum_j g_i^j \left(X_i^j \right) \tag{12}$$

in which $p_{i'}$ is marginal price of electricity in state i', p_i is the marginal price in state i, $\lambda_i n_i$ is the total value of permits.

The electricity producer in each state maximizes (12) subject to (9), (10), and (11), by choosing $X_i^j \geq 0$, $f_{ii'} \gtreqless 0$, and $n_i \gtreqless 0$. The result is total profits, electricity supplies from both existing and new units, flow demanded/supplied, permits demanded/supplied, and labor demanded by electricity producers:

$$\pi_i(\mathbf{p}, \boldsymbol{\lambda}), X_i^j(\mathbf{p}, \boldsymbol{\lambda}), f_{ii'}(\mathbf{p}, \boldsymbol{\lambda}), l_i^j(\mathbf{p}, \boldsymbol{\lambda}) \text{ and } n_i(\mathbf{p}, \boldsymbol{\lambda}) \tag{13}$$

4.3 Characterization of the Economic Equilibrium

A *competitive equilibrium under* intra-*state permit trading* in the model is the price vector $(\mathbf{p}, \boldsymbol{\lambda})$, such that:

$$\begin{aligned}
&\sum_i L_i = \sum_i \left(\sum_j l_i^j(\mathbf{p}, \boldsymbol{\lambda}) + y_i(\mathbf{p}, \boldsymbol{\lambda}) \right), \\
&\sum_i \sum_j X_i^j(\mathbf{p}, \boldsymbol{\lambda}) = \sum_i x_i(\mathbf{p}, \boldsymbol{\lambda}), \\
&f_{ii'}(\mathbf{p}, \boldsymbol{\lambda}) = -f_{i'i}(\mathbf{p}, \boldsymbol{\lambda}), \\
&n_i(\mathbf{p}, \boldsymbol{\lambda}) \leq \bar{e}_i, \forall i = 1, 2.
\end{aligned} \tag{14}$$

A *competitive equilibrium under* inter-*state permit trading* in the model is the price vector $(\mathbf{p}, \boldsymbol{\lambda})$, such that:

$$\begin{aligned}
&\sum_i L_i = \sum_i \left(\sum_j l_i^j(\mathbf{p}, \boldsymbol{\lambda}) + y_i(\mathbf{p}, \boldsymbol{\lambda}) \right), \\
&\sum_i \sum_j X_i^j(\mathbf{p}, \boldsymbol{\lambda}) = \sum_i x_i(\mathbf{p}, \boldsymbol{\lambda}), \\
&f_{ii'}(\mathbf{p}, \boldsymbol{\lambda}) = -f_{i'i}(\mathbf{p}, \boldsymbol{\lambda}), \\
&\sum_i n_i(\mathbf{p}, \boldsymbol{\lambda}) \leq \sum_i \bar{e}_i.
\end{aligned} \tag{15}$$

4.4 The Welfare Effects of Adopting Permit Trading

Given the analytic model, the marginal change in aggregate surplus in each state from adopting inter-state permit trading relative to intra-state trading can be decomposed as follows:[9]

$$dW_i = \left(\frac{1}{\mu_i} dV_i \right) = \underbrace{f_{ii'} dp_{i'}}_{dW_i^x} + \underbrace{(-1)(e_i - \bar{e}_i) d\lambda_i}_{dW_i^e} \tag{16}$$

[9]See Appendix 1 for all derivations. Here I consider a marginal change, and hence for a small enough marginal change, transmission is either binding before and after the marginal change or is not binding or not present before and after the marginal change. However, in my numerical analysis I report changes in aggregate surplus when it is possible for transmission to be binding or not binding before or after either trading regime.

where $f_{ii'} = (X_i - x_i) = -(X_{i'} - x_{i'})$. When there is no transmission constraint in the system or when the transmission constraint is not binding, $dp_{i'} = dp_i = dp$, $p_{i'} = p_i = p$ and $\|f_{ii'}\| \leq \bar{f}$, where dp_i is the change in electricity price in state i from allowing inter-state permit trading. If the transmission constraint is present and binding then $dp_i \neq dp_{i'}$ and $f_{ii'} = \bar{f}$ or $f_{ii'} = -\bar{f}$. The general formula for change in welfare for any state i is made up of two terms.

The first term in (16), dW_i^x, is the *electricity market term of trade effect (EME)* in state i. This equals net exports from state i to state i', $f_{ii'}$, multiply by the change in the market price of electricity in state i', $dp_{i'}$. As we show in the Appendix, the change in electricity price $dp_{i'}$ from switching to inter-state permit trading when emission caps are jointly binding under intra-state permit trading depends on permit prices, emission intensities, and RPS targets, $dp_{i'} = \dfrac{\dfrac{\phi_1}{g_1^{ef''}} + \phi_2 \dfrac{\lambda_2}{\lambda_1} + \dfrac{d\theta_1}{d\lambda_1}\bar{r}_1 + \dfrac{d\theta_2}{d\lambda_2}\bar{r}_2}{\sum_i \dfrac{1}{g_1^{ef''}} - \sum_i \dfrac{1}{u_i''}} d\lambda_i$.

Note that the denominator of this term is always positive as $g_i^{j''} > 0$ and $u_i'' < 0$. Thus, the sign of $dp_{i'}$ depends solely on the numerator, which can be negative, positive or zero. If $dp_{i'} < 0$, then $dW_i^x < 0$ when state i is net exporter of electricity or $f_{ii'} > 0$ and $dW_i^x > 0$ when state i is net importer of electricity or $f_{ii'} > 0$. Otherwise, if $dp_{i'} > 0$, then $dW_i^x < 0$ when state i is net importer of electricity and $dW_i^x > 0$ when state i is net exporter of electricity.

The second term in (16), $dW_i^e \gtreqless 0$, is the *permit market term of trade effect (PME)* in state i. This equals the difference between the total amount of permits demanded under interstate trading, e_i, and the total amount of permits supplied, $\bar{e}_i$, times the negative of the change in the permit price from allowing permit trading between states in state i, $d\lambda_i$. When state i is the net exporter of permits, its permit price increases after trade, $d\lambda_i > 0$, and its CO_2 emission is unbinding $e_i - \bar{e}_i < 0$, therefore its PME is positive. However, if state i is net importer of permits, its PME is negative.

Since state level welfare, dW_i, is the sum of these two terms, it can be positive, zero, or negative. Put simply, moving from intra-state to inter-state permit trading could lower welfare for some states. Therefore, inter-state permit trading generally will not be Pareto superior to intra-state trading across all states.

We can also define the national change in welfare from moving from an intra-state trading regime to an inter-state trading regime:

$$dW = \sum_i dW_i = \underbrace{f_{ii'}\left(dp_{i'} - dp_i\right)}_{dW^x} + \underbrace{(-1)\sum_i \left(e_i - \bar{e}_i\right) d\lambda_i}_{dW^e} + \underbrace{\left(p_{i'} - p_i\right) df_{ii'}}_{CR} \tag{17}$$

As we can observe here in (17), the change in national aggregate surplus can also be decomposed as the sum of three terms.

The first term, dW^x, is the *net electricity market term of trade effect (NEME)*. Assuming state i is net exporter of electricity, this term is then measured as the difference in electricity price changes between the importer state i' and the exporter state i, multiply by the net flow of electricity from i to i'. If the network is not constrained before and after allowing permit trading, price changes in both nodes are the same and so this term is zero. However, if the network is not constrained either before or after allowing permit trading between states, or is constrained both before and after, this term can be positive, zero, or negative.

The second term, dW^e, is the *net permit market term of trade effect (NPME)*. This term equals the sum across states of the difference between the amount of permits supplied and the amount of permit demanded after emission trading, times the negative of the change in permit prices from adopting interstate allowance trading. Under no transmission constraint, the net permit market term of trade effect cannot be negative ($dW^e > 0$). This is because $e_i > \bar{e}_i$ and $d\lambda_i$ cannot be observed simultaneously for all i.[10] When emission caps are binding for both states, this term is always zero.

The last term, $CR = (p_{i'} - p_i)\, df_{ii'}$, is the *congestion rent effect (CRE)*. This term equals the difference between prices of electricity between the two states multiply the change in net flow between them. If transmission is unconstrained or the transmission constraint is never binding both before and after trade, CRE is zero and thus, $dW = dW^e$ and allowing inter-state permit trading is potentially Pareto superior. That is, if states could costlessly negotiate a side payment between them, allowing inter-state permit trading would not lower any state's welfare and would increase the welfare of at least one of them. Yet, because individual aggregate surplus needs not be jointly positive across all states and because side payment negotiations are likely to be costly or restricted, inter-state permit trading may not be selected. Unlike the sum of all PME which reflects the total efficiency gain from allowing inter-state trading, the EME reflects a purely distributional transfer of wealth across states as a result of moving to inter-state trading and which is counterbalanced by terms of opposite sign by the other state.

If transmission is constrained, either under intra-state or inter-state permit trading, or constrained under both regimes, then this story is complicated further and dW need not equal dW^e. Consider the simplest of these three cases when transmission is not binding or unconstrained under intrastate allowance trading, but binding under interstate trading. In that case, $dp_{i'} - dp_i \approx p_{i'}^{AT} - p_i^{AT}$, and dW^x thus reflects a congestion rent effect. Since i' is assumed to be an electricity importer, $p_i^{AT} - p_i^{AT} > 0$ and $f_{ii'} > 0$. This electricity market term of trade now provides an additional welfare due to the gain in congestion rent in state i after allowing interstate permit trading. Since $dW^e > 0$ then so must $dW > 0$. On the other hand, when transmission is binding under intrastate trading but not binding or unconstrained under interstate trading, the electricity market term of trade will

[10] See the Appendix for details.

be negative because of a foregone congestion rent in state i after allowing permit trading between states.[11]

5 Numerical Results

My numerical model captures the inter-regional dispatch of power across five regions/nodes within PJM as of 2017. The model explicitly accounts for pre-existing regulatory distortions such as state-level Renewable Portfolio Standards, federal emissions standards, and federal production and investment tax credits for certain clean EGUs. Electricity dispatch is determined by a central operator who meets supply and demand in every load segment across a year to maximize the aggregate surplus of all consumers and producers located throughout the network. The five regions are constructed by aggregating 22 PJM load zones given similarities in locational marginal prices (LMPs) and geographic proximity. Using PJM total load duration curves for each season and daily natural gas spot prices, I construct 24 representative load segments for each season based on descending order of loads and descending order of gas prices, for 96 total load segments. Load (demand) by node and load segment is assumed to be linear. The model considers 843 representative existing EGUs as of 2017, which are aggregated from over 3,000 units linked to the five nodes based on similarity in fuel types, marginal costs, locations (states and load zones), heat rates, and emission intensities. Marginal costs include fuel costs, variable operation and maintenance costs, SO_2 and NOx emissions permit costs, which are assumed to be linear in generation. All fuels are assumed to be perfectly elastically supplied although I allow fuel prices to reflect observed daily and seasonal variation, which is then averaged across load segments. New natural gas combined cycle, wind, and solar capacity can be added at each node on an annual basis. Transmission reflects the aggregate interregional flow of power between select regions within PJM which may be constrained and which generates losses. For state RPS's, I allow for some RECs to be supplied from sources outside of PJM.

The data used to calibrate the model comes from multiple sources including: the U.S. Environmental Protection Agency's National Electric Energy Data System, Emissions and Generation Resource Integrated Database, Continuous Emissions Monitors and SNL (for details of power plants), the U.S. Energy Information Agency (for nuclear, coal, oil and fuel transportation prices), the International Renewable Energy Agency (for estimates of capital costs for new wind and solar units), PJM data miner 2 (for hourly load and LMPs and unit retirements), PJM-EIS Generation Attribute Tracking System (for imports and exports of RECs in PJM states that are not NC and MI), North Carolina Renewable Energy Tracking System (for imports and exports of RECs in NC), Michigan Renewable Energy Certification System (for imports and exports of RECs in MI), Market Monitoring Analytics

[11] This suggests it is possible for $dW < 0$, yet we have not observed this in our tens of thousands of numerical analyses. I am still working on a proof that would prove that.

(for generation by fuel type and capacity factors by fuel type), and Bloomberg (for daily natural gas spot prices for 2016, 2017 and 2018). Transmission constraints are numerically calibrated to match load-weighted average congestion LMPs between regions in 2016. I also numerically calibrate capital costs of new generation (net of expected future revenue) and the share of external RECs supplied in 2017 so that my model predicts observed 2017 new capacity additions and generation-weighted REC prices. In contrast to many numerical models of this kind, I validate my model for the year 2018 by comparing model predictions to observed 2018 data across several dimensions: REC prices, zonal LMPs, predicted new capacity, and generation mix. In general, my model performs very well. Full details on model calibration and validation are provided in the Appendix.

My model is run annually for years 2019 to 2030, taking into account of scheduled retirements of EGUs in PJM by 2021. Annual load growth is 0.42% based on actual loads of the past five years in PJM as reported by the Market Monitoring Analytics in the State of the Market Reports 2013-2018. Fuel prices are grown from the 2018 fuel price baseline using fuel price growth rates from the 2018 Annual Energy Outlook (AEO 2018) for the Mid-Atlantic region published by the EIA. For capital cost, I assume no growth rate for new natural gas capacity, an annual average reduction of 1.7% for new wind capacity (Wiser et al., 2016) and an annual average reduction of 2.19% for new solar capacity (EIA Sunshot Initiative, 2017). Details of growth rates in RPS targets by state can be found in the Appendix.

5.1 Impact of Moving from No Policy to Intra-state Trading

Impact of CPP on GHG Emissions

The first row of each panel in Table 1 reports the GHG emissions predicted by my model prior to the introduction of the CPP for the years 2022, 2026, and 2030, and cumulatively between 2022 and 2030, the years the CPP was expected to be in effect. For Pennsylvania (top panel), GHG emissions under the baseline are expected to rise gradually from 92.44 $MMTCO_2$ in 2022 to 94.74 $MMTCO_2$ by 2030, with cumulative business as usual GHG emissions from 2022 to 2030 of 844.44 $MMTCO_2$. The last two rows in the panel report mass-based standards assigned to Pennsylvania under the CPP which targeted existing affected EGUs and the state permit prices under intra-state trading. The cumulative emissions cap between 2022-2030 is 771.62 $MMTCO_2$, corresponding to intended GHG emissions reductions of 72.82 $MMTCO_2$, or 8.6% relative to no policy. However, actual GHG emissions actually increase between 2022 and 2030 by 16.88 $MMTCO_2$, reflecting a leakage rate in Pennsylvania of 123.2% (= (72.82+16.88)/72.82); that is, under the CPP with intra-state trading, GHG emissions under are expected to increase as new EGUs that are uncovered by the CPP are endogenously added to the system.

For Rest of PJM (bottom panel), GHG emissions under the baseline are 299.36 $MMTCO_2$ in 2022, falling to 287.19 $MMTCO_2$ in 2026, and then increasing to 292.51 $MMTCO_2$ by 2030, with cumulative business as usual GHG emissions from 2022 to 2030 of 2,627.19. The cumulative emissions cap assigned to RPJM under the mass-based standards assigned to states within RPJM between 2022-2030 is 2,249.15 $MMTCO_2$, corresponding to intended GHG emissions reductions of 378.04 $MMTCO_2$, or 14.4% relative to no policy. However, actual GHG emissions reductions between 2022 and 2030 are just 215.29 $MMTCO_2$, reflecting a leakage rate in RPJM of 43.1% (= (378.04-215.29)/378.04).

The first six rows of each panel in Table 2 show my model predicted generation-weighted REC prices by tier in 2022, 2026, 2030 and average for 2022-2030 in Pennsylvania and RPJM under no policy and intra-state trading. The last two rows in each panel record the RPS targets by tier in each region. In Pennsylvania, all the RPS targets stay the same throughout the nine years, with tier 1 RPS target being 8%, tier 2 RPS target being 10% and solar RPS (SRPS) target being 0.5%. Tier 2 RPS in Pennsylvania is never binding and thus the state observes tier 2 REC prices of zero in all years. Tier 1 REC prices and SRPS prices decline over the years reflecting the extra amount of renewable capacities being added over the years that make the RPS constraints easier to satisfy. Moving to intra-state trading, overall REC prices decline which means the RPS constraints are easier to satisfy when interacting with the CPP. RPJM observes a similar story as REC prices decline over the years and across regimes, even though RPJM's tier 1 RPS targets get stricter over the years, starting with 10% in 2022, to 14% in 2026 and 15% in 2030.

Declining REC prices over time in both Pennsylvania and RPJM means that given the same RPS target, the implicit subsidies for clean EGUs and the implicit tax for dirty EGUs are increasing over time, resulting in disincentives for dirty EGUs to expand and an incentive for clean EGUs to come online more. This is the case that is observed in both Pennsylvania and RPJM under no policy in Table 3. In Pennsylvania, the declining REC prices and constant RPS target drive more renewable capacity expansion over time. In RPJM, the increase in renewable capacity expansion over time is the result of two opposite effects, the effect of declining REC prices and the effect of increasing RPS targets. The former effect, as mentioned above, encourages more clean EGUs to come online. The latter effect, however, decreases implicit subsidies for clean EGUs, therefore, discourages more clean EGUs to be expanded (as subsidy for clean technologies decreasing in RPS target and tax for dirty technology increasing in RPS target). In this case, the former effect dominates the latter effect, resulting in more renewable energy capacity expansion in RPJM. Moving from no policy to intra-state trading, although the REC prices fall and RPS targets are the same as under no policy, the capacity markets in both Pennsylvania and RPJM observe a lot more natural gas capacity expansion due to the interaction of the RPS with the CPP that reshuffles generation between old and new EGUs that eventually causes the emission leakage mentioned above. I explain more about the effects on capacity expansion as markets move from no policy to intra-state trading in the next sub-section.

Impacts of CPP on Capacity Expansion

The first two columns of each panel in Table 3 shows the amount of capacity expanded in Pennsylvania and RPJM in different time periods under no policy and intra-state trading. Prior to 2022, the CPP is not yet implemented thus the amounts of capacity expanded in both regimes are the same. In Pennsylvania from 2022 to 2030 with the RPS target being more lenient than RPJM and staying the same, under no policy, no new natural gas is expanded but 0.11 GW of wind and 0.03 GW of solar are added reflecting the declining REC prices in Pennsylvania as shown in Table 2. Moving from no policy to intra-state trading, permit prices occur, making total electricity prices higher despite REC prices decrease, and incentivize for new natural gas EGUs to come online as they are paid more. Therefore, under intra-state trading, 7.03 GW of new natural gas capacity is added in Pennsylvania while the amounts of new wind and solar capacities almost remain the same compared to under no policy (0.12 GW of new wind and 0.03 GW of new solar).

On the other hand, in RPJM, RPS targets are stricter and gradually increase from 2022 to 2030, driving the state's significant expansion of renewable capacities to keep up with these rising RPS targets. Between 2022 and 2030, under no policy, RPJM expands 14.52 GW of new wind and 0.42 GW of new solar while similar to Pennsylvania, there is no new natural gas capacity expanded in RPJM. Moving from no policy to intra-state trading, RPJM observes a similar pattern with Pennsylvania in which RPJM sees a significant amount of new natural gas capacity being expanded (4.49 GW) due to the lower REC prices, a very similar amount of wind capacity expanded (14.53 GW) and a smaller amount of solar capacity expanded (0.21 GW) compared to no policy.

Intra-state trading CPP incentivizes more natural gas capacity expansion because the emissions from these new natural gas EGUs are not counted under the CPP emission caps and as shown previously in Table 4, both Pennsylvania and RPJM reduce their electricity generation from older EGUs that are covered under the CPP to make room for more electricity generation from new EGUs to be added and still can satisfy the RPS constraints.

Impact of CPP on Electricity Markets

Table 4 shows the effects from moving from no policy to intra-state trading on the electricity markets. The first two rows of each panel in report the average electricity prices prior to the CPP and the changes in average electricity prices from moving to intra-state trading CPP for the years 2022, 2026, and 2030, and averaged between 2022 and 2030. The rest 14 rows in both panels report net flow of electricity, total demand, total generation and breakdown of generation by the years its EGUs are added, and their changes as the regions move to intra-state trading. In Pennsylvania, prior to CPP, electricity prices gradually increase then start to fall in 2026 and rise again in 2030. Between 2022 and 2030, the average electricity price in Pennsylvania is $33.65 prior to the CPP. The CPP with intra-state trading raises the average electricity price in Pennsylvania by $1.80. Before the CPP, Pennsylvania, having a lower electricity price relative to RPJM on average, is a net exporter of electricity. Between 2022 and 2030, Pennsylvania cumulatively exports approximately 637 thousand GWh to RPJM. After the CPP, Pennsylvania becomes an even greater exporter of electricity, increasing net exports by 83.01 thousand GWh. While demand increases little across years (0.4%) and between regimes (0.3%), total electricity generation in Pennsylvania increases around ten times faster as the region moves from no policy to intra-state trading (3%). Consistent with the results in Table 1, the increase in generation in Pennsylvania occurs only in new EGUs due to capacity expansion of natural gas, while generation from older EGUs decline to comply with the emissions cap assigned under the CPP.

On the other hand, in RPJM prior to CPP, electricity prices gradually increase from $35.78 in 2022 to $36.48 in 2030. Between 2022 and 2030, the average electricity price in RPJM is $36.34. Adopting intra-state trading raises the average electricity price in RPJM by $2.06. RPJM, having larger electricity prices prior to and after the CPP, is a net importer of electricity before and after the CPP. Between 2022 and 2030, RPJM cumulatively imports approximately 637.37 thousand GWhs from Pennsylvania before CPP and an additional 83 thousand GWh after the CPP. Although demand decreases very little in RPJM across years (-0.4%) and between regimes (-0.3%), total generation in RPJM decreases a lot more as the region moves from no policy to intra-state trading (-2%). Despite the decline in total generation in RPJM across the nine years, similar to Pennsylvania, the region also experiences a rise in generation from new EGUs that offsets the decrease in generation from older EGUs.

The first panel of Table 5 breaks down net electricity flows in Table 4 into regional electricity flows. The first two rows in the first panel show total electricity flow and change in total electricity flow within Pennsylvania in 2022, 2026, 2030 and cumulatively until 2030. Prior to the CPP, Pennsylvania flows 194.4 thousand GWh from its eastern region to its western region. Moving to intra-state trading, as Pennsylvania export more electricity to RPJM, electricity flow within Pennsylvania decreases by 57.2 thousand GWh, which amounts to 29.4%. Consistently, since RPJM receives more electricity flow from Pennsylvania post trade, electricity flow within RPJM increases by 65.4 thousand GWh, which is 45.7%. On the other hand, Pennsylvania increase its electricity flow cross-border to RPJM by more than 83 thousand GWh, corresponding to 13.1% increase in flow compared to its flow under no policy. The majority of this extra cross-border flow is from West Pennsylvania to West RPJM (79.9 thousand GWh or 12.6%), showing that this line is the least congested. The magnitude of the change in congestion mark-ups between Pennsylvania and RPJM goes up by $0.47, of which then change in congestion mark-up between East Pennsylvania and East RPJM is the most significant ($0.71) followed by the change in congestion mark-ups between East Pennsylvania and Central RPJM ($0.65). This shows that the transmission line between East Pennsylvania and East RPJM is the most congested, second by the line between East Pennsylvania and Central RPJM. The last line between West Pennsylvania and West RPJM is the least congested and therefore still has the capacity to flow the most electricity across the two regions.

Impacts of CPP on Welfares

Table 6 shows the impact of the CPP on aggregate surplus. The first rows in all three panels report the changes in total change in welfares in Pennsylvania, RPJM and PJM as a whole. Moving from no policy to intra-state trading costs PJM more than \$3.14 billion, most of which occurs in RPJM, with Pennsylvania gaining \$ 275 million and RPJM losing \$3.12 million and the cost of congestion rent is increased by 298 million. Rows 2-10 in the first and second panels show the break-downs of the electricity market term of trade effect (EME) in Pennsylvania and RPJM. According to the analytic model (16), EME in Pennsylvania depends on the electricity flow from Pennsylvania to RPJM and the change in electricity price in RPJM from moving to intra-state. Since Pennsylvania is an exporter of electricity, flowing over 83 thousand GWh to RPJM under now policy as shown in Table 4 and the change in electricity price in RPJM is \$2.06, as a result, according to the analytic model, Pennsylvania's EME should be negative. However, my numerical result shows Pennsylvania actually gains from the CPP. This shows that the EME is more complicated than it appears in the analytic model because of the interaction between the CPP and the RPS changes the compositions of dispatched generation. The complexity of the interaction between CPP and RPS can flip the signs of terms as determined in a simple analytic model. In my numerical model, the EME consists of changes in consumer surplus, producer surplus and capital cost for new capacity added in the same year. In Pennsylvania, consumers bear the costs of the CPP intra-state trading due to increases in electricity prices that amount to a decrease in consumer surplus of approximately -\$ 2.6 billion. Producers of electricity benefit from the rise in electricity prices and gain the total producer surplus of over \$3.3 billion. As shown in Table 3 that CPP incentivize a lot of new natural gas capacity expansion, the change in capital cost of new capacity expanded is mostly made up of the cost of expansion of new natural gas EGUs, which amounts to over \$ 510 million. The last three rows in the first and second panels show the break-downs of the permit market term of trade effect (PME) in Pennsylvania. Since under intra-state trading, there is no permit trading between Pennsylvania and RPJM, the numbers of permits bought and sold within each region have to equalize. Thus under intra-state trading, this term is always zero. As a result, total aggregate surplus in Pennsylvania under intra-state trading depends solely on the EME. Overall, in Pennsylvania, the gain in producer surplus is dominant over the loss in consumer surplus and total new capital cost and thus Pennsylvania observes a net gain in its EME which means a net gain in its total aggregated surplus from moving from no policy to intra-state trading.

Similar to Pennsylvania, in RPJM, consumers also bear the costs of the CPP intra-state trading due to increases in electricity prices that amount to a decrease in consumer surplus of approximately -\$ 14.1 billion. On the suppliers' side, producers of electricity also benefit from the rise in electricity prices and gain the total producer surplus of over \$11.2 billion. The change in capital cost of new capacity expanded is over \$ 510 million. Unlike in Pennsylvania, in RPJM, the loss in consumer surplus dominates the net gain in producer surplus and thus RPJM observes a net loss in EME which means a net loss in its total aggregated surplus from moving from no policy to intra-state trading.

The last panel of Table 6 report the decomposition of change in welfares in PJM as a whole, which is made up of three terms consistently to the analytic formula: The net electricity market term of trade effect (NEME), the net permit market term of trade effect (NPME) and the congestion rent (CR). Since the NPME is always zero, the NEME in this case equals to the sum of the total changes in aggregate surplus in Pennsylvania and RPJM, which amounts to -$2.9 billion. Since intra-state trading increases congestion in the transmission network, we see an increase in the magnitude of the net congestion rent by -$298 million in PJM cumulatively by 2030. The total cost of moving from no policy to intra-state trading in PJM is $3.14 billion, which is made up of the cost of -$ 2.9 billion from the NEME and the -$298 million from CR.

5.2 Impacts of Moving from Intra-state Trading to Inter-state Trading

Impacts of Moving from Intra-state Trading to Inter-state Trading on GHG Emissions:

The first row of each panel in Table 7 reports the GHG emissions predicted by my model under intra-state trading for the years 2022, 2026, and 2030, and cumulatively between 2022 and 2030. Total emissions in PJM under intra-state trading go from 374.03 million metric tons in 2022 to 358.35 million metric tons in 2030. The second row in each panel reports the total changes in emissions realized under CPP's inter-state trading compared to intra-state trading. The last two rows report the permit prices under intra-state trading and the changes in permit prices from moving to inter-state trading. Prior to entering inter-state trading, Pennsylvania has lower permit prices than RPJM and these prices increase over time, from $1.27 in 2022 to $4.43 in 2030. Because Pennsylvania is the cleaner state and has lower permit prices across the years, it is always the net exporter of permits. After trading, Pennsylvania's permit prices increase until they equalize to RPJM's decreasing permit prices. Since it is cheaper for Pennsylvania to abate, Pennsylvania observes a decrease in total emission across the years, from -$8.32 million metric tons in 2022 to -$15.09 million metric tons in 2030, most of which still comes from emissions reduction from older EGUs that are covered under CPP. Emissions in Pennsylvania still increase in new uncovered EGUs added in between 2022 and 2029. Thus, Pennsylvania still observes emission leakage in new uncovered EGUs under inter-state trading. This is because Pennsylvania, being the state with more lenient RPS target can still afford to expand more new gas capacity under inter-state trading to displace the older non-dispatched emitting EGUs.

On the other hand, prior to entering inter-state trading, RPJM, being the dirtier state, has higher permit prices than Pennsylvania and these prices also increase over time, from $3.95 in 2022 to $7.07 in 2030. Because RPJM is the dirtier state and has higher permit prices across the years, it is always the net importer of permits. After trading, RPJM's permit prices decline until they equalize to Pennsylvania's increasing permit prices. Since it is more expensive for RPJM to abate, RPJM emits more using permits bought from Pennsylvania. Thus, RPJM observes an increase in total emission across the years, from \$9.54 million metric tons in 2022 to \$15.80 million metric tons in 2030, most of which comes from emissions reduction from new EGUs that are uncovered under CPP. As shown in Table 3, inter-state trading changes the distribution of new natural gas capacity expansion in PJM compared to intra-state trading with Pennsylvania expands more natural gas capacity and RPJM expands less. This is because RPJM, being the state with more stringent RPS target, has to cut down its capacity expansion of new gas EGUs, as it now dispatches more older emitting EGUs more cheaply.

Moving from intra-state to inter-state trading observes a fall in REC prices in Pennsylvania and an increase in REC prices in RPJM across the years, as shown in Table 8. With the declining REC prices, Pennsylvania buys more external RECs from outside of the PJM which affords the state to increase dirty generation and still satisfy its RPS. On the other hand, with the higher REC prices post-trade, RPJM buys less external RECs and RPJM reduces its total dirty generation (including expand less new natural gas capacity) to satisfy its tighter RPS targets.

Impacts of Moving from Intra-state Trading to Inter-State Trading on Capacity Expansion:

The last two columns of Table 3 reports the amount of capacity expanded in Pennsylvania and RPJM in different time periods under intra-state trading and inter-state trading. Moving from intra-state trading to inter-state trading, even more new gas capacity is expanded overall in PJM. 13.74 GW of new natural gas capacity is added in PJM from 2022 to 2030 under inter-state trading, but the new gas capacity is distributed more in Pennsylvania and less in RPJM. On the other hand, 13.45 GW of wind and 1.32 GW of solar are expanded under inter-state trading compared to 13.55 GW of wind and 1.34 GW of solar are expended under intra-state trading. This shows that trading do not incentivize new adoption of new renewable resources.

Impacts of Moving from Intra-state Trading to Inter-State Trading on Electricity Markets:

Table 4 shows the impacts of moving from intra-state trading to inter-state trading on the electricity market. The first two rows of each panel report the average electricity prices prior to trading and the changes in average electricity prices from moving to inter-state trading for the years 2022, 2026, and 2030, and averaged between 2022 and 2030. The rest 14 rows in both panels report net flow of electricity, total demand, total generation and breakdown of generation by the years its EGUs are built, and their changes as the regions move to inter-state trading. In Pennsylvania, prior to trade, electricity prices gradually increase then start to fall in 2027 and rise again in 2030. Over the 9 years, the average electricity price in Pennsylvania is \$35.45. Adopting inter-state trading lowers electricity price in Pennsylvania by \$0.08. Before trade, Pennsylvania, having lower electricity price than RPJM and thus, is the net exporter of electricity. By 2030, Pennsylvania cumulatively exports approximately 717.4 thousand GWh to RPJM under intra-state trading. After trade, Pennsylvania reduces its export of electricity by over 82.3 thousand GWh. Demand is very inelastic and does not change between regimes, however total generation in Pennsylvania decreases by over 212 GWh as the state adopt trading. Consistently with the results in Table 7, even though Pennsylvania produces less total electricity generation post-trade, it still produces more electricity generation in new EGUs due to extra capacity expansion of natural gas, while generation from older EGUs falls to hold more permits to sell to RPJM.

On the other hand, in RPJM under intra-state trading, electricity prices gradually increase from \$36.97 in 2022 to \$39.35 in 2030. Over the 9 years, the average electricity price in RPJM is \$37.38. Adopting intra-state trading lowers electricity price in RPJM by \$0.07. RPJM, having higher electricity prices prior to trade, is the net importer of electricity before and after trade, although it becomes a smaller importer of electricity after trade. By 2030, RPJM cumulatively imports approximately 717.4 thousand GWh from Pennsylvania before trade and 635 thousand GWh after trade, equivalent to a fall of 82.35 thousand GWh of electricity generation. Similar to Pennsylvania, demand in RPJM is also very inelastic and remains unchanged across trading regimes, total generation in RPJM increases by 1.5% as the region adopts trading and uses the permits bought from Pennsylvania to cover more electricity generation. Since RPJM already increases their generation from old EGUs, it reduces their generation from new EGUs to comply with their RPS.

The next Table, Table 10 report the changes in electricity flows to different regions within PJM and congestion mark-ups from moving to inter-state trading. The first panel breaks down net electricity flows in Table 9 into regional electricity flows. The first two rows in the first panel show display electricity flow and change in total electricity flow within Pennsylvania in 2022, 2026, 2030 and cumulatively until 2030. Pior to trade, Pennsylvania cumulatively flows 137.1 thousand GWh from its eastern region to its western region. Moving to inter-state trading does not impact internal flow of electricity flow within Pennsylvania very much (only 2% decrease in flow). On the other hand, since RPJM buys permits from Pennsylvania after trade and produces more electricity post trade, electricity flow within RPJM increases by 27.5 thousand GWh, which is 35.4%. As Pennsylvania becomes a smaller exporter of electricity post trade, the cross-border flow between Pennsylvania and RPJM falls by 82.4 GWh, corresponding to 11.5% decrease in flow compared to under intra-state trading. The majority of this reduction in cross-border flow is from West Pennsylvania to West RPJM (80 thousand GWh or 11.2%), making this flow similarly to under no policy. The magnitude of the change in congestion mark-ups between Pennsylvania and RPJM is very little (only by \$0.02), of which then change in congestion mark-up between East Pennsylvania and East RPJM reflects a congestion relief in this line (\$0.29) and the change in congestion mark-ups between East Pennsylvania and Central RPJM reflects an increase in congestion in this line (\$0.27). This means inter-state trading helps relieve congestion from the most congested line which is between East Pennsylvania and East RPJM. However, overall as we can see in the congestion prices, moving to inter-state trading makes very minimal changes overall in the congestion price between Pennsylvania and RPJM.

Impacts of Moving from Intra-state Trading to Inter-state Trading on Welfares:

In the last Table, Table 11, we look at the changes in welfares from moving from intra-state trading to inter-state trading. The first rows in all three panels report the changes in total change in welfares in Pennsylvania, RPJM and PJM as a whole. Similar to Table 6, rows 2-10 in the first and second panels show the break-downs of the EME in Pennsylvania and RPJM. This term consists of changes in consumer surplus, producer surplus and capital cost for new capacity added in the same years. In Pennsylvania, consumers benefit from trade due to the fall in electricity prices that amount to a gain in consumer surplus of $ 76.2 million. Producers of electricity bear the cost of the fall in electricity prices and lose the total producer surplus of -$712 million. Inter-state trading also brings in 4.44 GW of new natural gas capacity in Pennsylvania as shown in Table 3. Because of this, Pennsylvania also pays extra $ 244 million for capital cost of expanding these new gas EGUs. The last three rows in the first two panels are the decompositions of the PME in Pennsylvania and RPJM as they adopt permit trading. In the permit market, Pennsylvania sees a rise in permit prices due to trade and therefore gains over $1.1 billion in value of permits sold to RPJM. However, since permit price in RPJM declines due to trade, Pennsylvania's value of permits bought from RPJM declines as well. With both of these effects combined, Pennsylvania still has a net gain in the PME of $ 800 million. Overall, moving from intra-state trading to inter-state trading, Pennsylvania's negative EME dominates its positive PME, resulting a total loss of aggregate surplus of $79.1 million.

Contrast with Pennsylvania, moving to inter-state trading results in a gain in the EME and a loss in the PME in RPJM. The gain in EME is due to gains in all producer surplus, consumer surplus and new capital cost. The gain in consumer surplus is obvious, as electricity price has gone down in RPJM as well as shown in the second panel of Table 9. The gain in producer surplus is due to the increase in total electricity generation in RPJM as the region buys permits from Pennsylvania to cover this additional generation. And the gain in the new capital cost is because under inter-state trading, RPJM expands less capacity, mostly in natural gas, compared to under intra-state trading as the region's capacity expansion is limited by its RPS constraint. Consistent with the results for Pennsylvania above, in the permit market, RPJM's declining permit price and Pennsylvania's rising permit price due to trade result in the region's loss in its value of permit sold and gain in the value of permits bought from Pennsylvania, netting out to a total loss of $ 800 million in PME, equalizing in magnitude with the gain in PME in Pennsylvania. Overall, moving from intra-state trading to inter-state trading, RPJM's positive EME dominates its negative PME, resulting a total gain of aggregate surplus of $56.01 million. The last panel of Table 11 report the decomposition of change in welfares in PJM as a whole, which is made up of three terms,as described in the last panel of Table 6, NEME, NPME and CR. NPME is always zero as the gain in PME in Pennsylvania equates the loss in PME in RPJM. Therefore the NEME in this case also equals to the sum of the total changes in aggregate surplus in Pennsylvania and RPJM, which amounts to -$23.1 million. Since inter-state trading relieves congestion in the transmission network, we see a gain in the net congestion rent by$195.9 million in PJM cumulatively by 2030. PJM gains $172.9 million cumulatively from 2022 to 2030 from moving from intra-state trading to inter-state trading, with Pennsylvania losing $ 79.1 million and RPJM gaining $56 million and the payment of congestion rent is increased by $195.9 million. Overall, in this case, inter-state trading is unlikely to occur since without redistribution of congestion payments or side payments, RPJM is the only region benefits from trade. However, if congestion payment is redistributed so that Pennsylvania gets all the congestion payment within its border or get both the congestion payment within its border and the congestion payment cross border between Pennsylvania and RPJM, inter-state trading is likely to occur since both regions now gain from trade.

6 Conclusion

In this paper, I studied states' incentives to participate in voluntary inter-state trading under the Clean Power Plan. States would have incentives to adopt trade ready plans when their change in welfare after trading is positive. Inter-state trading will only emerge as the equilibrium when both states adopt trade ready plans, that is when both states gain simultaneously from moving to interstate trading. I develop an analytic model which provided simple formulas to decompose the change in welfare in each state and the change in national welfare. I then conduct a numerical analysis to evaluate how actual complexities in a regional electricity wholesale market affect the incentives to adopt trade ready plans. I also evaluate numerically the critical implications of interactions between the CPP and state-level performance standards such as the RPS on these decisions.

This paper identified several important findings. First, I showed that in most cases, the change in national welfare is positive, which means that from the perspective of a national regulator, inter-state permit trading most likely implies lower costs and thus greater welfare. However, states may not choose to adopt trade ready plans because individual states may lose from moving to inter-state permit trading from intra-state permit trading.

Second, I show that both states can still benefit from inter-state trading when congestion payment is redistributed to compensate for the state that experiences a loss from trade. In the case of the PJM, without congestion payment, Pennsylvania occurs a loss of $79 million due to trade, which can be easily compensated with congestion payment for transmission activities within Pennsylvania alone without any loss to RPJM. Therefore, if Pennsylvania is also the transmission owner of all the transmission lines within itself, inter-state trading is likely to occur.

Third, my numerical model shows the clear effects of interactions between federal policies and state-level performance standards. I numerical show that the RPS is an effective policy tool to incentivize adoption of new renewable resources and lower the price of renewable energy. When the CPP is added on top of the RPS, however, a significant amount of natural gas capacity is expanded due to changes in generation dispatch, resulting in emission leakage.

Tables

Table 1: Impacts of Moving from No Policy to Intra-state Trading under Mass-based Standard on the Emission Market.

	2022	2026	2030	Cumulative
Pennsylvania:				
Emissions under No Policy (million metric tons)	92.44	93.51	94.74	844.44
Change	1.99	0.05	4.60	16.88
Due to Units Built in Pre 2019	-2.37	-7.82	-13.16	-72.74
Due to Units Built in 2019 to 2021	0.04	0.00	-0.09	-0.09
Due to Units Built in 2022 to before Current Year	0.00	7.86	13.44	85.30
Due to Units Built in Current Year	4.32	0.00	4.41	4.41
Emission Cap	90.11	85.69	81.49	771.62
Permit Price under Intra-state Trading ($/ton CO_2)	1.27	3.05	4.43	2.94
Rest of PJM:				
Emissions under No Policy (million metric tons)	299.36	287.19	292.51	2,627.19
Change	-19.76	-19.97	-33.50	-215.29
Due to Units Built in Pre 2019	-36.62	-37.34	-54.89	-377.76
Due to Units Built in 2019 to 2021	-0.07	-0.07	-0.10	-0.75
Due to Units Built in 2022 to before Current Year	0.00	17.45	20.64	162.37
Due to Units Built in Current Year	16.94	0.00	0.85	0.85
Emission Cap	262.66	249.77	237.52	2,249.15
Permit Price under Intra-state Trading ($/ton CO_2)	3.95	5.35	7.07	5.47

Table 2: Impacts of Moving from No Policy to Intra-state Trading under Mass-based Standard on Generation Weighted REC Prices.

	2022	2026	2030	Cumulative
Pennsylvania:				
REC Price Tier 1 under No Policy ($/MWh)	27.6	21.78	20.18	22.94
Change	-0.42	0.29	-2.37	-1.01
SREC Price under No Policy	23.85	19.06	17.37	18.31
Change	-0.46	-19.06	0.00	-2.51
RPS Target Tier 1	0.08	0.08	0.08	0.08
SRPS Target	0.01	0.01	0.01	0.01

Rest of PJM:				
REC Price Tier 1 under No Policy ($/MWh)	16.05	15.20	12.81	14.71
Change	-4.01	-1.82	-2.26	-2.06
SREC Price under No Policy	11.64	10.09	5.95	9.67
Change	-4.40	-0.11	2.55	-0.60
RPS Target Tier 1	0.10	0.14	0.15	0.13
SRPS Target	0.01	0.01	0.01	0.01

Table 3: Capacity Expansion by Fuel Type.

	No Policy	Intra-state Trading	Inter-state Trading
Pennsylvania:			
New Natural Gas Capacity - 2019 to 2021 (GW)	0.31	0.31	0.31
New Natural Gas Capacity - 2022 to 2029	0.00	6.15	9.93
New Natural Gas Capacity - 2030	0.00	0.88	0.66
New Wind Capacity - 2019 to 2021 (GW)	3.36	3.36	3.36
New Wind Capacity - 2022 to 2029	0.09	0.06	0.00
New Wind Capacity - 2030	0.03	0.01	0.00
New Solar Capacity - 2019 to 2021 (GW)	0.71	0.71	0.71
New Solar Capacity - 2022 to 2029	0.02	0.06	0.02
New Solar Capacity - 2030	0.00	0.02	0.00
Rest of PJM:			
New Natural Gas Capacity - 2019 to 2021 (GW)	0.22	0.22	0.22
New Natural Gas Capacity - 2022 to 2029	0.00	4.32	2.97
New Natural Gas Capacity - 2030	0.00	0.17	0.24
New Wind Capacity - 2019 to 2021 (GW)	3.79	3.79	3.79
New Wind Capacity - 2022 to 2029	12.52	13.30	13.21
New Wind Capacity - 2030	0.40	0.18	0.24
New Solar Capacity - 2019 to 2021 (GW)	0.96	0.96	0.96
New Solar Capacity - 2022 to 2029	2.00	1.23	1.26
New Solar Capacity - 2030	0.02	0.03	0.04

Table 4: Impacts of Moving from No Policy to Intra-state Trading under Mass-based Standard on the Electricity Market.

	2022	2026	2030	Cumulative
Pennsylvania:				
Average Electricity Price under No Policy ($/MWh)	33.79	33.57	33.60	33.65
Change	0.90	2.02	2.34	1.80
Net Flow under No Policy (thousand GWh)	-70.70	-70.56	-69.14	-634.37
Change	-6.34	-5.97	-16.11	-83.01
Demand under No Policy (thousand GWh)	160.80	163.55	166.33	1,472.03
Change	-0.21	-0.50	-0.58	-3.94
Total Generation under No Policy	238.16	240.88	242.35	2,167.33
Change	6.12	5.45	15.51	78.94
Existing Generation under No Policy - Pre 2019	227.51	229.94	231.29	2,069.32
Change	-1.13	-6.72	-12.01	-61.78
New Generation under No Policy - 2019 to 2021	10.64	10.67	10.72	96.07
Change	0.00	0.00	-0.15	-0.21
New Generation under No Policy - 2022 to 2029	0.01	0.26	0.27	1.86
Change	7.24	12.18	20.34	133.51
New Generation under No Policy - 2030	0.00	0.00	0.08	0.08
Change	0.00	0.00	7.34	7.34
Rest of PJM:				
Average Electricity Price under No Policy ($/MWh)	35.78	36.44	36.48	36.34
Change	1.20	2.13	2.87	2.06
Net Flow under No Policy (thousand GWh)	70.70	70.56	69.14	634.37
Change	6.34	5.97	16.11	83.01
Demand under No Policy (thousand GWh)	657.87	669.13	680.53	6,106.50
Change	-1.17	-2.43	-3.44	-21.24
Total Generation under No Policy	614.70	626.31	639.60	5,638.08
Change	-7.82	-8.50	-19.69	-105.44
Existing Generation under No Policy - Pre 2019	599.19	584.25	589.86	5,308.41
Change	-36.20	-35.80	-53.39	-364.39
New Generation under No Policy - 2019 to 2021	12.45	12.45	12.46	112.21
Change	-0.20	-0.12	-0.16	-1.34
New Generation under No Policy - 2022 to 2029	3.05	29.61	36.22	216.41
Change	28.59	27.43	32.98	259.44
New Generation under No Policy - 2030	0.00	0.00	1.07	1.07
Change	0.00	0.00	0.88	0.88

Table 5: Impacts of Moving from No Policy to Intra-state Trading under Mass-based Standard on Congestion Rent.

	2022	2026	2030	Cumulative
Flow into East PA (1) from West PA (2) (thousand GWh)	21.1	21.4	22.5	194.4
Change	-4.1	-5.4	-9.7	-57.2
Flow into Central RPJM (4) from West RPJM (5)	13.9	16.4	17.3	143.2
Change	-9.0	-5.2	-8.4	65.4
Total Cross-Border	-70.7	-70.6	-69.1	-634.4
Change	-6.3	-6.0	-16.1	-83.01
Flow into East PA (1) from East RPJM (3)	-50.3	-50.7	-50.8	-455.6
Change	-0.2	-0.0	0.2	0.0
Flow into East PA (1) from Central RPJM (4)	-10.2	-11.5	-11.3	-99.5
Change	-0.4	0.1	-2.1	-6.6
Flow into West PA (2) from West RPJM (5)	-10.2	-8.4	-7.1	-79.9
Change	-5.8	-6.0	-14.3	-76.7

Congestion Price between East PA (1) and West PA (2) before CPP ($/MWh)	-0.08	0.37	0.60	0.30
Congestion Price between East PA (1) and West PA (2) after CPP ($/MWh)	-0.74	-0.66	-1.26	-0.94
Change	-0.66	-1.03	-1.86	-1.24
Congestion Price between Central RPJM (4) and West RPJM (5) before CPP	0.45	1.39	1.81	1.23
Congestion Price between Central RPJM (4) and West RPJM (5) after CPP	0.06	0.69	0.89	0.59
Change	-0.39	-0.70	-0.91	-0.64
Congestion Price Cross Border before CPP	-2.00	-2.81	-2.77	-2.63
Congestion Price Cross Border after CPP	-2.41	-3.10	-3.62	-3.10
Change	-0.41	-0.29	-0.84	-0.47
Congestion Price between East PA (1) and East RPJM (3) before CPP	-3.55	-6.35	-6.10	-5.68
Congestion Price between East PA (1) and East RPJM (3) after CPP	-4.78	-6.74	-6.90	-6.39
Change	-1.23	-0.39	-0.80	-0.71
Congestion Price between East PA (1) and Central RPJM (4) before CPP	-1.48	-1.55	-1.71	-1.57
Congestion Price between East PA (1) and Central RPJM (4) after CPP	-1.62	-1.95	-3.05	-2.22
Change	-0.13	-0.40	-1.34	-0.65
Congestion Price between West PA (2) and West RPJM (5) before CPP	-0.96	-0.54	-0.51	-0.65
Congestion Price between West PA (2) and West RPJM (5) after CPP	-0.82	-0.60	-0.90	-0.70
Change	0.14	-0.07	-0.39	-0.05

Table 6: Welfare Impacts of Moving from No Policy to Intra-state Trading under Mass-based Standard (in million dollars).

	2022	2026	2030	Cumulative
A. Decomposition of Change in Aggregate Surplus within Pennsylvania				
dW_{PA}, Change in Aggregate Surplus	49.4	32.7	-1.6	275.7
dW_{PA}^{x}, In Electricity Market	49.4	32.7	-1.6	275.7
dCS_{PA}, Change in Consumer Surplus	-136.8	-322.7	-369.7	-2,553.9
Due to Loss	-5.1	-12.1	-13.9	-96.3
Due to Energy Consumption	-131.7	-310.6	-355.8	-2,457.6
dPS_{PA}, Change in Producer Surplus	251.2	391.7	430.90	3,339.9
From Generation added by 2021	171.1	3,351.9	3,660.0	24,774.6
From Generation added from 2022 to 2029	80.1	-2,960.2	-3,303.2	-21,508.8
From Generation added in 2030	0.0	0.00	74.2	74.2
dK_{PA}, In New Capacity	-65.0	-36.4	-62.8	-510.6
dW_{PA}^{e}, In Permit Market	0.0	0.0	0.0	0.0
dCP_{PA}, Change in Cost of Permits Bought	-114.7	-261.4	-354.0	-2,242.2
dVP_{PA}, Change in Value of Permits Sold	114.7	261.4	354.0	2,242.2

B. Decomposition of Change in Aggregate Surplus within Rest of PJM				
dW_{RPJM}, Change in Aggregate Surplus	-179.5	-334.6	-584.7	-3,129.3
dW_{RPJM}^{x}, In Electricity Market	-179.5	-334.6	-584.76	-3,129.3
dCS_{RPJM}, Change in Consumer Surplus	-770.5	-1,616.9	-2,281.2	-14,064.5
Due to Loss	-28.7	-60.0	-85.0	-524.6
Due to Energy Consumption	-741.8	-1,557.0	-2,196.1	-13,539.9
dPS_{RPJM}, Change in Producer Surplus	835.6	1,274.5	1,680.8	11,267.9
From Generation added by 2021	571.2	4,654.1	6,495.5	38,260.3
From Generation added from 2022 to 2029	264.4	-3,379.5	-4,817.2	-27,030.2
From Generation added in 2030	0.00	0.00	2.5	2.5
dK_{RPJM}, In New Capacity	0.0	7.9	15.6	-88.2
dW_{RPJM}^{e}, In Permit Market	0.0	0.0	0.0	0.0
dCP_{RPJM}, Change in Cost of Permits Bought	-1,038.2	-1,336.5	-1,678.3	-12,239.7
dVP_{RPJM}, Change in Value of Permits Sold	1,038.2	1,336.5	1,678.3	12,239.7

C. Decomposition of Change in Aggregate Surplus within PJM				
dW, Change in PJM Aggregate Surplus	-126.6	-339.7	-593.8	-3,141.4
dW_{PA}, In Pennsylvania	49.4	32.7	-1.6	275.7
dW_{RPJM}, In Rest of PJM	-179.5	-334.6	-584.7	-3,129.3
dCR, Change in Congestion Rent	-6.1	-37.8	-7.5	-297.5
dCR_{PA}, In Pennsylvania	-21.9	-20.3	-13.6	-194.9
dCR_{RPJM}, In Rest of PJM	-24.3	-29.6	-48.8	-331.8
dCR_{Other}, In Cross Border Links	40.1	12.0	54.9	229.1
dW^{x}, In PJM Electricity Market	-130.1	-301.9	-586.3	-2,853.5
dW^{e}, In PJM Permit Market	0.0	0.0	0.0	0.0
$dW_{PA} + dCR_{PA}$	27.5	12.4	-15.3	80.8
$dW_{RPJM} + dCR_{RPJM} + dCR_{Other}$	-163.7	-352.1	-578.6	-2,904.6
Ratio	-0.2	-0.0	0.0	-0.03
$dW_{PA} + dCR_{PA} + dCR_{Other}$	67.6	24.4	39.7	309.9
$dW_{RPJM} + dCR_{RPJM}$	-203.8	-364.1	-633.5	-3,461.1
Ratio	-0.3	-0.1	-0.1	-0.06

Table 7: Impacts of Moving from Intra-state Trading to Inter-state Trading under Mass-based Standard on the Emission Market.

	2022	2026	2030	Cumulative
Pennsylvania:				
Emissions under Intra-state Trading (million metric tons)	94.43	93.55	99.34	861.33
Change	-8.32	-10.20	-15.09	-101.26
Due to Units Built in Pre 2019	-16.83	-17.87	-23.82	-191.58
Due to Units Built in 2019 to 2021	-0.06	-0.08	-0.12	-0.82
Due to Units Built in 2022 to before Current Year	0.00	7.75	9.94	75.60
Due to Units Built in Current Year	8.57	0.00	-1.09	-1.09
Permit Price under Intra-state Trading ($/ton CO_2)	1.27	3.05	4.43	2.94
Change	1.32	1.45	1.61	1.55
Rest of PJM:				
Emissions under Intra-state Trading (million metric tons)	279.60	267.22	259.01	2,412.37
Change	9.54	8.92	15.80	99.49
Due to Units Built in Pre 2019	16.85	17.91	23.93	175.28
Due to Units Built in 2019 to 2021	0.04	0.04	0.01	-0.48
Due to Units Built in 2022 to before Current Year	0.00	-9.03	-8.47	-76.37
Due to Units Built in Current Year	-7.35	0.00	0.33	0.33
Permit Price under Intra-state Trading ($/ton CO_2)	3.95	5.35	7.07	5.47
Change	-1.36	-0.86	-1.11	-1.02

Table 8: Impacts of Moving from Intra-state Trading to Inter-state Trading under Mass-based Standard on Generation Weighted REC Prices.

	2022	2026	2030	Cumulative
Pennsylvania:				
REC Price Tier 1 under Intra-state Trading ($/MWh)	27.24	22.07	17.81	21.93
Change	-0.55	-2.31	-0.80	-0.65
SREC Price under Intra-state Trading	23.40	0.00	17.37	15.80
Change	0.55	-0.00	-0.36	-3.13
Rest of PJM:				
REC Price Tier 1 under Intra-state Trading ($/MWh)	12.05	13.38	10.55	12.65
Change	2.30	0.07	0.03	0.28
SREC Price under Intra-state Trading	7.24	9.98	8.50	9.07
Change	0.98	0.03	0.04	0.02

Table 9: Impacts of Moving from Intra-state Trading to Inter-state Trading under Mass-based Standard on the Electricity Market.

	2022	2026	2030	Total
Pennsylvania:				
Average Electricity Price under Intra-state Trading ($/MWh)	34.69	35.59	35.94	35.45
Change	0.01	-0.17	-0.09	-0.08
Net Flow under Intra-state Trading (thousand GWh)	-77.04	-76.53	-85.25	-717.43
Change	5.55	7.86	14.05	82.35
Demand under Intra-state Trading (thousand GWh)	160.58	163.05	165.75	1,466.07
Change	0.00	0.05	0.01	0.02
Total Generation under Intra-state Trading	244.28	246.33	257.87	2,246.27
Change	-5.54	-7.81	-14.04	-82.17
Existing Generation under Intra-state Trading - Pre 2019	226.38	223.22	219.27	2,007.51
Change	-19.80	-21.34	-30.45	-212.14
New Generation under Intra-state Trading - 2019 to 2021	10.64	10.67	10.57	95.86
Change	-0.03	-0.13	-0.19	-1.32
New Generation under Intra-state Trading - 2022 to 2029	7.26	12.44	20.61	135.57
Change	14.29	13.66	18.47	133.16
New Generation under Intra-state Trading - 2030	0.00	0.00	7.42	7.42
Change	0.00	0.00	-1.87	-1.87
Rest of PJM:				
Average Electricity Price under Intra-state Trading ($/MWh)	36.97	38.58	39.35	38.39
Change	-0.26	-0.04	-0.04	-0.07
Net Flow under Intra-state Trading (thousand GWh)	77.04	76.53	85.25	717.39
Change	-5.55	-7.86	-14.05	-82.35
Demand under Intra-state Trading (thousand GWh)	656.70	666.70	677.08	5,991.19
Change	0.15	0.01	0.12	0.38
Total Generation under Intra-state Trading	606.88	617.81	619.91	5,532.67
Change	5.70	7.87	14.18	82.75
Existing Generation under Intra-state Trading - Pre 2019	562.99	548.45	536.47	4,943.96
Change	17.68	19.64	24.97	187.07
New Generation under Intra-state Trading - 2019 to 2021	12.25	12.33	12.29	110.83
Change	0.15	0.06	0.02	0.57
New Generation under Intra-state Trading - 2022 to 2029	31.64	57.03	69.20	475.83
Change	-12.12	-11.83	-11.50	-105.57
New Generation under Intra-state Trading - 2030	0.00	0.00	1.94	1.94
Change	0.00	0.00	0.69	0.69

Table 10: Impacts of Moving from Intra-state Trading to Inter-state Trading under Mass-based Standard on Congestion Rent.

	2022	2026	2030	Cumulative
Flow into East PA (1) from West PA (2) (thousand GWh)	17.0	16.0	12.8	137.1
Change	-1.1	-0.4	0.6	-3.0
Flow into Central RPJM (4) from West RPJM (5)	4.9	11.2	8.8	77.7
Change	3.9	2.1	3.9	27.5
Total Cross-Border	-77.0	-76.5	-85.2	-717.4
Change	5.6	7.9	14.0	82.4
Flow into East PA (1) from East RPJM (3)	-50.5	-50.7	-50.5	-455.5
Change	0.1	0.0	-0.0	0.4
Flow into East PA (1) from Central RPJM (4)	-10.6	-11.4	-13.4	-106.1
Change	-0.2	0.1	1.5	2.9
Flow into West PA (2) from West RPJM (5)	-16.0	-14.4	-21.4	-156.6
Change	5.7	7.8	12.5	80.0

Congestion Price between East PA (1) and West PA (2) before Trade ($/MWh)	-0.74	-0.66	-1.26	-0.94
Congestion Price between East PA (1) and West PA (2) after Trade ($/MWh)	-0.92	-0.82	-1.02	-0.99
Change	-0.18	-0.16	0.23	-0.49
Congestion Price between Central RPJM (4) and West RPJM (5) before Trade	0.06	0.69	0.89	0.59
Congestion Price between Central RPJM (4) and West RPJM (5) after Trade	0.08	0.99	1.09	0.77
Change	0.02	0.31	0.19	0.19
Congestion Price Cross Border before Trade	-2.41	-3.10	-3.62	-2.85
Congestion Price Cross Border after Trade	-2.17	-3.26	-3.63	-2.87
Change	0.24	-0.16	-0.01	-0.02
Congestion Price between East PA (1) and East RPJM (3) before Trade	-4.78	-6.74	-6.90	-6.39
Congestion Price between East PA (1) and East RPJM (3) after Trade	-4.10	-6.61	-6.86	-6.10
Change	0.68	0.13	0.03	0.29
Congestion Price between East PA (1) and Central RPJM (4) before Trade	-1.62	-1.95	-3.05	-2.22
Congestion Price between East PA (1) and Central RPJM (4) after Trade	-1.70	-2.49	-3.06	-2.49
Change	-0.08	-0.54	-0.01	-0.27
Congestion Price between West PA (2) and West RPJM (5) before Trade	-0.82	-0.60	-0.90	-0.70
Congestion Price between West PA (2) and West RPJM (5) after Trade	-0.70	-0.67	-0.95	-0.72
Change	0.12	-0.07	-0.05	-0.03

Table 11: Welfare Impacts of Moving from Intra-state Trading to Inter-state Trading under Mass-based Standard (in million dollars).

	2022	2026	2030	Cumulative
A. Decomposition of Change in Aggregate Surplus within Pennsylvania				
dW_{PA}, Change in Aggregate Surplus	19.4	-23.9	6.2	-79.1
dW^x_{PA}, In Electricity Market	-24.4	-104.6	-136.3	-879.8
dCS_{PA}, Change in Consumer Surplus	-1.6	26.6	6.3	76.2
Due to Loss	-0.2	0.8	0.1	1.3
Due to Energy Consumption	-1.3	25.8	6.2	74.5
dPS_{PA}, Change in Producer Surplus	98.9	-118.1	-161.4	-712.0
From Generation added by 2021	-57.0	-535.7	-299.9	-2,776.1
From Generation added from 2022 to 2029	155.8	417.7	159.2	2,084.7
From Generation added in 2030	0.0	0.0	-20.7	-20.7
dK_{PA}, In New Capacity	-121.7	-13.1	18.8	-243.9
dW^e_{PA}, In Permit Market	43.8	80.7	142.5	800.6
dCP_{PA}, Change in Cost of Permits Bought	-75.4	-43.1	11.4	-365.6
dVP_{PA}, Change in Value of Permits Sold	119.3	123.8	131.0	1,166.6

B. Decomposition of Change in Aggregate Surplus within Rest of PJM				
dW_{RPJM}, Change in Aggregate Surplus	17.6	-1.0	7.8	56.0
dW^x_{RPJM}, In Electricity Market	61.5	79.7	150.3	856.6
dCS_{RPJM}, Change in Consumer Surplus	77.6	-15.1	56.0	40.7
Due to Loss	2.3	-1.2	1.9	-3.5
Due to Energy Consumption	75.3	-13.9	54.1	40.7
dPS_{RPJM}, Change in Producer Surplus	-113.5	111.1	106.5	720.8
From Generation added by 2021	-11.1	113.6	-101.7	482.7
From Generation added from 2022 to 2029	-102.4	2.5	198.6	233.4
From Generation added in 2030	0.0	0.0	9.6	9.6
dK_{RPJM}, In New Capacity	97.3	-16.3	-12.3	95.1
dW^e_{RPJM}, In Permit Market	-43.8	-80.7	-142.5	-800.6
dCP_{RPJM}, Change in Cost of Permits Bought	312.6	132.9	122.1	1,503.1
dVP_{RPJM}, Change in Value of Permits Sold	-356.4	-213.6	-264.5	-2,303.8

C. Decomposition of Change in Aggregate Surplus within PJM				
dW, Change in PJM Aggregate Surplus	11.1	14.7	48.6	172.9
dW_{PA}, In Pennsylvania	19.4	-23.9	6.2	-79.1
dW_{RPJM}, In Rest of PJM	17.6	-1.0	7.8	56.0
dCR, Change in Congestion Rent	-26.0	39.6	34.7	195.9
dCR_{PA}, In Pennsylvania	5.0	26.8	16.7	167.8
dCR_{RPJM}, In Rest of PJM	3.8	8.1	4.3	55.6
dCR_{Other}, In Cross Border Links	-34.8	4.7	13.7	-27.6
dW^x, In PJM Electricity Market	37.1	-24.8	13.9	-23.1
dW^e, In PJM Permit Market	0.0	0.0	0.0	0.0
$dW_{PA} + dCR_{PA}$	24.5	3.0	22.8	88.9
$dW_{RPJM} + dCR_{RPJM} + dCR_{Other}$	-13.3	11.8	25.8	84.2
Ratio	-1.8	0.3	0.9	1.06
$dW_{PA} + dCR_{PA} + dCR_{Other}$	-10.3	7.6	36.5	61.1
$dW_{RPJM} + dCR_{RPJM}$	21.5	7.1	12.1	111.7
Ratio	-0.5	1.1	3.0	0.55

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Appendix

Analytical Derivations

A. Welfare Change Formulas with Respect to Trading Regime

Derivation of Utility Maximization Problem: A representative consumer maximizes utility with respect to budget constraint:

$$\max_{x_i, y_i} U_i(x_i, y_i) = u_i(x_i) + y_i$$

$$\text{s.t:} \qquad p_i x_i + y_i = L_i + \pi_i\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) + \lambda_i \bar{e}_i$$

$$\Leftrightarrow \quad \max_{x_i, y_i} U_i(x_i, y_i) = u_i(x_i) + L_i + \pi_i\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) + \lambda_i \bar{e}_i - p_i x_i$$

The derivation of this problem with respect to quantity demanded x_i yields:

$$\boxed{u_i'\left(x_i\right) = p_i \quad \forall i}$$

The indirect utility is, therefore, given as:

$$V_i\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) = u_i\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) + L_i + \pi_i\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) + \lambda_i \bar{e}_i - p_i x_i\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right)$$

Derivation of Profit Maximization Problem: A representative producer maximizes profit with respect to constraints transmission, RPS and permit demand constraints:

$$
\begin{aligned}
\max_{X_i^{er},X_i^{ef},X_i^{nr},X_i^{nf},K_i^{nr},K_i^{nf},f_{ii'}} \pi_i = \quad & p_i\left[X_i^{er}+X_i^{ef}+X_i^{nr}+X_i^{nf}-f_{ii'}\right]+p_{i'}f_{ii'} \\
& -\lambda_i\left[\phi_i^{ef}X_i^{ef}+\phi_i^{er}X_i^{er}\right] \\
& -\left[g_i^{er}\left(X_i^{er}\right)+g_i^{ef}\left(X_i^{ef}\right)+g_i^{nr}\left(X_i^{nr}\right)+g_i^{nf}\left(X_i^{nf}\right)\right] \\
& -\left[\gamma_i^{nr}K_i^{nr}+\gamma_i^{nf}K_i^{nf}\right]
\end{aligned}
$$

$$
\begin{aligned}
\text{s.t:} \quad & -\bar{f}\leq f_{ii'}\leq\bar{f} && \left(\mu_i^1\,\&\,\mu_i^2\right) \\
& X_i^{nr}\leq K_i^{nr} && \left(\mu_i^3\right) \\
& X_i^{nf}\leq K_i^{nf} && \left(\mu_i^4\right) \\
& \frac{X_i^{er}+X_i^{nf}}{X_i^{er}+X_i^{ef}+X_i^{nr}+X_i^{nf}}\geq\bar{r}_i && \left(\theta_i\right)
\end{aligned}
$$

The Lagrangian of this problem yields:

$$
\begin{aligned}
\mathcal{L}= \quad & p_i\left[X_i^{er}+X_i^{ef}+X_i^{nr}+X_i^{nf}-f_{ii'}\right]+p_{i'}f_{ii'}-\gamma_i^{nr}K_i^{nr}-\gamma_i^{nf}K_i^{nf} \\
& -g_i^{er}\left(X_i^{er}\right)-g_i^{ef}\left(X_i^{ef}\right)-g_i^{nr}\left(X_i^{nr}\right)-g_i^{nf}\left(X_i^{nf}\right)-\lambda_i\left[\phi_i^{ef}X_i^{ef}+\phi_i^{er}X_i^{er}\right] \\
& -\mu_i^3\left[X_i^{nr}-K_i^{nr}\right]-\mu_i^4\left[X_i^{nf}-K_i^{nf}\right]-\mu_i^1\left(-f_{ii'}-\bar{f}\right)-\mu_i^2\left(f_{ii'}-\bar{f}\right) \\
& -\theta_i\left[\bar{r}_i\left(X_i^{ef}+X_i^{nf}\right)+\left(\bar{r}_i-1\right)\left(X_i^{er}+X_i^{nr}\right)\right]
\end{aligned}
$$

The derivation of this problem with respect to existing quantity supplied X_i^{ef} and X_i^{er} yields:

$$
\boxed{g_i^{ef\prime}\left(X_i^{ef}\right)=p_i-\lambda_i\phi_i^{ef}-\theta_i\bar{r}_i\quad\forall i}
$$

$$
\boxed{g_i^{er\prime}\left(X_i^{er}\right)=p_i-\lambda_i\phi_i^{er}-\theta_i\left(\bar{r}_i-1\right)\quad\forall i}
$$

The derivation of this problem with respect to quantity supplied X_i^{nf}, X_i^{nr} yields:

$$\boxed{g_i^{nf\prime}\left(X_i^{nf}\right) = p_i - \theta_i \bar{r}_i - \mu_i^3 \quad \forall i}$$
$$\boxed{g_i^{nr\prime}\left(X_i^{nr}\right) = p_i - \theta_i\left(\bar{r}_i - 1\right) - \mu_i^4 \quad \forall i}$$

The derivation of the RPS constraints with respect to permit price λ_i yields:

$$\left(\frac{dX_i^{ef}}{d\lambda_i} + \frac{dX_i^{nf}}{d\lambda_i}\right)\bar{r}_i + \left(\frac{dX_i^{er}}{d\lambda_i} + \frac{dX_i^{nr}}{d\lambda_i}\right)\left(\bar{r}_i - 1\right) \leq 0$$

The profit is, therefore, given as:

$$\begin{aligned}
\pi_i\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) =& p_i\left[\sum_j X_i^j\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) - f_{ii'}\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right)\right] + p_{i'} f_{ii'}\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) \\
& - \lambda_i\left[\phi_i^{er} X_i^{er}\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) + \phi_i^{ef} X_i^{ef}\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right)\right] - \sum_j g_i^j\left[X_i^j\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right)\right] \\
& - \left[\gamma_i^{nr} K_i^{nr}\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right) + \gamma_i^{nf} K_i^{nf}\left(\boldsymbol{p}, \boldsymbol{\lambda}, \bar{\boldsymbol{r}}\right)\right]
\end{aligned}$$

in which, $j = \{er, ef, nr, nf\}$, the set of all EGUs.

Formulas of Welfare Changes Total welfare in state i equals the sum of producer's profit and consumer utility in state i. Thus, the change in welfare with respect to trading regime is:

$$\frac{dW_i}{d\lambda_i} = \frac{dU_i}{d\lambda_i} + \frac{d\pi_i}{d\lambda_i}$$

Change in consumer utility with respect to trading regime:

$$\frac{dU_i}{d\lambda_i} = u_i'\left(x_i\right)\frac{dx_i}{d\lambda_i} + \bar{e}_i - \frac{dp_i}{d\lambda_i}x_i - p_i\frac{dx_i}{d\lambda_i}$$

$$\frac{dU_i}{d\lambda_i} = \bar{e}_i - \frac{dp_i}{d\lambda_i}x_i + \underbrace{u_i'\left(x_i\right)\frac{dx_i}{d\lambda_i} - p_i\frac{dx_i}{d\lambda_i}}_{=0}$$

Finally:

$$\boxed{\frac{dU_i}{d\lambda_i} = \quad \bar{e}_i - \frac{dp_i}{d\lambda_i}x_i}$$

Change in profit with respect to trading regime:

$$\begin{aligned}
\frac{d\pi_i}{d\lambda_i} = \quad & \frac{dp_i}{d\lambda_i}\left(X_i^{er} + X_i^{ef} + X_i^{nr} + X_i^{nf} - f_{ii'}\right) + p_i\left(\frac{dX_i^{er}}{d\lambda_i} + \frac{dX_i^{ef}}{d\lambda_i} + \frac{dX_i^{nr}}{d\lambda_i} + \frac{dX_i^{nf}}{d\lambda_i} - \frac{df_{ii'}}{d\lambda_i}\right) \\
& + \frac{dp_{i'}}{d\lambda_i}f_{ii'} + p_{i'}\frac{df_{ii'}}{d\lambda_i} - \phi_i^{er}X_i^{er} - \phi_i^{ef}X_i^{ef} - \lambda_i\phi_i^{er}\frac{dX_i^{er}}{d\lambda_i} - \lambda_i\phi_i^{ef}\frac{dX_i^{er}}{d\lambda_i} \\
& - g_i^{er\prime}(X_i^{er})\frac{dX_i^{er}}{d\lambda_i} - g_i^{ef\prime}(X_i^{ef})\frac{dX_i^{ef}}{d\lambda_i} - g_i^{nr\prime}(X_i^{nr})\frac{dX_i^{nr}}{d\lambda_i} - g_i^{nf\prime}\left(X_i^{nf}\right)\frac{dX_i^{nf}}{d\lambda_i} - \gamma_i^{nr}\frac{dK_i^{nr}}{d\lambda_i} - \gamma_i^{nf}\frac{dK_i^{nf}}{d\lambda_i}
\end{aligned}$$

$$\begin{aligned}
\frac{d\pi_i}{d\lambda_i} = \quad & \frac{dp_i}{d\lambda_i}\left(X_i^{er} + X_i^{ef} + X_i^{nr} + X_i^{nf}\right) + \left(\frac{dp_{i'}}{d\lambda_i} - \frac{dp_i}{d\lambda_i}\right)f_{ii'} + (p_{i'} - p_i)\frac{df_{ii'}}{d\lambda_i} - \phi_i^{er}X_i^{er} - \phi_i^{ef}X_i^{ef} \\
& + \frac{dX_i^{er}}{d\lambda_i}\left(p_i - \lambda_i\phi_i^{er} - g_i^{er\prime}(X_i^{er})\right) + \frac{dX_i^{ef}}{d\lambda_i}\left(p_i - \lambda_i\phi_i^{ef} - g_i^{ef\prime}(X_i^{ef})\right) + \frac{dX_i^{nr}}{d\lambda_i}\left(p_i - g_i^{nr\prime}(X_i^{nr})\right) \\
& + \frac{dX_i^{nf}}{d\lambda_i}\left(p_i - g_i^{nf\prime}(X_i^{nf})\right) - \gamma_i^{nr}\frac{dK_i^{nr}}{d\lambda_i} - \gamma_i^{nf}\frac{dK_i^{nf}}{d\lambda_i}
\end{aligned}$$

$$\begin{aligned}
\frac{d\pi_i}{d\lambda_i} = \quad & \frac{dp_i}{d\lambda_i}\left(X_i^{er} + X_i^{ef} + X_i^{nr} + X_i^{nf}\right) + \left(\frac{dp_{i'}}{d\lambda_i} - \frac{dp_i}{d\lambda_i}\right)f_{ii'} + (p_{i'} - p_i)\frac{df_{ii'}}{d\lambda_i} - e_i \\
& + \theta_i\left[\frac{dX_i^{ef}}{d\lambda_i}\bar{r}_i + \frac{dX_i^{er}}{d\lambda_i}(\bar{r}_i - 1) + \frac{dX_i^{nf}}{d\lambda_i}\bar{r}_i + \frac{dX_i^{nr}}{d\lambda_i}(\bar{r}_i - 1)\right] - \gamma_i^{nr}\frac{dK_i^{nr}}{d\lambda_i} - \gamma_i^{nf}\frac{dK_i^{nf}}{d\lambda_i}
\end{aligned}$$

$$\begin{aligned}
\frac{d\pi_i}{d\lambda_i} = \quad & \frac{dp_i}{d\lambda_i}\left(X_i^{er} + X_i^{ef} + X_i^{nr} + X_i^{nf}\right) + \left(\frac{dp_{i'}}{d\lambda_i} - \frac{dp_i}{d\lambda_i}\right)f_{ii'} + (p_{i'} - p_i)\frac{df_{ii'}}{d\lambda_i} - e_i \\
& \underbrace{+ \theta_i\left[\left(\frac{dX_i^{ef}}{d\lambda_i} + \frac{dX_i^{nf}}{d\lambda_i}\right)\bar{r}_i + \left(\frac{dX_i^{er}}{d\lambda_i} + \frac{dX_i^{nr}}{d\lambda_i}\right)(\bar{r}_i - 1)\right]}_{=0^1} - \gamma_i^{nr}\frac{dK_i^{nr}}{d\lambda_i} - \gamma_i^{nf}\frac{dK_i^{nf}}{d\lambda_i}
\end{aligned}$$

Finally:

$$\boxed{\frac{d\pi_i}{d\lambda_i} = \frac{dp_i}{d\lambda_i}\left(X_i^{er}+X_i^{ef}+X_i^{nr}+X_i^{nf}\right)+\left(\frac{dp_{i'}}{d\lambda_i}-\frac{dp_i}{d\lambda_i}\right)f_{ii'}+\left(p_{i'}-p_i\right)\frac{df_{ii'}}{d\lambda_i}-e_i-\gamma_i^{nr}\frac{dK_i^{nr}}{d\lambda_i}-\gamma_i^{nf}\frac{dK_i^{nf}}{d\lambda_i}}$$

Change in welfare with respect to trading regime:

$$\frac{dW_i}{d\lambda_i} = \frac{dU_i}{d\lambda_i}+\frac{d\pi_i}{d\lambda_i}$$

$$\begin{aligned}\frac{dW_i}{d\lambda_i} = {} & \bar{e}_i-\frac{dp_i}{d\lambda_i}x_i+\frac{dp_i}{d\lambda_i}\left(X_i^{er}+X_i^{ef}+X_i^{nr}+X_i^{nf}\right)+\left(\frac{dp_{i'}}{d\lambda_i}-\frac{dp_i}{d\lambda_i}\right)f_{ii'}+\left(p_{i'}-p_i\right)\frac{df_{ii'}}{d\lambda_i}-e_i \\ & -\gamma_i^{nr}\frac{dK_i^{nr}}{d\lambda_i}-\gamma_i^{nf}\frac{dK_i^{nf}}{d\lambda_i}\end{aligned}$$

$$\frac{dW_i}{d\lambda_i} = \frac{dp_i}{d\lambda_i}f_{ii'}+\left(\frac{dp_{i'}}{d\lambda_i}-\frac{dp_i}{d\lambda_i}\right)f_{ii'}+\left(p_{i'}-p_i\right)\frac{df_{ii'}}{d\lambda_i}+\left(\bar{e}_i-e_i\right)-\gamma_i^{nr}\frac{dK_i^{nr}}{d\lambda_i}-\gamma_i^{nf}\frac{dK_i^{nf}}{d\lambda_i}$$

$$\frac{dW_i}{d\lambda_i} = \frac{dp_{i'}}{d\lambda_i}f_{ii'}+\left(p_{i'}-p_i\right)\frac{df_{ii'}}{d\lambda_i}+\left(\bar{e}_i-e_i\right)-\left(\gamma_i^{nr}\frac{dK_i^{nr}}{d\lambda_i}+\gamma_i^{nf}\frac{dK_i^{nf}}{d\lambda_i}\right)$$

Therefore, the change in welfare in state i from moving from intrastate permit trading to interstate permit trading is:

$$\boxed{dW_i = f_{ii'}dp_{i'}+\left(p_{i'}-p_i\right)df_{ii'}+\left(\bar{e}_i-e_i\right)d\lambda_i-\left(\gamma_i^{nr}dK_i^{nr}+\gamma_i^{nf}dK_i^{nf}\right)}$$

The total change in welfare across states from moving from intrastate permit trading to interstate trading is:

$$\boxed{dW = \sum_i f_{ii'}dp_{i'}+\sum_i\left(p_{i'}-p_i\right)df_{ii'}+\sum_i\left(\bar{e}_i-e_i\right)d\lambda_i-\sum_i\left(\gamma_i^{nr}dK_i^{nr}+\gamma_i^{nf}dK_i^{nf}\right)}$$

Model Calibration

1. Establishing PJM Regions

PJM load zones are grouped into five regions based on similarity in real-time (RT) hourly Locational Marginal Prices (LMPs) and geographical proximity in Pennsylvania (PA) and Rest of PJM (RPJM). The five regions are: East PA, which includes Metropolitan Edison Company, PPL Electric Utilities Corporation, and PECO Energy Company; West PA, which includes West Penn Power (PA part of Allegheny Power), the PA part of American Transmission Systems Inc, Duquesne Light Company and Pennsylvania Electric Company; East RPJM, which includes Atlantic City Electric Company, Jersey Central Power and Light Company, Public Service Electric and Gas Company, Delmarva Power and Light Company and Rockland Electric Company; West RPJM, which includes the non-PA part of Allegheny Power, American Electric Power Company, the OH part of American Transmission Systems Inc, Commonwealth Edison Company, Duke Energy Ohio and Kentucky, East Kentucky Power Cooperative Inc, and The Dayton Power and Light Company and Central RPJM, which includes Baltimore, Dominion and Potomac. The five figures below show RT hourly LMPs of these load zones in the PJM regions they are grouped into, using a curve smoothing bandwidth of 0.8.

Figure **??** shows sorted RT LMPs of the three zones in East PA from the lowest peak demand hour to the highest peak demand hour. LMP in the lowest peak hour is as low as approximately $5 and LMP in the highest peak hour is as high as more than $50. LMP in a median load segment is around $22.

Similarly, figure **??** shows sorted RT LMPs of the four zones in West PA. LMP in West PA in the lowest peak hour is as low as approximately $15 and LMP in the highest peak hour is as high as more than $50. LMP in a median load segment is around $27. Overall, West PA observes higher LMPs than East PA in 2016.

Figure 1: RT LMPs in East PA in 2016

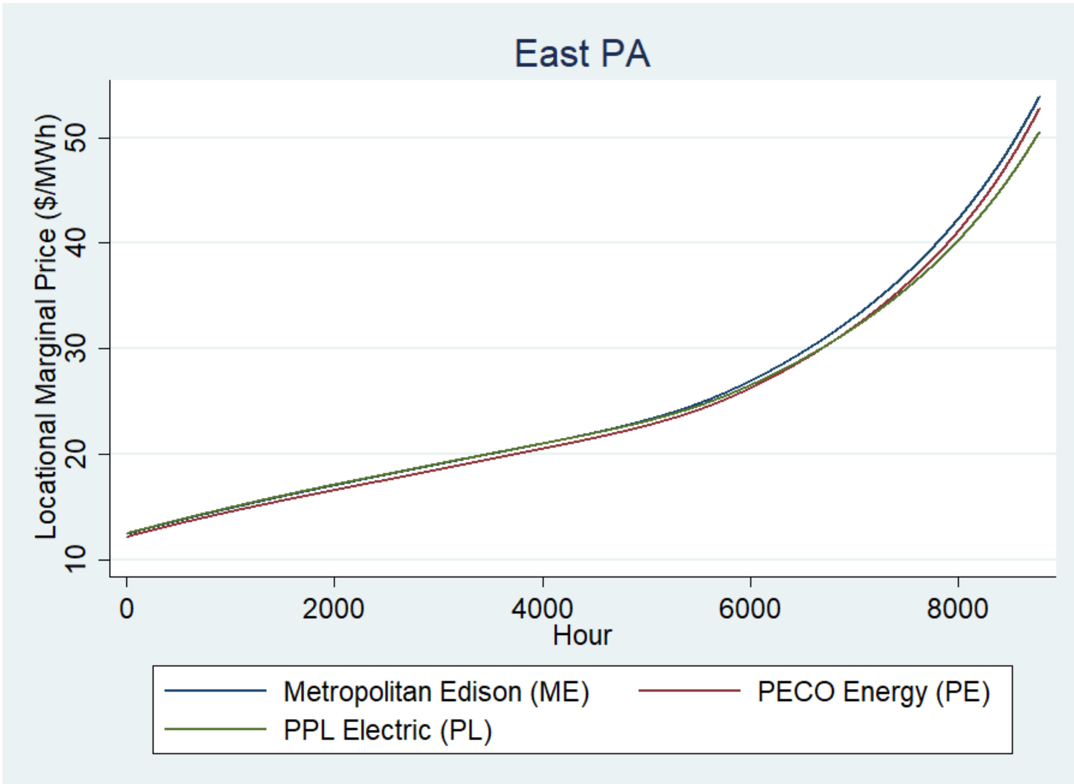


Figure 2: RT LMPs in West PA in 2016

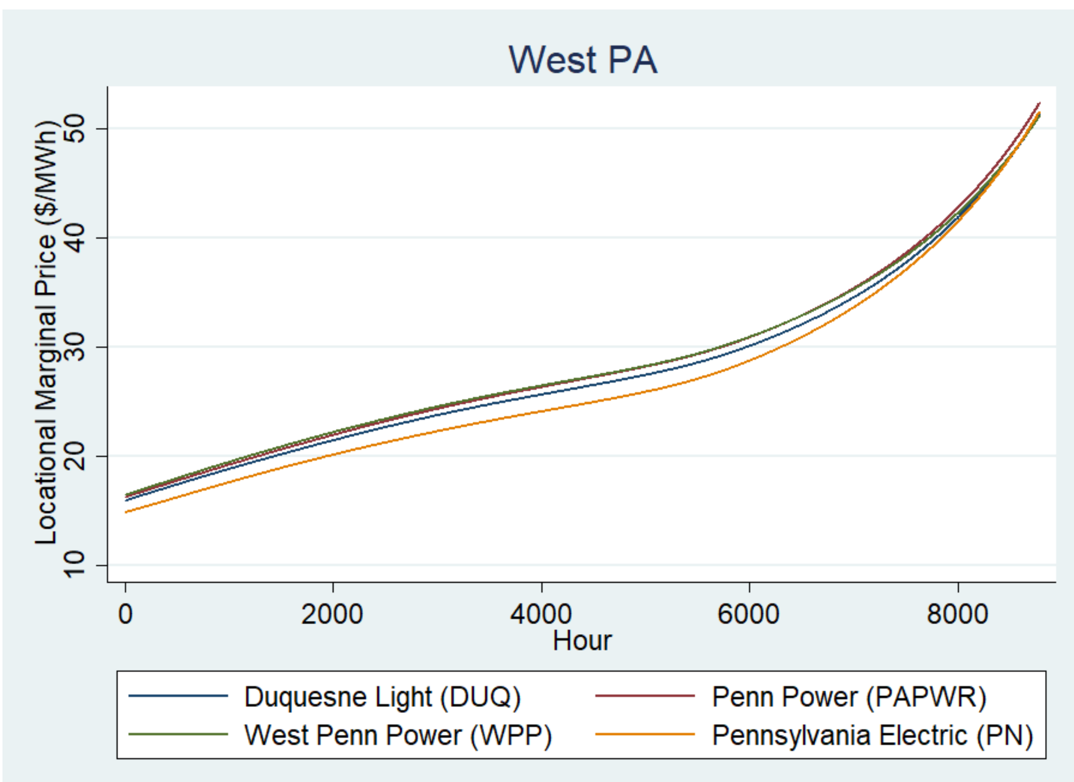


Figure ?? shows sorted RT LMPs of the five zones in East RPJM. LMP in this PJM region in the lowest peak hour is as low as approximately $11 and LMP in the highest peak hour is as high as more than $60 for DPL zone and more than $50 for the other zones. LMP in a median load segment is around $22.

Similarly, figure ?? shows sorted RT LMPs of the seven zones in West RPJM. LMP in this PJM region in the lowest peak hour is as low as approximately more than $15 and LMP in the highest peak hour is as high as approximately $55 in the highest LMP zone and $43 the lowest LMP zone. LMPs in the 2,000 highest demand hours in West RPJM are spread out. LMP in this region in a median load segment is around $27.

The last PJM region is Central RPJM, which is shown in figure ??. As we can see, LMPs in this region are the most spread out, with the highest LMP of $69 in the peak hour and the lowest LMP of approximately $18 in the lowest demand hour. LMP in this region in a median load segment is above $30. Overall, Central RPJM observes higher LMPs than West RPJM, which in turns observes higher LMPs than East RPJM in 2016.

Figure 3: RT LMPs in East RPJM in 2016

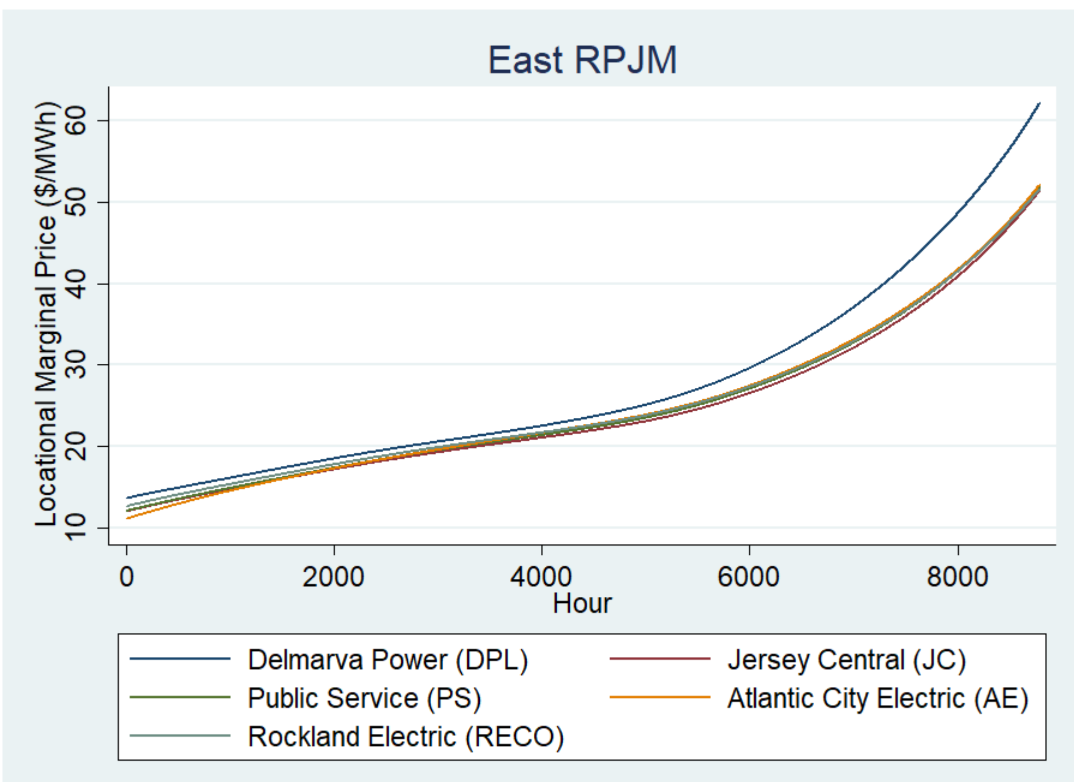


Figure 4: RT LMPs in West RPJM in 2016

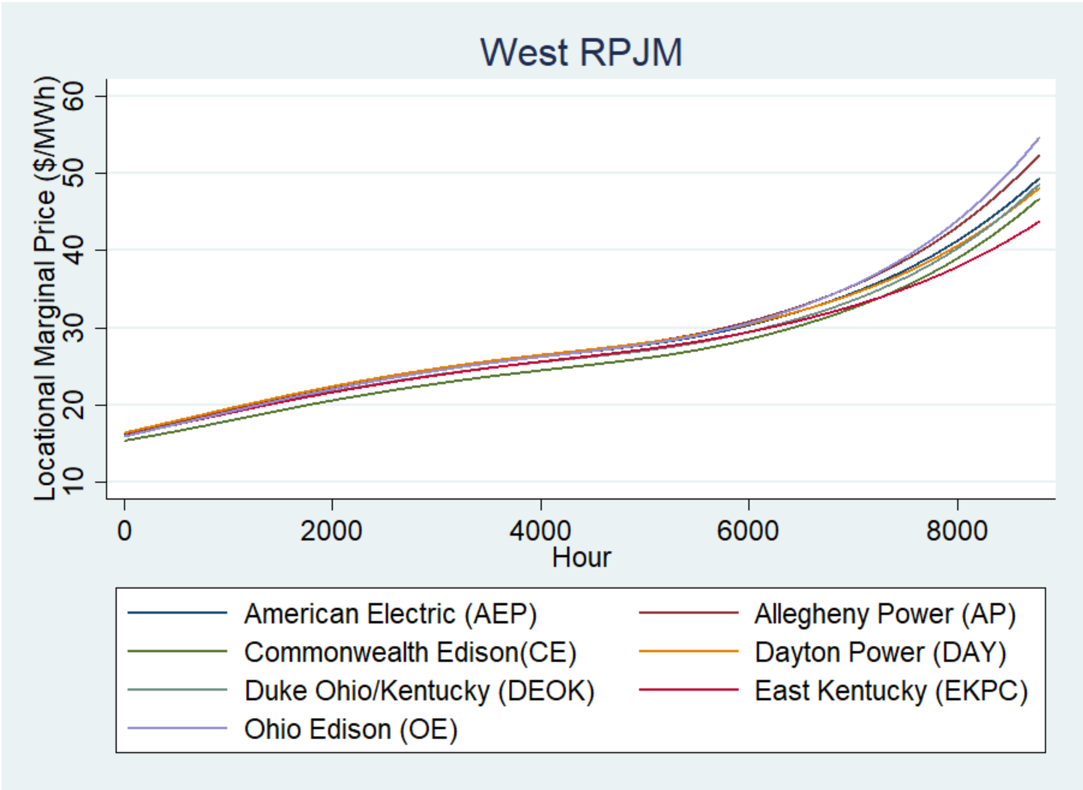


Figure 5: RT LMPs in Central RPJM in 2016

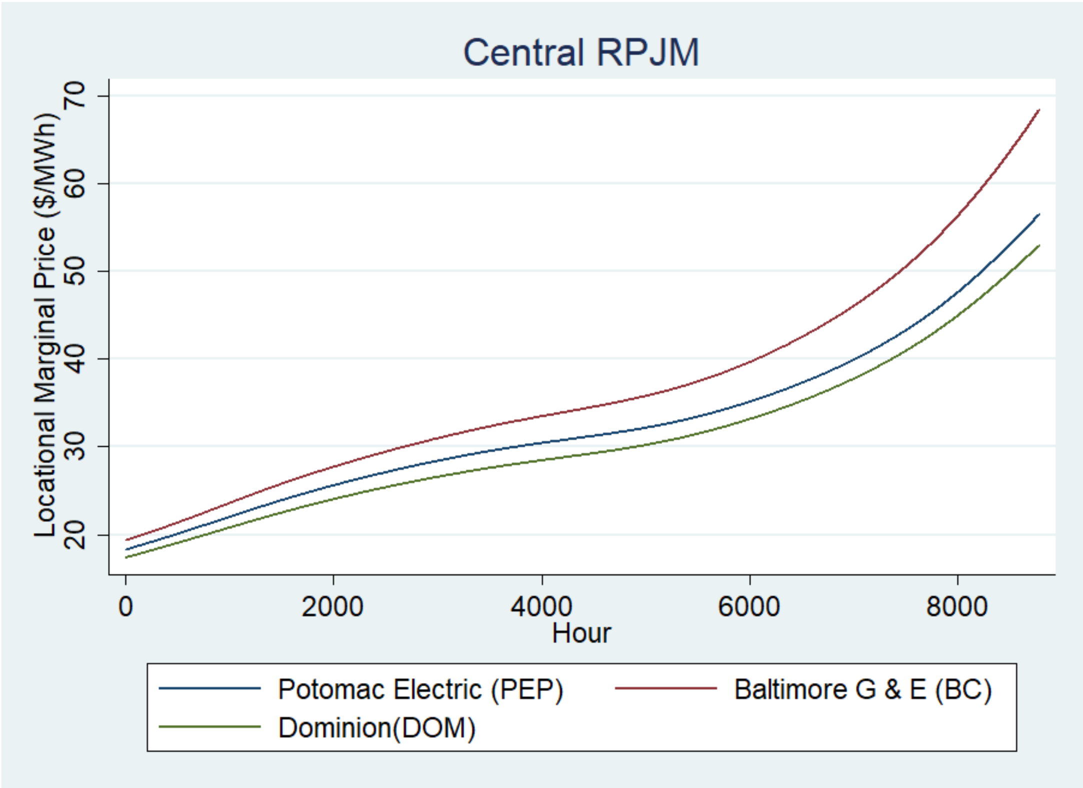
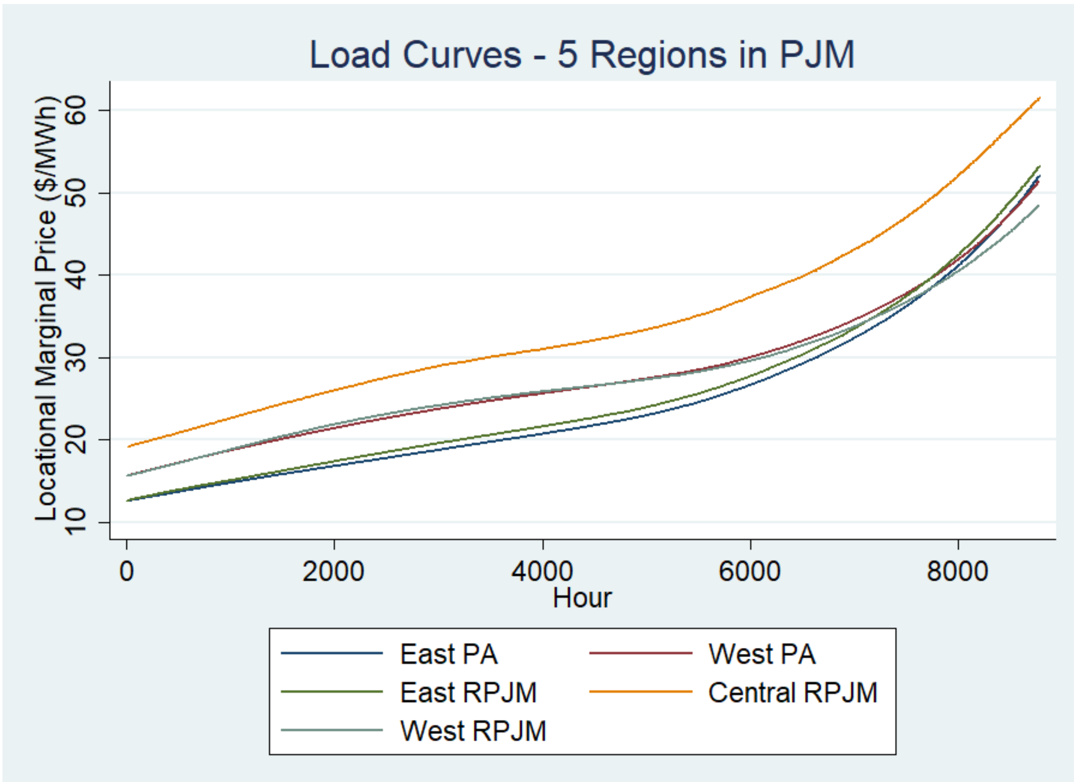


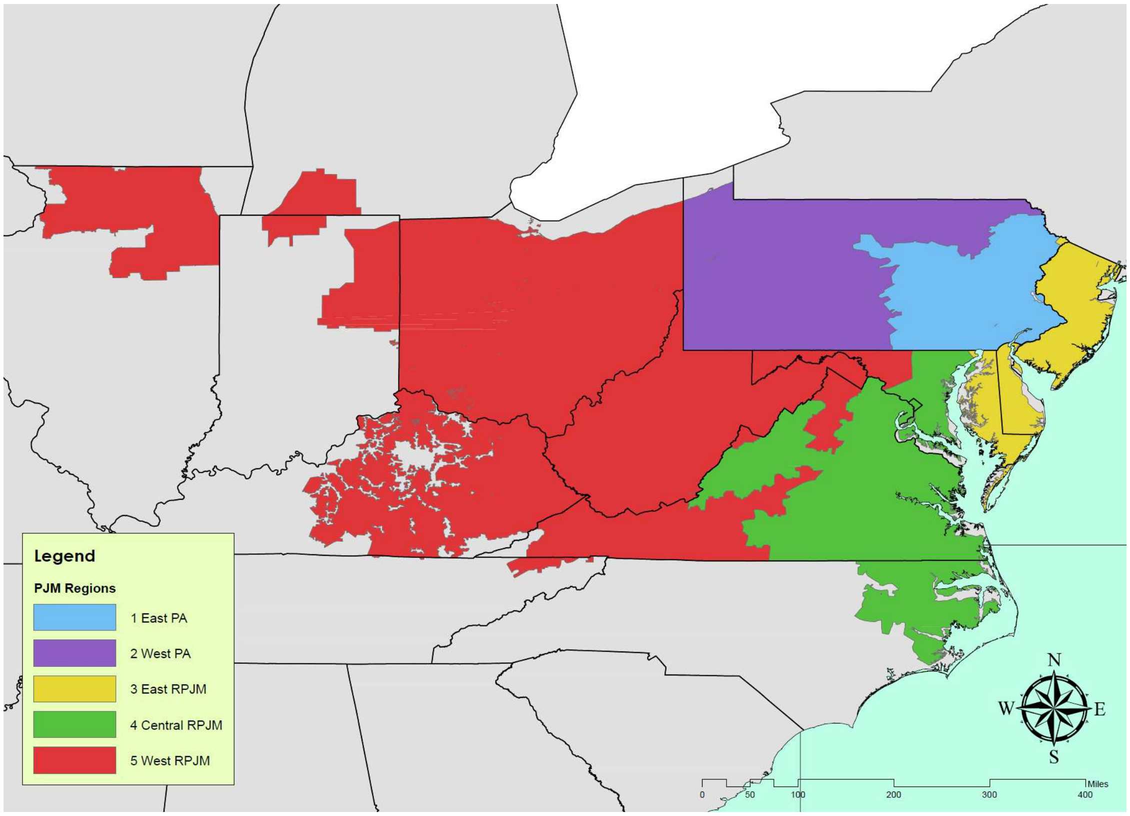
Figure 6 shows the sorted RT LMPs of the established five PJM regions from the lowest peak demand hour to the highest peak demand hour. Central RPJM has the highest over LMPs, seconded by West RPJM and West PA, while East PA and East RPJM have similarly overall the lowest LMPs.

Figure 6: RT LMPs in Five Regions of PJM in 2016



The map of PJM with the five regions detailed above is shown in figure **??**. In general, eastern part of PJM observe lower LMPs compared to the rest of PJM and overall is the exporter of electricity. The map also shows the five aggregated transmission lines among these five regions: Line 1 connects East PA and West PA, line 2 connects East PA and East RPJM, line 3 connects East PA and Central RPJM, line 4 connects West PA and West RPJM and line 5 connects Central RPJM to West RPJM. There are no direct lines between East PA and West RPJM, nor West PA and East RPJM, nor West PA and Central RPJM, nor East RPJM to Central RPJM, nor East RPJM to West RPJM. Details on how these aggregate transmission lines are established are in section 7 (Transmission Network Constraints).

Figure 7: Map of PJM Regions and Aggregate Transmission Lines as of 2016



2. Supply Side

We calibrate the model using observed market data for 2016 (for the no capacity expansion base case) and 2017 (for the base case with capacity expansion). To calibrate the supply side of the market, we use five different datasets: The latest National Electric Energy Data System (NEEDS) dataset version 5.15 (updated in August 2015) (accessed 05/21/2017), the SNL summer capacity dataset (accessed 05/21/2017), the EPA's Emissions & Generation Resource Integrated Database (eGrid 2014) (accessed 06/15/2017), the EPA's Continuous Emission Monitoring System dataset (CEMS) and Form EIA-923, which is a survey form collecting detailed electric power data on electricity generation, fuel consumption, fuel,... from power plants, (Schedules 3A & 5A - generator data including generation, fuel consumption and stocks) (accessed 07/18/2017), all of which are for the PJM control area. The reason we need all five dataset to create a full PJM generation dataset is because each dataset has its own shortcomings: The NEEDs dataset might not have updated with the newly added generators, the SNL dataset does not have information on locations of the generators, eGrid was last updated in 2014 by the time we last accessed it and thus does not have the most up-to-date data on all PJM generators, EIA-923 only includes a subset of PJM generators taken from a randomized procedure, and CEMS only includes generators of bigger size that are dispatched during the year. Our general method to establish a full PJM generator dataset is to first merge the NEEDs dataset and the SNL dataset to get the first version of the final dataset. Second, we manually check the plants which are in counties that we think might not be in PJM and remove them from this final dataset if necessary. Then, EIA 923 form, eGrid and CEMS datasets are used to match the plants in the final dataset to reasonable heat rates, capacities and emission rates.

The final NEEDS dataset that is used here consists of both active plants and retired plants and covers 10 NERC regions that roughly coincide with the PJM control area as of 2016: PJM_AP, PJM_ATSI, PJM_COMD, PJM_DOM, PJM_EMAC, PJM_PENE, PJM_SMAC, PJM_WMAC, PJM_West, and S_C_KY. The NEEDS dataset includes plant names, plant types, unit IDs, oris plant codes (Office of Regulatory Information System codes, which are the unique identifiers assigned to power plants in NEED), geographical locations of the plants at county level, fuel types, plant capacities, heat rates, and plants' available information (online years, retirement years). The SNL dataset includes plant names, plant types, unit IDs, plant capacities, fuel types, net annual CO_2 emissions, net annual generations, fuel costs and variable operation & maintenance costs (VOM costs). The NEEDS dataset is slightly out of date compared to the SNL dataset, so we combined it to the SNL dataset to obtain a final dataset that will be used for our model calibration. The final dataset consists of the active units located in counties of PJM control area that are in both NEEDS and SNL and the active units that are in NEEDS but not in SNL and those that are in SNL but not in NEEDS.

The NEEDS dataset has 3,071 units in total and the SNL dataset has 3,522 units in total. Most of the plant names, plant types, capacities and unit IDs in the two datasets are similar but not quite exactly the same, therefore, to find the matched and unmatched units in both datasets, we have to merge the two datasets multiple times using both regular merge (merge based on perfectly matched plant names, plant types and unit IDs) and probabilistic merge (merge based on similar plant names, plant types and unit IDs). We first find all the one-to-one unit matches, remove them from the

NEEDS and SNL and then find the one-to-many, many-to-one, and many-to-many unit matches from the remaining units in both datasets. These non one-to-one matches occur because in some cases, the NEEDS report aggregate units made up of multiple boilers of the same plant types while the SNL reports each individual boilers. After finding all these matches, the leftover units from both datasets are the unmatched units, of which only those that are active, are included in the final dataset. Detailed processes of the one-to-one units matching and non-one-to-one units matching are described in the following subsections. Table 1 and Table 2 are summaries of our merge results for the NEEDS and the SNL.

a. One-to-One Matching NEEDS and SNL Units

To find one-to-one unit matches between NEEDS and SNL, we merge the two datasets four times.

First, we match the units that have exactly the same plant names, plant types and unit IDs in NEEDS and SNL. This merge results in 456 one-to-one matched units between the two datasets. These matched units are set aside and removed from the original NEEDS and SNL datasets, leaving the remaining NEEDS dataset to now have 2,615 units and the SNL dataset to now have 3,066 units.

Second, for the remaining units in the two datasets, we use a probabilistic merge (reclink2) in Stata, again using plant names, plant types and unit IDs with the additional requirement that unit IDs be matched exactly. The probabilistic merge gives us a match score for each unit in a range from 0 (not a match at all) to 1 (a perfect match). A match score of 0.9 or above provides a pretty good one-to-one match between the two datasets. We hand check those with a match score of less than 0.9 to filter out the wrong matches.

To do hand-checking, we consider a unit in NEEDS a match for a unit in SNL if they have similar plant names, the exact same unit ID, similar plant type, similar fuel type and similar capacity. For example, unit "Homer City" in SNL with plant type of Steam Turbine, unit ID of 2, fuel type of Coal and capacity of 617.5 MW is a one-to-one match for unit "Homer City Station" in NEEDS with plant type of Coal Steam, unit ID of 2, fuel type of Bituminous and capacity of 614 MW. This provides another batch of 1,577 one-to-one matched units. We again remove these additional one-to-one matched units from the two datasets.

Third, for the remaining units from the two datasets (1,038 units from NEEDS and 1,489 units from SNL), we again use reclink2, this time only using plant names and unit IDs as identifiers since the plant capacities for this subset of units maybe different. We notice several instances where an unit in SNL matches with more than one unit in NEEDS or several units in SNL match with one unit in NEEDS or several units in SNL match with several units in NEEDS. For example, unit "Covanta Plymouth (Montenay Montgomery)" in SNL with fuel type of Biomass, unit ID of 1 and capacity of 28 MW is a match for two units in NEEDS combined, which are "Montenay Montgomery LP" unit ID of 1 and unit ID of 2 with fuel type of Municipal Solid Waste (MSW), capacity of 14 MW each. But these types of matching units are not one-to-one matches and thus we rule them out for now and will only match them in the next subsection. We also relax the requirement of exactly matched unit IDs since the two datasets can have different unit IDs to mean the same units; for example, unit 1 of the same plant in the NEEDS dataset has unit ID of GEN1 (generator 1) but in the SNL dataset has unit ID of BOIL1 (boiler 1). They, however, both mean the same unit (unit 1). Hand-checking and correcting the match results from this round of merge, we have another 263 one-to-one matched units, bringing the total one-to-one matched units so far to 2,296 units.

Last, for the remaining units in the two datasets (775 units from NEEDS and 1,226 units from SNL), we use reclink2 once more, this time only using plant names. Hand-checking and correcting the match results again, we end up with another 147 one-to-one matched units, bringing the total one-to-one matched units so far to 2,443 units. The breakdown of these units and their total capacities are shown in Table 1 and Table 2, rows 2-6. Of these 2,443 units, 2,367 units are active in both datasets, 36 units are only active in NEEDs, 27 units are only active in the SNL and 13 units are inactive in both datasets. We only include those units that are active in SNL in the final dataset, which means only 2,394 (2,367+27) are included in the final dataset out of the 2,443 one-to-one matched units.

After completing the one-to-one units matching, we have 628 units in the NEEDS that cannot be matched one-to-one to the units in SNL and 1,109 units in SNL that cannot be matched one-to-one to units in the NEEDS. These two sets of units are next to be matched together either one-to-many, many-to-one or many-to-many.

b. Non-One-to-One Matching NEEDS and SNL Units

We can also match several units in NEEDS to one unit in SNL, or one unit in NEEDS to several units in SNL, or many units in NEEDS to many units in SNL, as long as these matching units have the same plant names in both datasets. To do this, we find plants in NEEDS and SNL that have the same or similar plant names, same or similar plant types and the same or close to the same total capacity across all the units in the plants of the same fuel types. For example, two coal units in SNL, Joliet 29 unit 7 and unit 8 with capacity of 518 MW each, combined together is a many-to-many match for four bituminous units in NEEDS, Joliet 29 units 71, 72, 81, 82 with capacity of 259 MW each. We find 66 SNL units that can be matched to 118 NEEDS units that can be collapsed down to just 41 one-to-one common plants or common sub-plants of the same fuel types between the two datasets. The breakdown of these units and their total capacities are shown in Table 1 and Table 2, rows 7-11. Of these 41 common plants, 40 plants are active in both datasets, corresponding to 113 units in the NEEDS and 65 units in the SNL, 1 plant is active in NEEDS but inactive in the SNL, corresponding to 5 units in the NEEDS and 1 unit in the SNL. There is no units inactive in the NEEDS but active in SNL and no units inactive in both datasets. We again only include those units that are active in SNL in the final dataset, which means only 65 additional units are included in the final dataset out of the 66 one-to-one matched units. Note that we only include the units from one dataset (SNL) to avoid double counting. We choose the SNL because random unit checks online show the SNL to have more accurate capacities.

We now have 2,509 units in SNL matching with 2,561 units in NEEDS. Removing these unit matches from the original NEEDS and SNL datasets, we end up with 510 unmatched units in NEEDS (Table 2, row 12) (of which 240 units are retired) and 1,013 unmatched units in SNL (of which 23 units are retired) (Table 2, rows 12-14).

c. Checking Unmatched NEEDS and SNL Units

After matching is completed, there remain 270 active units in NEEDS that cannot be matched to the SNL. Since the NEEDS is slightly outdated compared to the SNL, it is possible some of the

270 units are already retired. We search each of these units on the web to remove those units that are no longer available as of 2016. Of these 270 units, we find 34 units are actually retired, closed, withdrawn, demolished, decommissioned, shuttered, forced to stop due to regulatory violations, or not yet operating in 2016, leaving us with only 236 active unmatched units in NEEDS. Of these 236 units, 53 are believed to be aggregated units over small capacity units of the same fuel types, regions and states.

We believe these 53 units are disaggregated in the SNL dataset and thus they are not included in the final dataset to avoid double-counting. Of the 183 remaining units, 62 are believed to not be actually in PJM since the 10 PJM NERC regions do not exactly match the PJM control area, 2 units had capacity of 0 and did not generate during 2016, 14 are small solar PV units, 24 (most of them are combustion turbine units) are small generators suspected to provide power to local facilities and non-dispatchable by PJM, 21 are small units of less than 3 MW that we cannot find information about operating status or capacities. We exclude these units mentioned above (34+53+62+2+14+24+21=210) from the final dataset. Therefore, only 60 units from the 270 unmatched units in the NEEDS are included in the final dataset (Table 1, row 13). These are the units that are still operating and in PJM control area but are not in the SNL.

For the remaining unmatched units in SNL (1,013 units), we filter out the 23 units that are inactive and hand-check the remaining 990 units to make sure they are indeed in PJM control area. After manually checking these units, we only keep 576 units that we believe to belong in PJM and integrate these units into our final dataset (Table 2, row 13).

Table 1: NEEDS Dataset v5.15 Unit Breakdown.

	Number of Units	Capacity of Units	Included in Final Dataset?
Total Number of Units in NEEDS v5.15 Dataset	3,071	219,511	—
One to One Matched with SNL Units	2,443	178,307	—
Active Units In NEEDS and SNL	2,367	173,503	Y
Active in NEEDS and Inactive in SNL	36	2,092	N
Inactive in NEEDS and Active in SNL	27	2,451	Y
Inactive in both NEEDS and SNL	13	261	N
Collapsed to Merge with SNL Units	118	5,308	—
Active Units In NEEDS and SNL	113	5,212	Y
Active in NEEDS and Inactive in SNL	5	96	N
Inactive in NEEDS and Active in SNL	0	0	Y
Inactive in both NEEDS and SNL	0	0	N
Unmatched with SNL	510	35,896	—
Units in PJM and Still Active, but Not in SNL	60	2,470	Y
Units Not Included in Final Dataset	450	33,426	N
Unmatched Aggregate Units	53	1,650	N
Not in PJM	109	11,908	N
In PJM	288	19,868	N
Listed As Inactive by NEEDS	202	16,865	N
Identified As Inactive Via Web Search	25	2,893	N
Otherwise Removed Via Web Search	61	109	N

Table 2: SNL Dataset Unit Breakdown as of 2016.

	Number of Units	Capacity of Units	Included in Final Dataset?
Total Number of Units in SNL Dataset	3,522	193,500	—
One to One Matched with NEEDS Units	2,443	176,635	—
Active Units In NEEDS and SNL	2,367	161,420	Y
Active in NEEDS and Inactive in SNL	36	11,643	N
Inactive in NEEDS and Active in SNL	27	2,266	Y
Inactive in both NEEDS and SNL	13	1,306	N
Collapsed to Merge with NEEDS Units	66	5,138	—
Active Units In NEEDS and SNL	65	4,771	Y
Active in NEEDS and Inactive in SNL	1	367	N
Inactive in NEEDS and Active in SNL	0	0	Y
Inactive in both NEEDS and SNL	0	0	N
Unmatched with NEEDS	1,013	11,727	—
Not in PJM	414	850	N
In PJM	599	10,877	—
Units Included in Final Dataset	576	10,646	Y
Units in SNL, Marked as Inactive	23	231	N

d. Final Dataset Unit Breakdown

After matching the NEEDs and the SNL, we have 3,509 units in total. Table 3 summarizes the breakdown of these units and their total capacity (rows 2-4) as well as the breakdown of fuel types (rows 5-18). This dataset consists of the matched units that are active in both NEEDS and SNL or active in SNL and inactive in NEEDS and the unmatched units in SNL and in NEEDS. As mentioned earlier, of the matched units, 2,394 one-to-one matched units are added to the final dataset and additional 65 non-one-to-one matched units are also added in the final dataset, summing to 2,459 units. Finally, we also include the 60 unmatched units in NEEDS and the 576 unmatched in SNL in the final dataset.

All the units in this dataset make up total capacity of 181,573 MW, of which 168,457 MW are in both NEEDS and SNL, 2,320 MW are in NEEDS only and 10,796 MW are in SNL only. The biggest fuel sources are gas, coal and nuclear, with natural gas units make up 38% of total capacity in PJM, followed by coal units with 32% and nuclear units with 17%. Renewables units and oil units are only 9% and 4% of total PJM capacity, respectively. Biomass, landfill gas, and other fuel types are negligible, making up of only 1% of total capacity in PJM. The final dataset unit breakdown is shown in table 3.

Table 3: Final Dataset Unit Breakdown in 2016.

	Number of Units	Capacity of Units
Total Number of Units in Final Dataset	3,095	181,573
Included in both NEEDS and SNL	2,459	168,457
Included in NEEDS and Not Included in SNL	60	2,470
Not Included in NEEDS and Included in SNL	576	10,646
Natural Gas	836	68,688
Combustion Turbines	597	35,468
Combined Cycle	231	33,190
Other	8	30
Coal	181	57,359
Oil	548	7,023
Nuclear	32	31,244
Biomass & Landfill Gas	765	1,547
Renewables	723	15,479
Solar	340	1,544
Wind	78	5,317
Hydro	305	8,616
Other Fuel	10	233

e. Decide Characteristics of Units

i. Capacity: For those units that are in both the NEEDs and SNL dataset, we use SNL's capacities for them. For the rest of the units, we use capacities from the NEEDs.

ii. Capacity factor/Plant availability: To impute capacity factor for each fuel type, we use three datasets - the Generating Availability Data System (GADS) and EIA's Daily U.S. Nuclear Outage for 2016 and the PJM Generation Outage Daily in 2016. Subtracting the daily nuclear outage from the PJM's total daily outage, we have the daily outage of non-nuclear generators in PJM. Now, we use GADS to find the percentage of outage for each non-nuclear fueltype monthly. Combining the PJM's generation outage data and the GADS together, assuming the same outage for non-nuclear fueltypes in each hour of the same month, we can calculate the percentage of outage for each fueltype in each load segment.

iv. Heat rate and emission rate: To assign heat rate and emission rate to each unit in our final dataset, we merge the final dataset with eGrid, EIA form 923 and CEMS.

Heat rate: To assign heat rate to each unit, we start with the units that are in CEMS because CEMS collects actual emission rates and heat rate reported by units that were dispatched in 2016. First, we use heat rate from CEMS for units in the final dataset that are also in the CEMS in 2016 (374 units). After this step, we have 2,721 units remaining in our final dataset.

The next reliable dataset we use for assigning heat rate to the rest of the units is eGrid. However, there are a few instances when eGrid reports a negative total generation, which coincide with the units that are marked "Data from EIA-923 Generator File overwritten with distributed data from EIA-923 Generation and Fuel", so we flag units in eGrid with this description to be excluded from our calculation of heat rate and emission rate. The average heat rate in eGrid is 13,147.53 with standard deviation of 14,698.89. We use eGrid's average heat rate plus two times its standard deviation (=42,545.31) as eGrid's threshold to assign heat rate from eGrid to the remaining units in our final dataset. This means, we assign the units in the remaining 2,721 units in our final dataset that are also in eGrid their corresponding eGrid's heat-rate as long as the eGrid's heat rate is no more than 42,545.31. After this step, we assign 1,490 units more.

We now have 1,231 units left to assign heat rate to. Next, we use the heat data from SNL to assign to these remaining units. Since the SNL did their own heat rate calculation using EIA 923, in some cases when some units generated a very small amount of energy through the entire year, their estimates of heat rate for these units are so unrealistically high that they had to cap them at 100,000. We believe these estimates are not reasonable and want to exclude these units from our heat rate calculation. To do so, we establish a heat rate threshold for SNL of its average heat rate plus two times its standard deviation (8,914.102+2*8,779.87 = 26,473.842). We assign any remaining units that are in SNL their corresponding SNL heat rate as long as they are no more than 26,473.842. After this step, we assign 801 more units. Thus, now we only have 430 units to assign heat rate to.

To assign these 430 units, we use the EIA 923 form, which reports heat rate for a subset of these units (411) for five years 2012-2016. We calculate the average heat rate across five years and assign them accordingly to these 411 units. The 19 remaining units are assigned heat rates from the NEEDS. Summary of heat rate assignment is shown in the first column of table 4.

Emission rate: To assign emission rate to each unit, we also perform a similar procedure as the procedure to assign heat rate above, but for emission rate. This means, first, we assign the CEMS's emission rates to the units that are in CEMS in the final dataset (374 units). Then we use the eGrid's threshold for emission rate (eGrid's average emission rate plus two times its standard deviation) to make a cut-off and assign emission rate for units in eGrid (1,519). We finally repeat the same same for SNL dataset, after which, all units are assigned emission rates. Summary of emission rate assignment is shown in the second column of table 4.

Table 4: Heat Rate and Emission Rate Assignments to Units in Final Dataset.

Dataset	Number of Units Assigned Heat Rate to	Number of Units Assigned Emission Rate to
Final Dataset	3,095	3,095
CEMS	374	374
eGrid	1,490	1,519
SNL	801	1,201
EIA 923	411	—
NEEDS	19	—

3. Demand Side

For demand side calibration, we use hourly metered load data for all load zones from PJM. We also divide 8784 hours in year 2016 into 96 load segments using three load segment cuts. The first cut is based on seasons: Winter (December 20 to March 21), Spring (March 22 to June 20), Summer (June 21 to September 20) and Fall (September 21 to December 21). We also divide each season into 6 smaller segments based on the descending order of load, following the rule used by the EIA's Integrated Planning Model (IPM) v.5.13: The first segment is the hours with 1% highest loads, the second segment is the next 4%, the third segment is the next 10%, the fourth segment is the next 30%, the fifth segment is the next 30% and finally, the sixth segment is the lowest 25%. After doing this, we now have 24 load segments, based on seasons and loads. Next, we divide each of these 24 load segments into 4 smaller segments based on the descending order of gas price in each segment, with the highest gas-price based load segment is the highest 10% gas price, the second load segment is the next 20% gas price, the third load segment is the next 30% gas price and the final gas-price based load segment in each 24 segment is the lowest 40% gas price. In total, we categorize all 8784 hours in 2016 into $L = 96$ load segments. We do perform the similar processof for 2017 load and LMP data but instead of 8,784 hours, we only have 8,760 hours that make up of the 96 load segments.

Assuming demand elasticity (η^D) of -0.05 (Bushnell et al., 2017), we used the observed load (L_{il}) and LMP in each load segment and PJM region to establish the slopes and intercepts of the quadratic demand functions for five established PJM regions:

$$\text{Demand curve intercepts } c_{il} = \left(\frac{1}{\eta^D}\right) \times \left(\frac{LMP_{il}}{L_{il}}\right)$$
$$\text{Demand curve slopes } n_{il} = \left(1 + \frac{1}{\eta^D}\right) \times LMP_{il}$$

Details on the functional forms and model formulations are detailed in Appendix 2. The functional form assumed for demand is not consequential as our 2016 and 2017 models both predict demand matches actual loads with a high R^2 of 0.998.

The next four figures below show the load curves in each season in 2016. As expected, summer has the highest LMPs, followed by winter. Spring and fall are shoulder months and thus have lower LMPs.

Figure 8: RT LMPs in PJM in Winter 2016

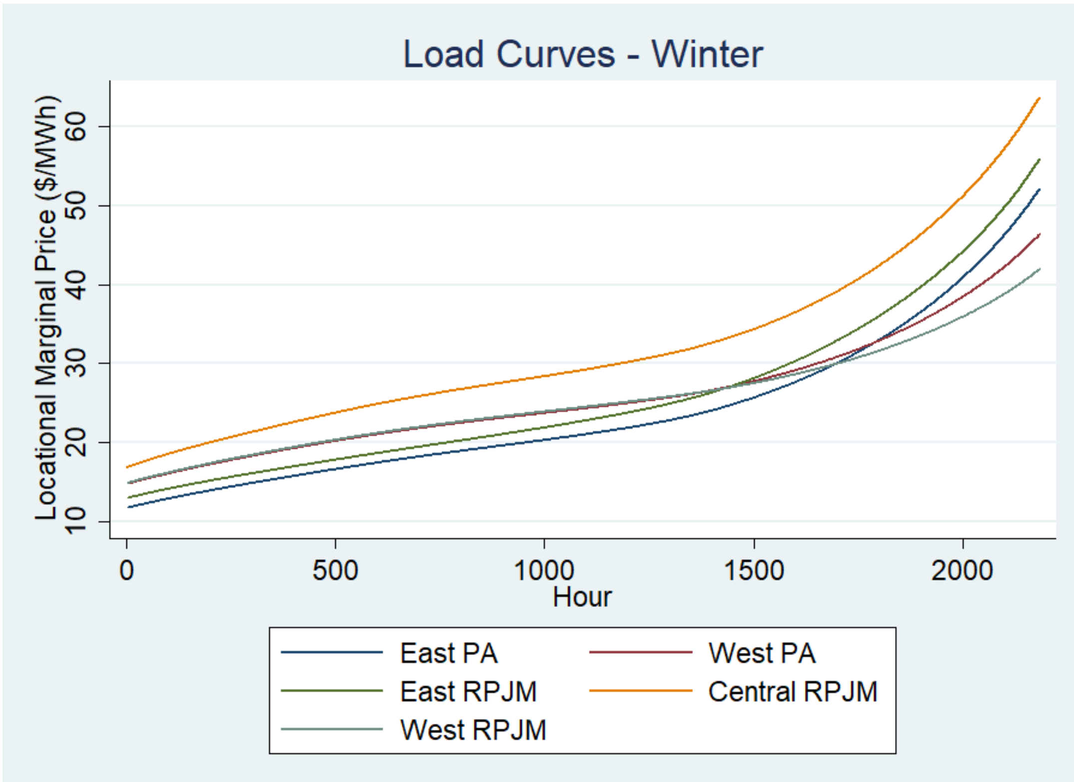


Figure 9: RT LMPs in PJM in Spring 2016

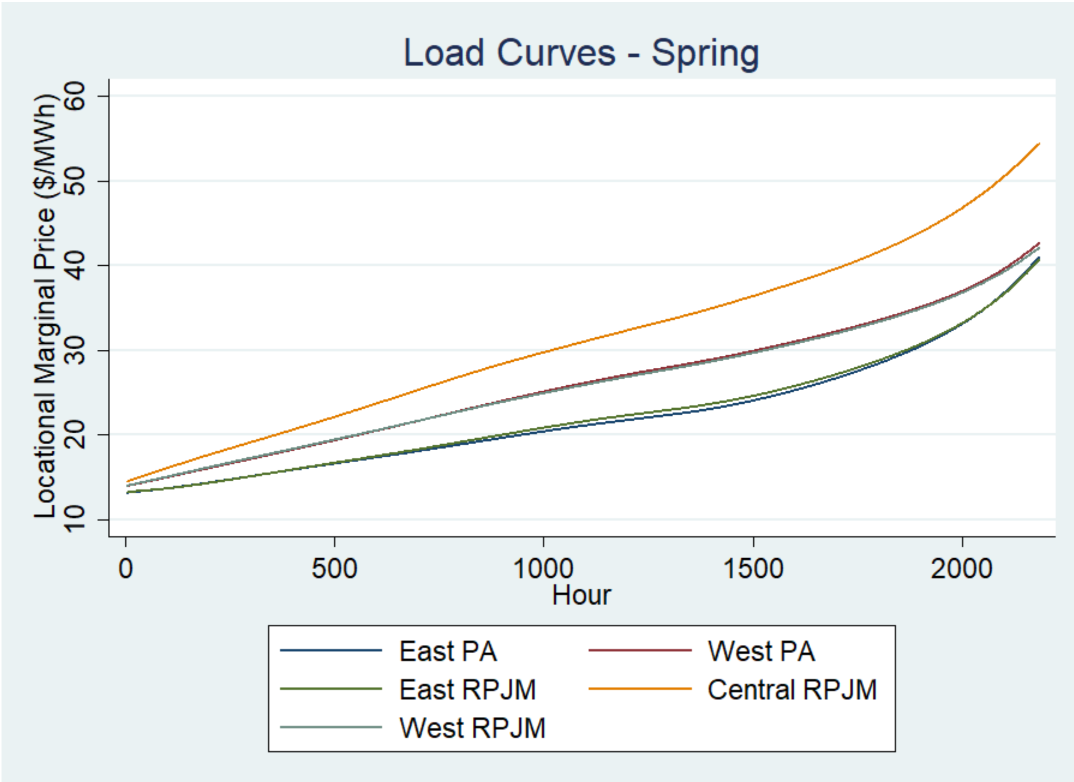


Figure 10: RT LMPs in PJM in Summer 2016

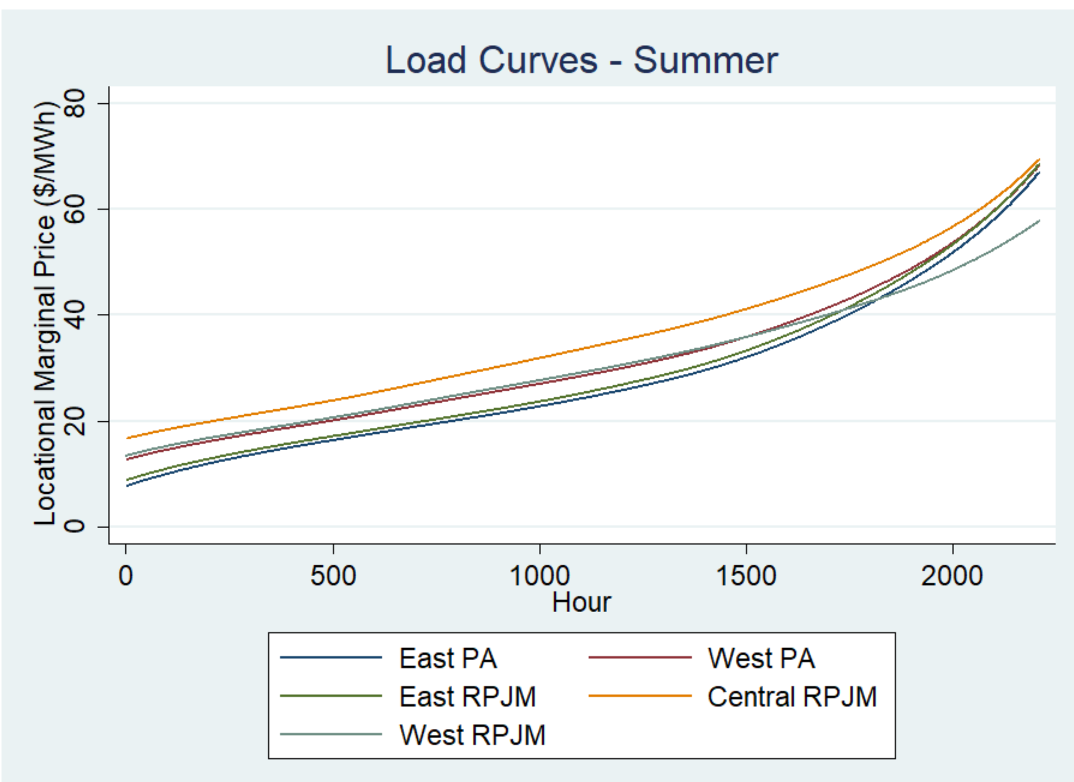
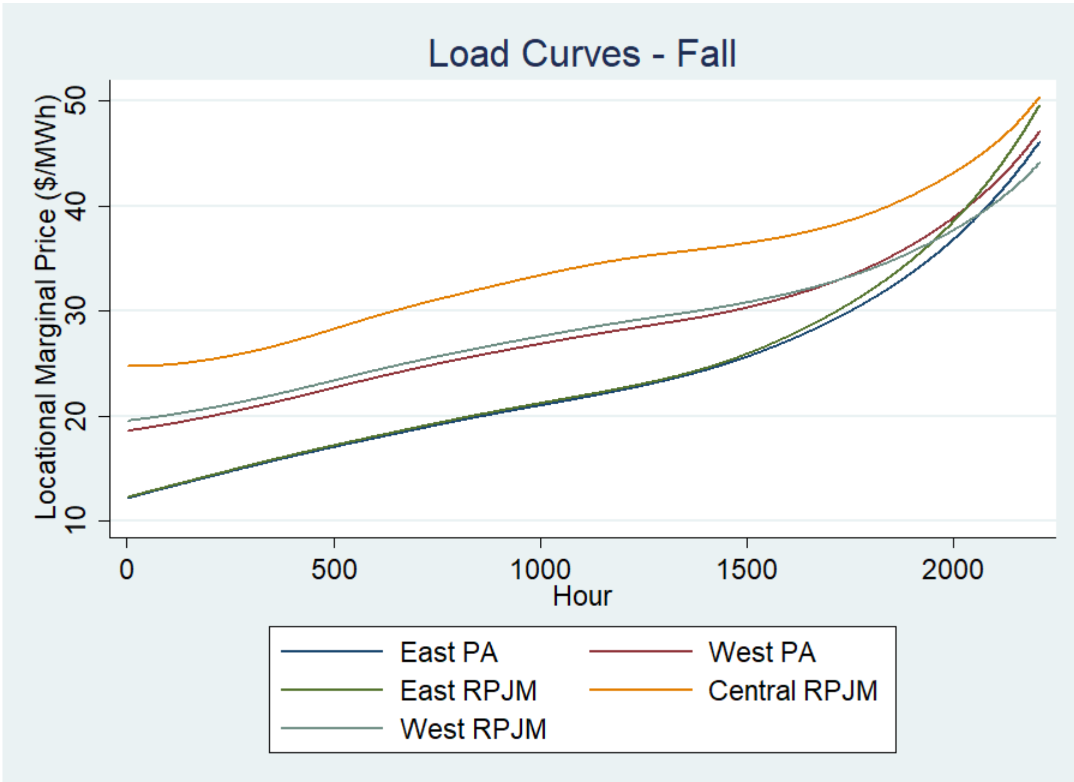


Figure 11: RT LMPs in PJM in Fall 2016



4. Fuel Prices

a. Natural Gas Prices

We get daily gas spot price from Bloomberg for seven gas hubs: Alliance, Dominion North Point, Chicago City Gate, Lebanon OH, TETCO Zone M3, Tennessee Gas Zone 4 - Marcellus and Transco Leidy in 2016, 2017 (for calibration purpose) and 2018 (for validation purpose). Assuming that each power plant buy gas from the hub that is closet to their location in 2016, we map these hubs in GIS and assign each power plant to the gas hub closest to it. We assume power plants buy gas from the same gas hubs in 2017 and 2018.

To calculate gas transportation price, we use natural gas delivered price to the electric power sector from the EIA's Annual Energy Outlook 2017 (AEO 2017) for 2016 prices by census region and aggregate the Bloomberg gas spot prices above also by census region. The gas transportation price for each region is then determined by subtracting the aggregated regional Bloomberg gas spot prices from the EIA's gas delivered price.

The final gas fuel price for each natural gas-fired power plant is determined by the the gas spot price associated with that plant plus the transportation gas price to the census region in which the plant is located.

b. Coal Prices

For coal fuel prices, we use weekly coal spot prices for five main coal basins in 2016 from the EIA: Central Appalachia Basin, Northern Appalachia Basin, Illinois Basin, Powder River Basin and Unita Basin. Coal transportation prices from each coal basin to the states that it historically shipped to are taken from the EIA's Coal transportation rates database, then weighted averaged in each PJM regions (defined in section 2) by modes of transportation (railway, train and truck). We then calculate five weekly total coal price for each plant assuming they could potentially buy coal from the five basins by adding the weekly coal spot prices from the respective basin to the weighted coal transportation price from that basin to the state in which the power plant located. Next, we average these five total coal prices by load segments as defined in section 2 to get the five potential total coal prices for each coal-fired power plant by each segment. The final total coal price for each power plant in each segment is then determined by the minimum total coal prices for that plant in that segment.

c. Oil Prices and Nuclear Prices

Quarterly oil prices for electric power sector by census region are taken from the EIA for actual 2016 data. Annual uranium prices by census region are also taken from the EIA.

e. Other Fuel Prices

Other fuel prices are taken from SNL power plant data, associated with each power plant.

f. Binning Units in Final Dataset

To establish the supply curve, the next step is to group these units in the final dataset into bins of the same or similar attributes. These attributes include total marginal cost (mc), which is the sum of fuel cost, transportation cost and emission cost, fuel type, emission intensity, and location. After the binning process, we reduce 3,095 units in our final dataset to 843 representative units. We then aggregate the capacity of all the units by bin, as well as calculate average heat rate and emission rate by bin and assign them as heat rate and emission for each bin. The transmission unconstrained PJM supply curve is the merit order of these 843 aggregated units.

5. Marginal Cost

a. Emission Cost

Emission cost for each power plant is the sum of SO_2 emission cost and NO_x emission cost. SO_2 emission cost is calculated in $\$/MWh$ as SO_2 current permit (from EIA) $\times$ SO_2 permit rate (in $\$/mmBTu$, from NEEDs data) $\times$ heat rate of the associated power plant $\times \frac{1}{2000,000}$. Similarly, NO_x emission cost is calculated in $\$/MWh$ as NO_x current permit (from EIA) $\times$ NO_x permit rate (in $\$/mmBTu$, from NEEDs data) $\times$ heat rate of the associated power plant $\times \frac{1}{2000,000}$.

b. Marginal Cost

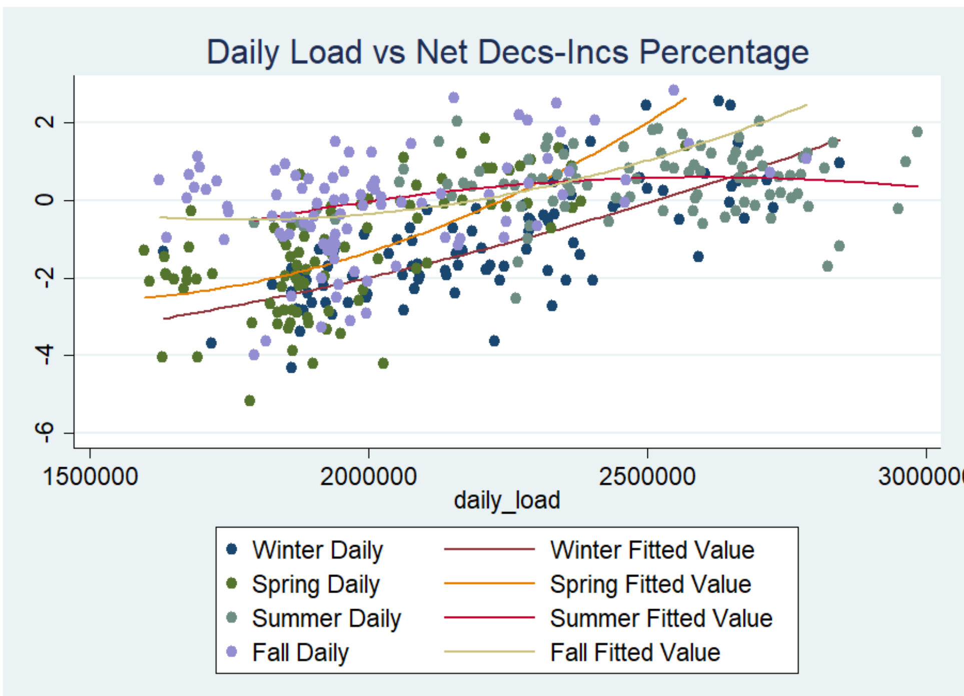
Marginal cost of each power plant is calculated as MC = Fuel Cost + Transportation Cost + Emission Cost + 10% Mark Up, each of these component costs except for the 10% Mark Up is calculated as detailed above. The 10% Mark Up is mentioned in the Monitoring Analytics' 2016 State of the Market as a component of LMP.

6. Virtual Bids

We account for the amount of cleared daily net virtual bid (decs - incs) into our segment loads in our model. We detect a quadratic relationship between daily net virtual bids and daily load in each season. These correlations are shown in the figure below. We use quadratic regression with seasonal fixed effects (W = Winter, S = Spring, Su = Summer, F = Fall) to predict the hourly cleared virtual bid (NVB) and net cleared virtual bid in the load segment level across PJM (L). The daily cleared incs and decs are taken from the dataset “Daily cleared INCs, DECs, and UTCs" from PJM’s data miner 2.

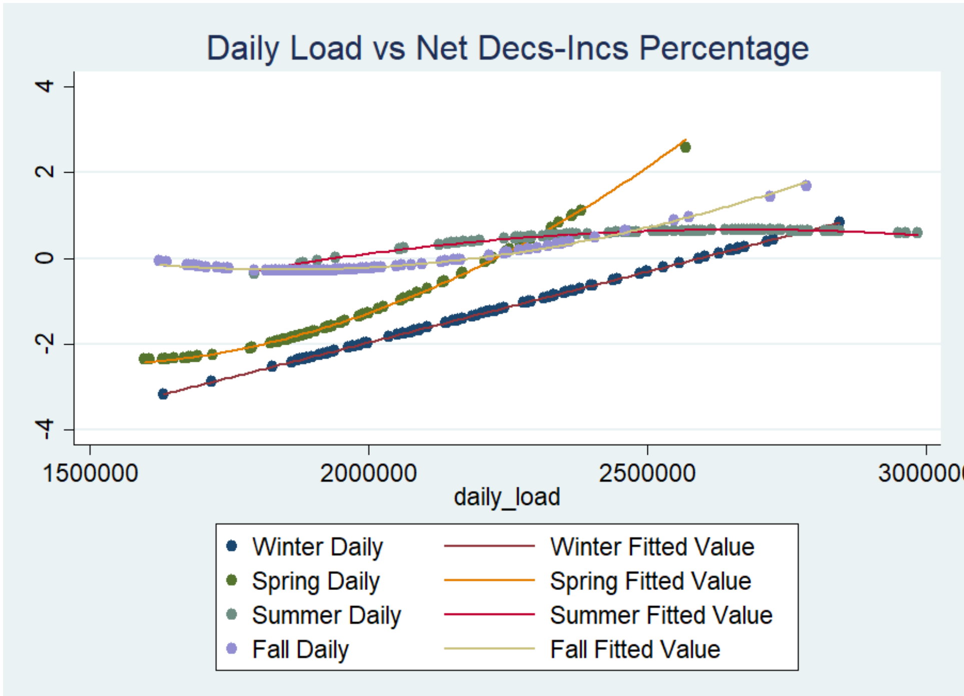
$$\begin{aligned}\mathrm{NVB}_{daily} = {} & \beta_1\left(\mathrm{L}_{daily}\right) + \beta_2\left(\mathrm{L}^2_{daily}\right) + \delta_1(\mathrm{W}) + \delta_2(\mathrm{S}) + \delta_3(\mathrm{Su}) + \delta_4(\mathrm{F}) \\ & + \sigma_1\left(\mathrm{W}\times\mathrm{L}_{daily}\right) + \sigma_2\left(\mathrm{S}\times\mathrm{L}_{daily}\right) + \sigma_3\left(\mathrm{Su}\times\mathrm{L}_{daily}\right) + \sigma_4\left(\mathrm{F}\times\mathrm{L}_{daily}\right) \\ & + \gamma_1\left(\mathrm{W}\times\mathrm{L}^2_{daily}\right) + \gamma_2\left(\mathrm{S}\times\mathrm{L}^2_{daily}\right) + \gamma_3\left(\mathrm{Su}\times\mathrm{L}^2_{daily}\right) + \gamma_4\left(\mathrm{F}\times\mathrm{L}^2_{daily}\right)\end{aligned}$$

Figure 12: Daily Load vs Daily Net Cleared Virtual Bid



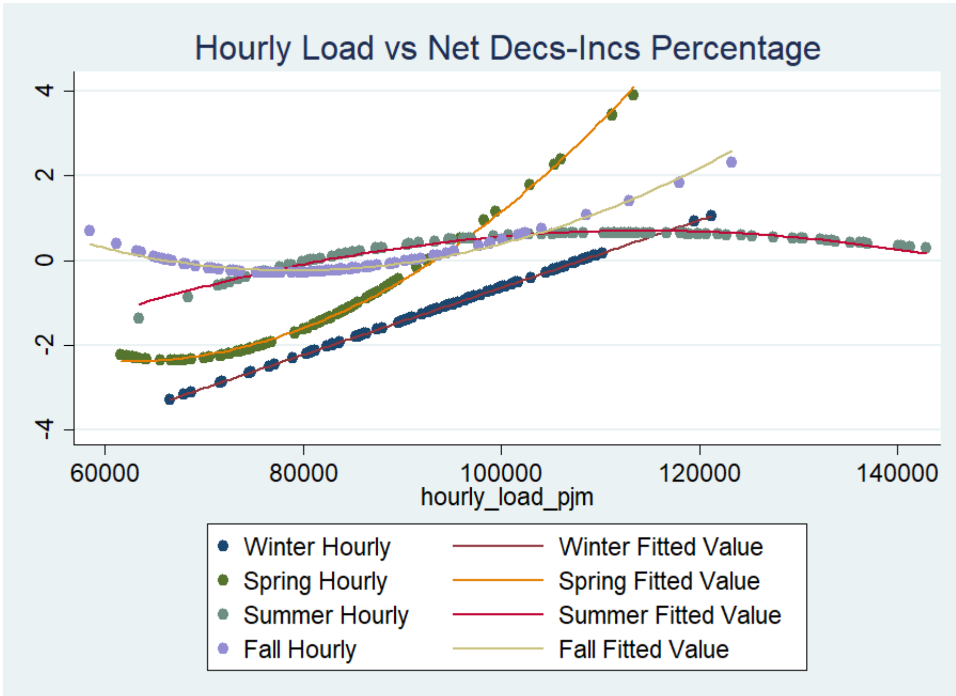
The predicted daily virtual bids from the above regression are shown in the figure below. We can see that the quadratic relationship is a reasonable assumption.

Figure 13: Daily Load vs Predicted Daily Net Cleared Virtual Bid



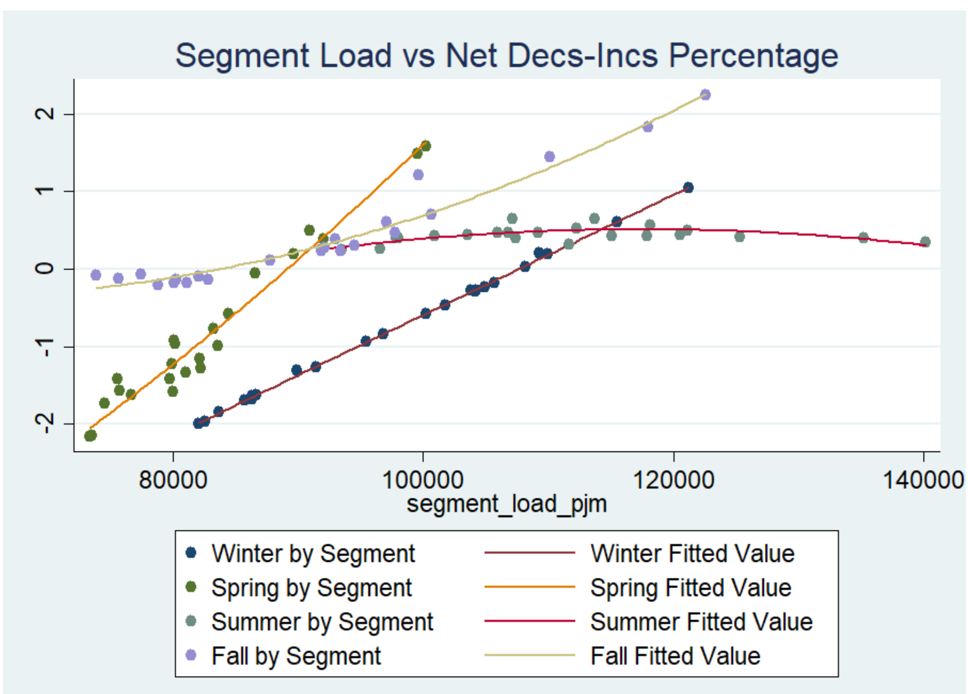
Now, apply the parameters $\beta, \delta, \sigma, \gamma$ found in the regression above (with adjustment to units from daily to hourly) to hourly PJM load, we can predict the net virtual bid cleared every hour across PJM.

Figure 14: Daily Load vs Predicted Hourly Net Cleared Virtual Bid



Summing all the hours in each load segment, we have a predicted cleared net virtual bid in every load segment as a function of segment load:

Figure 15: Daily Load vs Predicted Segment Net Cleared Virtual Bid



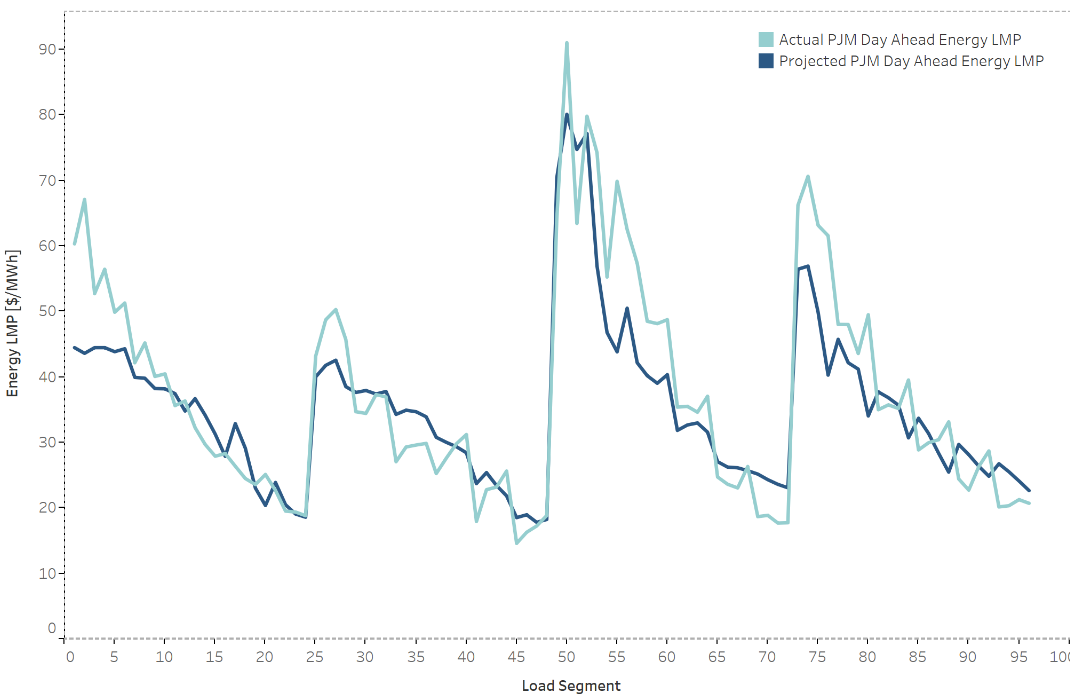
These predicted net cleared virtual bids by segment are divided by the total PJM load in corresponding load segments to find the percentage of net cleared bid in total load in that segment, denoted as z_l, where $l = 1, 2, 3, ..., 96$. The final segment loads used in the model is defined as:

$$L_{il}^* = L_{il}\,(1 + z_l)$$

in which, $i = 1, 2, 3, 4, 5$ are the index for 5 regions in our model and $l = 1, 2, ..., 96$ are the index for 96 load segments in our model. L_{il} is the original load in each load segment in each region and L_{il}^* is the final load in each load segment in each region after accounting for net virtual bid in that segment.

With the addition of virtual bids, the model's prediction of Energy LMP has $R^2 = 0.793$, as shown in figure ??.

Figure 16: Calibration Results for Energy LMP for PJM in 2016.



7. Transmission Network Constraints

Transmission line data are taken from SNL's Operating Transmission Projects Map for 2016. Transmission lines that connect every two zones within two PJM regions are aggregated into single aggregated transmission lines, which reflect the net maximum MWhs that can be transferred in between two PJM regions, as shown in figure **??**. We consider a line to connect between two regions if it connects two ISO market hubs, one in each region. We have in total five aggregated transmission lines among our five PJM regions. The table below shows the five aggregate links among our five LMP regions and their respective aggregate KV.

Table 5: PJM Transmission Networks.

Transmission Line Between	Total KV (kv_i)
PA East and PA West	960
PA East and RPJM East	1,880
PA East and Central RPJM	690
PA East and RPJM West	N/A
PA West and RPJM East	N/A
PA West and Central RPJM	N/A
PA West and RPJM West	5,208
RPJM East and Central RPJM	N/A
RPJM East and RPJM West	N/A
Central RPJM and RPJM West	3,460

To know the actual transmission capacities of these lines, we are still missing the impedance in each line above, which is the aggregation of all individual lines between every two PJM regions. Therefore, there is no one realistic impedance we can assume for each aggregate line. We also do not observe the true transmission capacities which can vary in real time due to many climate factors such as wind speed and direction, solar radiation, temperature, etc... Furthermore, our model is an aggregate model and our objective is to calibrate average congestion LMPs for the five links above, simply adding the transmission capacities between PJM regions does not capture well these aggregate price effects as the true congestion LMPs reflect complicated grid realities such as the complicated and largely unobserved disaggregated transmission system between zones within PJM regions which may vary across seasons and correlate with load. As a result, to calibrate these five aggregate transmission line capacities we search for the optimal values of five scalers in each load segment (sc^*_{il}), with which $sc^*_{il} \times kv_i \times 1,000$ represents the transmission capacities in each load segment that minimizes the LMP congestion loss function across PJM in that load segment, using the method used in Ferreyra (2007).

By performing a grid search of 100,000 iterations of combinations of scalers among the five LMP regions in the range of 0.2 to 2, with increment of 0.2, similar to Ferreyra (2007), in the first stage, we find the optimal model predicted congestion LMPs in 5 PJM regions, $prLMP_{ilc^*}^{cong,stage1}$ where c^* is the index number of the iteration that yields the optimal solution, which is the solution to the the first stage loss minimization:

$$Loss_l^{stage1} = \min_{prLMP_{ilc}^{cong}} \left(\sum_i (daLMP_{il}^{cong} - prLMP_{ilc}^{cong})^2 \right)$$

Next, we can calculate the standard deviations across the five PJM regions of the congestion LMP residuals:

$$std_l^{congLMP} = std \left(\sum_i (daLMP_{il}^{cong} - prLMP_{ilc^*}^{cong,stage1}) \right)$$

In the second stage, we re-perform the grid search that we did in stage 1, only this time, the loss function is weighted by the standard deviations across five PJM regions calculated above. The solution to this grid search is the second stage optimal model predicted LMPs, $prLMP_{ilc^*}^{cong,stage2}$.

$$Loss_l^{stage2} = \min_{prLMP_{ilc}^{cong}} \left(\sum_i \frac{(daLMP_{il}^{cong} - prLMP_{ilc}^{cong})^2}{std_l^{congLMP}} \right)$$

Finally, sc_{ilc^*} are used as initial values for an fmincon search in MATLAB to find the exact scalers (sc_{il}^*) that minimize the aggregate gap between the DA congestion LMPs and the model predicted congestion LMPs across the five PJM regions, using the second stage loss function and limiting the lower and upper bounds of these scalers in between the range of $[0.01, 5]$ for all five transmission links. These optimal scalers give us the final optimal model predicted congestion LMPs, $prLMP_{il}^*$. These optimal results are shown in the figures below.

Figure 17: Calibration Results for Congestion LMP in East PA (Top Row, Left), West PA (Top Row, Right), East RPJM (Second Row, Left), Central RPJM (Second Row, Right) and West RPJM (Bottom Row) in 2016.

Figure 18: Calibration Results for Total LMP in East PA (Top Row, Left), West PA (Top Row, Right), East RPJM (Second Row, Left), Central RPJM (Second Row, Right) and West RPJM (Bottom Row) in 2016. $R^2 = 0.778$.

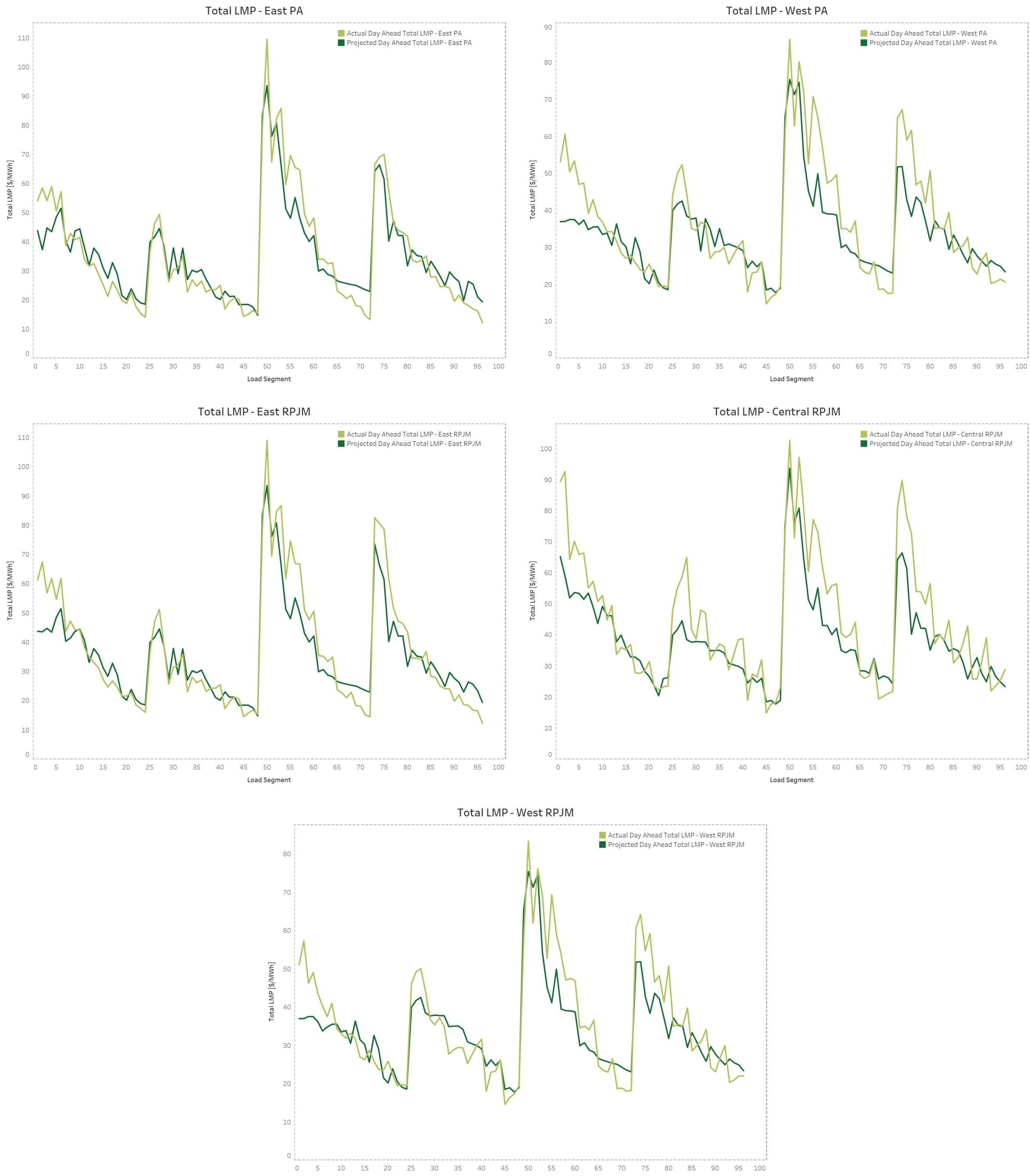


Table 6: Calibration Results for Total Generation in PA and RPJM in 2016 (GWh).

Fuel	Actual - PA	Calibrated Result - PA	Error - PA	Data - RPJM	Calibrated Result - RPJM	Error - RPJM
Coal	54,672	54,838	-0.3%	220,609	220,981	-0.2%
Nuclear	82,924	82,924	0.0%	196,622	196,662	0.0%
Gas	68,048	68,568	-0.8%	146,974	144,557	1.6%
Hydro	2,374	2,375	0.0%	11,312	11,312	0.0%
Wind	3,476	3,476	0.0 %	14,240	14,240	0.0%
Oil	363	353	2.7 %	1,800	1,784	0.9 %
Solar	75	75	0.0%	945	944	0.0%
Biomass	1,883	1,813	3.7%	4,017	3,914	2.5%
Other	1,250	699	44.0%	958	1,311	-36.8%
Total	215,066	215,120	-0.02%	597,478	595,666	0.3%

8. Renewable Portfolio Standards (RPS)

Many states in PJM have legislation on a defined percentage of supplied generation be served by renewable resources, for which definitions vary by state. These are called renewable portfolio standards (RPS). In 2018, there are 9 states that have RPS. They are Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC. There are two states that have voluntary RPS (Virginia and Indiana) and two states that do not have RPS (Kentucky, Tennessee and West Virginia). We only model RPS in the 9 states that have required RPS, of which 4 states (DC, MD, NJ and PA) classify their RPS into tier 1 and tier 2 RPS, under which different eligible renewable energy technologies are clearly defined in each state. The other 5 states (DE, IL, MI, NC and OH) do not classify their RPS into different tiers in 2017 but their eligible technologies are for the most part identical to tier 1 resources and will be modeled as tier 1 resource. By 2030, DC's tier 2 RPS will go down to 0 % and thus in 2030 only tier 1 RPS is modeled for DC. Details on RPS percentages and eligible technologies by tier in each state are shown in table below.

Table 7: List of RPS regulations by State in PJM in 2017.

PJM State	State Number	RPS Tier 1	RPS Tier 2	Solar RPS
DC	1	13%	1.5%	0.98%
DE	2	16%	N/A	1.5%
IL	3	11.5%	N/A	6%
IN	4	N/A	N/A	N/A
KY	5	N/A	N/A	N/A
MD	6	13.1%	2.5%	1.15%
MI	7	10%	N/A	N/A
NC	8	6%	N/A	0.14%
NJ	9	13.5%	2.5%	3%
OH	10	3.5%	N/A	0.22%
PA	11	6%	8.2%	0.2933%
TN	12	N/A	N/A	N/A
VA	13	N/A	N/A	N/A
WV	14	N/A	N/A	N/A

Table 8: List of RPS regulations by State in PJM in 2030.

PJM State	State Number	RPS Tier 1	RPS Tier 2	Solar RPS
DC	1	42%	0%	4.5%
DE	2	25%	N/A	3.5%
IL	3	25%	N/A	6%
IN	4	10%	N/A	N/A
KY	5	N/A	N/A	N/A
MD	6	20%	2.5%	2.5%
MI	7	35%	N/A	N/A
NC	8	12.5%	N/A	0.2%
NJ	9	50%	2.5%	2.21%
OH	10	12.5%	N/A	0.5%
PA	11	8%	10%	0.5%
TN	12	N/A	N/A	N/A
VA	13	N/A	N/A	N/A
WV	14	N/A	N/A	N/A

Table 9: List of state-level RPS eligible technologies by tier

State	No.	Tier 1 RPS	Tier 2 RPS	Eligible Location
DC	1	(1) Solar PV, (2) solar thermal, (3) wind, (4) biomass (>65% efficiency),(5) methane from a landfill or wastewater treatment plant, (6) geothermal, (7) ocean including energy from waves, tides, currents, and thermal differences, (8) fuel cells that produces electricity from a Tier 1 renewable source.	(1) Hydroelectric power other than pump storage generation. The facility must have existed and been operational as of January 1, 2004	Sources must be located (1) within the PJM region or (2) an adjacent state to the PJM region or (3) outside the PJM region or adjacent state but in a control area that is adjacent to the PJM Region, if the electricity is delivered into the PJM Region.
DE	2	(1) Solar, (2) wind, (3) ocean, (4) geothermal, (5) fuel cell powered by renewable fuels, (6) combustion of gas from the anaerobic digestion of organic material, (7) small hydroelectric facility ($\leq$ 30 MW), (8) sustainable biomass excluding waste to energy, (9) landfill methane gas	(1) Units in commercial operation after 12/31/1997. No more than 1 percent of each year's sales may come from resources that are not new	Sources must be located (1) within or (2) imported into the PJM region.
IL	3	(1) Wind, (2) solar thermal energy, (3) PV cells and panels, (4) biodiesel, (5) anaerobic digestion, (6) crops and untreated and unadulterated organic waste biomass, (7) tree waste, in-state landfill gas, (8) hydropower that does not involve new construction or significant expansion of hydropower dams, (9) other alternative sources of environmentally preferable energy.		Sources must be located (1) in IL or (2) from adjoining states if approved by the Illinois Power Agency, or (3) within portions of the PJM and MISO footprint in the US.

Continued on next page

Table 9 – *Continued from previous page*

State	No.	Tier 1 RPS	Tier 2 RPS	Eligible Location
IN* [2]	4	(1) Solar energy, (2) PV cells and panels, (3) dedicated crops grown for energy production, (4) organic waste biomass, (5) hydropower, (6) fuel cells, (7) hydrogen, (8) energy from waste to energy facilities including energy derived from advanced solid waste conversion technologies, (9) energy storage systems or technologies, (10) geothermal energy, (11) coal bed methane, (12) industrial byproduct technologies that use fuel or energy that is a byproduct of an industrial process, (13) waste heat recovery from capturing and reusing the waste heat in industrial processes for heating or for generating mechanical or electrical work, (14) landfill methane recovery, (15) demand side management or energy efficiency initiatives, (16) a clean energy project described in the statute, (17) nuclear energy, (18) distributed generation connected to the grid, (19) combined heat and power, (20) electricity that is generated from natural gas at a facility constructed in Indiana after July 1, 2011 which displaces electrcity generation from an existing coal fired generation facility.		At least 50 percent of RECs must be purchased from resources located within Indiana.
KY	5	No RPS.		

Continued on next page

[2]*: States with voluntary RPS

Table 9 – *Continued from previous page*

State	No.	Tier 1 RPS	Tier 2 RPS	Eligible Location
MD	6	(1) Solar, (2) wind, (3) qualifying biomass, (4) methane from a landfill or wastewater treatment plant, (5) geothermal, (6) ocean, (7) fuel cell powered by methane or biomass, (8) small hydroelectric plant (< 30 MW), (9) poultry litter incineration facilities in Maryland, (10) waste-to-Energy facilities in Maryland, (11) certain geothermal heating and cooling systems and biomass systems that generate thermal energy.	(1) Hydroelectric power other than pumped storage generation	Source must be (1) located in the PJM Region; or (2) outside the area described in item (1) but in a control area that is adjacent to the PJM service territory, if the electricity is delivered into the PJM service territory. Solar resources must be connected to the distribution grid serving Maryland.
MI	7	(1) Biomass, (2) solar PV, (3) solar thermal, (4) wind, (5) geothermal, (6) municipal solid waste (MSW), (7) landfill gas, (8) existing hydroelectric, (9) tidal, wave, and water current (e.g., run of river hydroelectric) resources.		Resources must be located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements.

Continued on next page

Table 9 – *Continued from previous page*

State	No.	Tier 1 RPS	Tier 2 RPS	Eligible Location
NC	8	(1) Solar-electric, (2) solar thermal, (3) wind, (4) hydropower ($\leq$ 10 MW), (5) ocean current or wave energy, (6) biomass that uses Best Available Control Technology (BACT) for air emissions, (7) landfill gas, (8) combined heat and power (CHP) using waste heat from renewables, (9) hydrogen derived from renewables, (10) and electricity demand reduction. Up to 25% of the requirement may be met through energy efficiency technologies, including CHP systems powered by non-renewable fuels. After 2021, up to 40% of the standard may be met through energy efficiency.		Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere.
NJ	9	(1) Solar technologies, (2) PV technologies, (3) wind energy, (4) fuel cells powered by renewable fuels, (4) geothermal technologies, (5) wave or tidal action, (6) methane gas from landfills or a biomass facility provided that the biomass is cultivated and harvested in a sustainable manner, (7) hydroelectric facilities ($\leq$ 3 MW) that are located in NJ and placed in service after July 23, 2012.	(1) Resource recovery facility (subject to qualifications), (2) small hydroelectric power facility (< 30 MW)	Source must be (1) within or (2) delivered into the PJM region. If the latter, the energy must have been generated at a facility that commenced construction on or after January 1, 2003

Continued on next page

Table 9 – *Continued from previous page*

State	No.	Tier 1 RPS	Tier 2 RPS	Eligible Location
OH	10	(1) Solar photovoltaics (PV), (2) solar thermal technologies used to produce electricity, (3) wind, (4) geothermal, (5) biomass, (6) biologically derived methane gas, landfill gas, certain non-treated waste biomass products, (7) solid waste (as long as the process to convert it to electricity does not include combustion), (8) fuel cells that generate electricity, certain storage facilities, and qualified hydroelectric facilities, (9) certain cogeneration and waste heat recovery system technologies that meet specific requirements, (10) distributed generation systems used by customers to generate electricity using the aforementioned eligible renewable resources, (11) run-of-the-river hydroelectric systems on the Ohio River (>40 MW).		Source must be (1) in-state facilities or (2) can be shown to be deliverable into the state.
PA	11	(1) Solar PV and solar thermal energy, (2) wind power, (3) Low-impact hydropower, (4) geothermal energy, (5) biologically derived methane gas, (6) generation of electricity utilizing by-products of the pulping process and wood manufacturing process including bark, wood chips, sawdust and lignin in spent pulping liquors (in-state resources only), (7) biomass energy, (8) coal mine methane.	(1) Waste coal, (2) distributed generation systems, (3) demand-side management, (4) large-scale hydropower (including pumped storage), (5) municipal solid waste, (6) generation of electricity utilizing by-products of the pulping process and wood manufacturing process including bark, wood chips, sawdust and lignin in spent pulping liquors, (7) integrated combined coal gasification technology.	Source must be (1) located inside the geographical boundaries of this Commonwealth or (2) within the service territory of any regional transmission organization that manages the transmission system in any part of this Commonwealth.

Continued on next page

Table 9 – *Continued from previous page*

State	No.	Tier 1 RPS	Tier 2 RPS	Eligible Location
TN	12	No RPS		
VA*	13	(1) Solar, (2) wind power, (3) geothermal energy, (4) hydropower, (5) wave, (6) tidal, (7) biomass energy.		Electricity must be generated or purchased in (1) Virginia or (2) in the PJM service territory.
WV	14	No RPS		

End of long table.

9. Capacity Expansion

There are three technologies being expanded each year in each state in our model: Natural Gas, Wind and Solar. These are the technologies that are most likely to be developed due to low gas prices and increase in demand for clean energy. We assume the average capacity factors across all gas, wind and solar units in our model in 2016 for these technologies. Specifically, the assumed capacity factor for a new natural gas unit is 0.961, for a new wind unit is 0.295, and for a new solar unit is 0.17. We also assume the new wind and solar capacities within each state are available to be used to satisfy the RPS requirement for that state for that year.

Marginal cost for the new natural gas unit in a state is based on the gas price in that state. Marginal costs for all new wind and solar units are zeros.

Capital costs for the three technologies for the basecase (2017 no policy with capacity expansion) are determined by solving the error minimization problem in which the error is the difference between the actual capacities expanded by technology for PA and RPJM in 2017 and the predicted capacities expanded by technology from our model. Data from new capacities in PJM are taken from PJM's New Service Queue database (https://www.pjm.com/planning/services-requests/interconnection-queues.aspx). In 2017, there are 1,340 MW of new natural gas capacity, 0 MW of new wind capacity and 0 MW of new solar capacity in PA. In the same year, RPJM observed 1,626 MW of new natural gas capacity, 126 MW of new wind capacity and 204 MW of new solar capacity. Our model's calibration results for new capacity by technology in 2017 are as follows.

Table 10: Capacity Expansion Calibration Results in PJM in 2017.

Technology	PA-Model	PA-Actual	PRJM-Model	RPJM-Actual
Natural Gas	1,270	1,340	1,626	1,766
Wind	0	0	156	126
Solar	0	0	194	204

10. List of Calibrated Parameters

Table 11: List of Calibrated Parameters.

Parameters	
Supply Side	**Explanation**
$B = 843$	Number of Aggregated Units (Bins)
$I = 5$	Number of Nodes (index i)
J_i	Number of Units in each Node (index j)
c_{ij}^{vom}	Variable O & M Cost of Unit j in Node i
c_{ij}^{f}	Variable Fuel Cost of Unit j in Node i
mc_{ij}	Total Marginal Cost of Unit j in Node i
γ_{ij}	Capacity of Unit j in Node i
ϕ_{ij}	Emission Intensity of Unit j in Node i
h_{ij}	Heat Rate of Unit j in Node i
η^S	Supply Elasticity
f_{ij}	Fuel Type of Unit j in Node i
pt_{ij}	Plant Type of Unit j in Node i
l_{ij}^c	Census Region of Unit j in Node i
l_{ij}^z	PJM Load Zone of Unit j in Node i
m_{il}	Supply Demand Function Slope In Region i and Load Segment l.
b_{il}	Supply Function Intercept In Region i and Load Segment l
K_s^{nf}	Capital Costs for New Capacity in State s and by Technology nf
REC_{PA}^{ext}	The Amount of External RECs Available to Satisfy RPS in PA
REC_{RPJM}^{ext}	The Amount of External RECs Available to Satisfy RPS in RPJM
Demand Side	
$L = 96$	Number of Load Segments
$\eta^D = 0.05$ [3]	Demand Elasticity
n_{il}	Demand Function Slope In Region i and Load Segment l.
c_{il}	Demand Function Intercept In Region i and Load Segment l.
z_l	Percentage of net cleared virtual bid in total load for load segment l.
Transmission & Market	
$\bar{f}_{il}$	Transmission Constraint in Region i and Load Segment l
$\bar{e}_{PA}, \bar{e}_{RPJM}$	Emission Caps in Pennsylvania and in the rest of PRJM

11. Growth Rate

a. Load Growth Rates

Annual load growth rate for future load projection in the model is 0.42% increase from the previous year, which is the result of a linear forecast based on the actual loads of the past five years in PJM as reported by the Market Monitoring Analytics in their State of the Market Reports 2013-2018.

b. Fuel Price Growth Rates

Fuel prices are grown from the 2018 fuel price baseline. We use data for fuel price growth rates from the 2018 Annual Energy Outlook (AEO 2018) for the Mid-Atlantic region published by the U.S. Energy Information Administration (EIA). We apply price growth rates for natural gas, coal, oil and uranium and assume that prices for other fuel types stay the same as in 2018. Compared to the 2018 baseline, the fuel price growth rates from 2019-2030 used in our model are as follows:

Table 12: Fuel Price Growth Rates 2019 - 2030 (in %).

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas	9.03	14.71	11.94	12.18	14.69	16.38	18.89	18.98	19.77	19.36	21.82	21.63
Coal	0.84	1.92	2.07	2.02	2.00	2.42	2.82	2.86	2.63	2.66	3.18	3.40
Distillate Oil	8.98	33.91	46.75	53.93	59.90	61.07	61.73	61.88	63.76	65.23	67.84	69.27
Uranium	0.15	0.46	0.62	0.77	1.08	1.23	1.54	1.69	2.00	2.16	2.31	2.62

c. Capital Cost Growth Rates

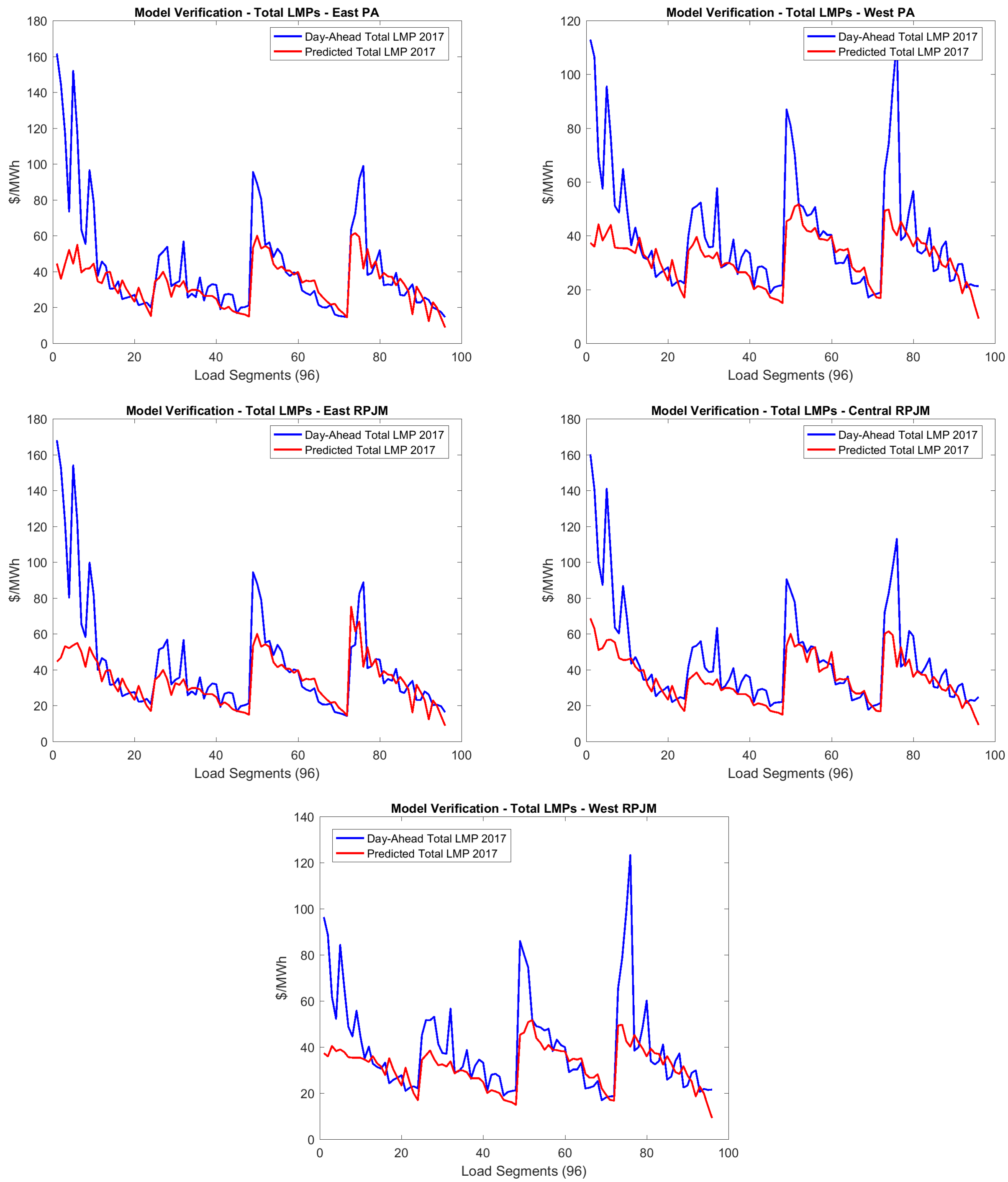
For new natural gas unit's capital cost, we assume no growth rate, which means capital cost for new natural gas unit is still kept at $\$73,000$ MW-year. For new wind unit's capital cost, Wiser et al (2016) surveys different wind technology experts and finds that onshore wind costs would decline by 24% by 2030 relative to 2014, which is translated to an annual average reduction rate of 1.7%. For new solar PV system's capital cost, we look at the EIA Sunshot Initiative which has targeted a 50%reduction in utility scale solar PV costs from their 2020 target, which was achieved in 2017, to their 2030 target. We think this may be too ambitious so we cut it in half and assume a 25%

reduction in PV costs by 2030 relative to 2017. This implies an annual average PV reduction rate in PV costs of 2.19%.

12. Model Validation

We validate our model against 2018 data. We use PJM's load growth of -2.372% since actual total hourly load in 2017 is 2.372% lower than total hourly load in 2016. We use data for fuel price growth rates from the 2017 Annual Energy Outlook (AEO 2017) published by the U.S. Energy Information Administration (EIA), in which gas price growth rate is 18.16%, oil price growth rate is = 16.17%, coal price growth rate is -2.397%, and nuclear price growth rate is 0.1548%. Model predicted load matches actual 2017 load with an $R^2 = 0.8701$. The verification results for total LMPs in 2017 are shown below.

Figure 19: Verification Results for Total LMP in East PA (Top Row, Left), West PA (Top Row, Right), East RPJM (Second Row, Left), Central RPJM (Second Row, Right) and West RPJM (Bottom Row) in 2017. $R^2 = 0.36$.



Numerical Model Formulation

Parameters

a. Model Scope:

I : Number of PJM regions $(= 5)$. Index for PJM regions is i.

R : Number of PJM regions for energy policy imposition $(= 2)$.

Index is r, $r = 1$ if region is PA and $r = 2$ if PJM is RPJM.

S : Number of PJM states for RPS $(= 14)$.

Index is s, see Table 7 for details on these states.

L : Index for time periods (or load segments). Index for load segment is l.

δ_l : Number of hours in load segment l (Varying each load segment).

b. Supply Side:

J : Number of generators in each region. Index for generators is j.

g_{ilj} : Generation in region i, load segment l and by generator j.

$\bar{g}_{ilj}$: Generation capacity for generator j in region i and load segment l.

d_{il} : Demand for power in region i and load segment l.

ϕ_{ij} : Emission intensity of generator j in region i

$\bar{f}_{ihl}$: Transmission constraint between region s and region h in load segment l.

f_{il} : Net flow into region i in load segment h.

b_{ilj} : Supply curve intercept (marginal cost of producing 1 MWh in region i, load segment l, by generator j.)

$= mc_{ilj}$, in which mc_{ilj} is marginal cost of unit j in region i in load segment l.

m_{ilj} : Supply curve slope in region i, load segment l, for generator j.

c. Demand Side:

n_{il} : Demand curve slope in region i, load segment l

$$= \left(1 + \frac{1}{\eta^D}\right) \cdot LMP_{i,l}, \quad \text{where: } \eta^D = 0.05 \text{ is demand elasticity and } LMP_{il} \text{ is actual LMP}$$

c_{il} : Demand curve intercept in region i and load segment l

$$= \left(\frac{1}{\eta_D}\right) \cdot \left(\frac{LMP_{i,l}}{L_{il}}\right), \quad \text{where: } L_{il} \text{ is actual load in region } i \text{ and load segment } l.$$

z_l : Percentage of net cleared virtual bid in total load for load segment l.

b. Emission and RPS Policies:

$\bar{e}_r$: Annual emission cap imposed on region r. In this model, there are two emission caps, $\bar{e}_{PA}$ and $\bar{e}_{RPJM}$.

$\bar{e}$: Total annual emission cap accross all PJM.

$\bar{ra}_r$:Annual emission rate cap imposed on region r.

In this model, there are two emission rate caps, $\bar{ra}_{PA}$ and $\bar{ra}_{RPJM}$.$\bar{r}$: Tot

$$= \sum_r \bar{ra}_r = \bar{ra}_{PA} + \bar{ra}_{RPJM}.$$

$\bar{re}_s$: Annual MWh percentage of generation from renewable energy imposed on state s.

$\bar{se}_s$: Annual MWh percentage of generation from solar energy imposed on state s.

Functional Forms

$$\text{Total cost for generator } j \text{ in region } i\text{, load segment } l\text{: } TC_{ilj} = \left(\frac{m_{ilj}}{2} g_{ilj}^2 + b_{ilj} g_{ilj}\right)$$

$$\text{Total benefit in region } i\text{, load segment } l\text{: } TB_{ilj} = \left(-\frac{n_{il}}{2} d_{il}^2 + c_{il} d_{il}\right)$$

$$\text{Marginal Cost: } MC_l = m_{ilj} g_{ilj} + b_{ilj}$$

$$\text{Marginal Benefit: } MB_l = -n_{il} d_{il} + c_{il}$$

1. The No Policy Case (Base Case)

The social planner maximizes total social welfare (TB - TC) subject to system and existing policies (RPS) constraints.

$$\max_{g_{ilj}, d_{il}, f_{ihl}} \left\{ \sum_i \sum_l \left[\delta_l \left(-\frac{n_{il}}{2} d_{il}^2 + c_{il} d_{il} \right) - \sum_j \delta_l \left(\frac{m_{ilj}}{2} g_{ilj}^2 + b_{ilj} g_{ilj} \right) \right] \right\}$$

$$\begin{aligned}
\text{s.t:} \quad & d_{il} \geq 0 \quad \forall i, l \\
& 0 \leq g_{ilj} \leq \bar{g}_{ilj} \quad \forall i, l, j \\
& -\bar{f}_{ih} \leq f_{ih} \leq \bar{f}_{ih} \quad \forall i, h \\
& \sum_j g_{ilj} + f_{il} \geq d_{il}(1 + z_l + loss_l) \quad \forall i, l \\
& \frac{\sum_l \left(\sum_{j=\text{tier 1 or 2 RPS eligible units}} g_{slj} \right) + \sum_{jr} REC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{re}_{sa}, \\
& \qquad \text{where: a = tier 1,2 RPS.} \\
& \frac{\sum_l \left(\sum_{j=\text{S}} g_{slj} \right) + \sum_{jr} SREC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{se}_s
\end{aligned}$$

2. No Policy with Addition of Capacity Expansion

In this case, the social planner maximizes total social welfare (TB - TC) (just like the no-policy case above) with the addition of capacity expansion in natural gas, solar and wind capacities in the 14 state network, subject to the same system and RPS constraints and new capacity constraints.

$$\max_{g_{ilj}, d_{il}, f_{ihl}, K_s^{nf}, g_{sl}^{nf}} \left\{ \sum_i \sum_l \left[\delta_l \left(-\frac{n_{il}}{2} d_{il}^2 + c_{il} d_{il} \right) - \sum_j \delta_l \left(\frac{m_{ilj}}{2} g_{ilj}^2 + b_{ilj} g_{ilj} \right) \right] \right.$$
$$\left. - \sum_{s \in i} \sum_{nf} C_s^{nf} K_s^{nf} - \sum_{s \in i} \sum_l \delta_l \sum_{nf} mc_{sl}^{nf} g_{sl}^{nf} \right\}$$

$$\text{s.t:} \quad d_{il} \geq 0 \quad \forall i, l$$

$$0 \leq g_{ilj} \leq \bar{g}_{ilj} \quad \forall i, l, j$$

$$-\bar{f}_{ih} \leq f_{ih} \leq \bar{f}_{ih} \quad \forall i, h$$

$$K_s^{nf} \geq 0$$

$$0 \leq g_{il}^{nf} \leq K_s^{nf} \times avail_s^{nf}$$

$$\sum_j g_{ilj} + \sum_{s \in i} \sum_{nf} g_{sl}^{nf} + f_{il} \geq d_{il}(1 + z_l + loss_l) \quad \forall i, l$$

$$\frac{\sum_l \left(\sum_{j=\text{tier 1 or 2 RPS eligible units}} g_{slj} + \sum_{nf=\text{W,S}} g_{sl}^{nf} \right) + \sum_{jr} REC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{re}_{sa},$$

where: a = tier 1,2 RPS.

$$\frac{\sum_l \left(\sum_{j=\text{S}} g_{slj} + \sum_{nf=\text{S}} g_{sl}^{nf} \right) + \sum_{jr} SREC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{se}_s$$

3. Intrastate Permit Trading

a. Mass-Based

The social planner maximizes total social welfare (TB - TC) subject to system constraints, RPS and new capacity constraints and mass-based intrastate permit trading regime constraint.

$$\max_{g_{ilj},d_{il},f_{ihl},K_s^{nf},g_{sl}^{nf}} \left\{ \sum_i \sum_l \left[\delta_l \left(-\frac{n_{il}}{2} d_{il}^2 + c_{il} d_{il} \right) - \sum_j \delta_l \left(\frac{m_{ilj}}{2} g_{ilj}^2 + b_{ilj} g_{ilj} \right) \right] \right.$$
$$\left. - \sum_{s \in i} \sum_{nf} C_s^{nf} K_s^{nf} - \sum_{s \in i} \sum_l \delta_l \sum_{nf} mc_{sl}^{nf} g_{il}^{nf} \right\}$$

s.t: $d_{il} \geq 0 \quad \forall i, l$

$$0 \leq g_{ilj} \leq \bar{g}_{ilj} \quad \forall i, l, j$$

$$-\bar{f}_{ih} \leq f_{ih} \leq \bar{f}_{ih} \quad \forall i, h$$

$$K_s^{nf} \geq 0$$

$$0 \leq g_{sl}^{nf} \leq K_s^{nf} \times avail_s^{nf}$$

$$\sum_j g_{ilj} + \sum_{s \in i} \sum_{nf} g_{sl}^{nf} + f_{il} \geq d_{il}(1 + z_l + loss_l) \quad \forall i, l$$

$$\frac{\sum_l \left(\sum_{j=\text{tier 1 or 2 RPS eligible units}} g_{slj} + \sum_{nf=\text{W,S}} g_{sl}^{nf} \right) + \sum_{jr} REC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{re}_{sa},$$

where: a = tier 1,2 RPS.

$$\frac{\sum_l \left(\sum_{j=\text{S}} g_{slj} + \sum_{nf=\text{S}} g_{sl}^{nf} \right) + \sum_{jr} SREC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{se}_s$$

$$\sum_{i \in r} \sum_l \sum_j \phi_{i,j} g_{il,j} \leq \bar{e}_r$$

b. Rate-Based

The social planner maximizes total social welfare (TB - TC) subject to system constraints, RPS and new capacity constraints and rate-based intrastate permit trading regime constraint:

$$\max_{g_{ilj}, d_{il}, f_{ihl}, K_s^{nf}, g_{sl}^{nf}} \left\{ \sum_i \sum_l \left[\delta_l \left(-\frac{n_{il}}{2} d_{il}^2 + c_{il} d_{il} \right) - \sum_j \delta_l \left(\frac{m_{ilj}}{2} g_{ilj}^2 + b_{ilj} g_{ilj} \right) \right] \right.$$
$$\left. - \sum_{s \in i} \sum_{nf} C_s^{nf} K_s^{nf} - \sum_{s \in i} \sum_l \delta_l \sum_{nf} mc_{sl}^{nf} g_{sl}^{nf} \right\}$$

$$\begin{aligned}
\text{s.t:} \quad & d_{il} \geq 0 \quad \forall i, l \\
& 0 \leq g_{ilj} \leq \bar{g}_{ilj} \quad \forall i, l, j \\
& -\bar{f}_{ih} \leq f_{ih} \leq \bar{f}_{ih} \quad \forall i, h \\
& K_s^{nf} \geq 0 \\
& 0 \leq g_{sl}^{nf} \leq K_s^{nf} \times avail_s^{nf} \\
& \sum_j g_{ilj} + \sum_{s \in i} \sum_{nf} g_{sl}^{nf} + f_{il} \geq d_{il}(1 + z_l + loss_l) \quad \forall i, l \\
& \frac{\sum_l \left(\sum_{j = \text{tier 1 or 2 RPS eligible units}} g_{slj} + \sum_{nf = \text{W,S}} g_{sl}^{nf} \right) + \sum_{jr} REC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{re}_{sa},
\end{aligned}$$

where: a = tier 1,2 RPS.

$$\frac{\sum_l \left(\sum_{j = \text{S}} g_{slj} + \sum_{nf = \text{S}} g_{sl}^{nf} \right) + \sum_{jr} SREC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{se}_s$$

4. Interstate Permit Trading

a. Mass-Based

The social planner maximizes total social welfare (TB - TC) subject to system constraints, RPS and new capacity constraints and mass-based interstate permit trading regime constraint.

$$\max_{g_{ilj}, d_{il}, f_{ihl}, K_s^{nf}, g_{sl}^{nf}} \left\{ \sum_i \sum_l \left[\delta_l \left(-\frac{n_{il}}{2} d_{il}^2 + c_{il} d_{il} \right) - \sum_j \delta_l \left(\frac{m_{ilj}}{2} g_{ilj}^2 + b_{ilj} g_{ilj} \right) \right] \right.$$
$$\left. - \sum_{s \in i} \sum_{nf} C_s^{nf} K_s^{nf} - \sum_{s \in i} \sum_l \delta_l \sum_{nf} mc_{il}^{nf} g_{il}^{nf} \right\}$$

s.t: $d_{il} \geq 0 \quad \forall i, l$

$$0 \leq g_{ilj} \leq \bar{g}_{ilj} \quad \forall i, l, j$$

$$-\bar{f}_{ih} \leq f_{ih} \leq \bar{f}_{ih} \quad \forall i, h$$

$$K_s^{nf} \geq 0$$

$$0 \leq g_{sl}^{nf} \leq K_s^{nf} \times avail_s^{nf}$$

$$\sum_j g_{ilj} + \sum_{s \in i} \sum_{nf} g_{sl}^{nf} + f_{il} \geq d_{il}(1 + z_l + loss_l) \quad \forall i, l$$

$$\frac{\sum_l \left(\sum_{j=\text{tier 1 or 2 RPS eligible units}} g_{slj} + \sum_{nf=\text{W,S}} g_{sl}^{nf} \right) + \sum_{jr} REC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{re}_{sa},$$

where: a = tier 1,2 RPS.

$$\frac{\sum_l \left(\sum_{j=\text{S}} g_{slj} + \sum_{nf=\text{S}} g_{sl}^{nf} \right) + \sum_{jr} SREC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{se}_s$$

$$\sum_i \sum_l \sum_j \phi_{i,j} g_{il,j} \leq \sum_r \bar{e}_r = \bar{e}$$

b. Rate-Based

The social planner maximizes total social welfare (TB - TC) subject to system constraints, RPS and new capacity constraints and rate-based interstate permit trading regime constraint:

$$\max_{g_{ilj}, d_{il}, f_{ihl}, K_s^{nf}, g_{sl}^{nf}} \Bigg\{ \sum_i \sum_l \left[\delta_l \left(-\frac{n_{il}}{2} d_{il}^2 + c_{il} d_{il} \right) - \sum_j \delta_l \left(\frac{m_{ilj}}{2} g_{ilj}^2 + b_{ilj} g_{ilj} \right) \right]$$
$$- \sum_{s \in i} \sum_{nf} C_s^{nf} K_s^{nf} - \sum_{s \in i} \sum_l \delta_l \sum_{nf} mc_{il}^{nf} g_{il}^{nf} \Bigg\}$$

$$\begin{aligned}
\text{s.t:} \quad & d_{il} \geq 0 \quad \forall i, l \\
& 0 \leq g_{ilj} \leq \bar{g}_{ilj} \quad \forall i, l, j \\
& -\bar{f}_{ih} \leq f_{ih} \leq \bar{f}_{ih} \quad \forall i, h \\
& K_s^{nf} \geq 0 \\
& 0 \leq g_{sl}^{nf} \leq K_s^{nf} \times avail_s^{nf} \\
& \sum_j g_{ilj} + \sum_{s \in i} \sum_{nf} g_{sl}^{nf} + f_{il} \geq d_{il}(1 + z_l + loss_l) \quad \forall i, l \\
& \frac{\sum_l \left(\sum_{j = \text{tier 1 or 2 RPS eligible units}} g_{slj} + \sum_{nf = \text{W,S}} g_{sl}^{nf} \right) + \sum_{jr} REC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{re}_{sa},
\end{aligned}$$

where: a = tier 1,2 RPS.

$$\frac{\sum_l \left(\sum_{j = \text{S}} g_{slj} + \sum_{nf = \text{S}} g_{sl}^{nf} \right) + \sum_{jr} SREC_{jr,s}^{ext}}{\sum_l \left(\sum_j g_{slj} + \sum_{nf} g_{sl}^{nf} \right)} \geq \bar{se}_s$$

$$\frac{\sum_i \sum_l \sum_j \phi_{ij} g_{ilj}}{\sum_i \sum_l \sum_j g_{ilj}} \leq \sum_r \bar{ra}_r \quad \forall r$$

5. Welfare Calculation

i. General:

$$CS = \sum_i \sum_l \left[\underbrace{\delta_l \left(-\frac{n_{il}}{2} d_{il}^2 + c_{il} d_{il} \right)}_{\text{Consumer's Benefit}} - \underbrace{\delta_l p_{il} \left(\sum_j g_{ilj} + \sum_{nf} g_{il}^{nf} + \sum_h f_{ihl} \right)}_{\text{Consumer's Cost}} \right]$$

$$PS = \sum_i \sum_l \left[\underbrace{\delta_l p_{il} \left(\sum_j g_{ilj} + \sum_{nf} g_{il}^{nf} \right)}_{\text{Producer's Revenue}} - \underbrace{\sum_j \delta_l \left(\frac{m_{ilj}}{2} g_{ilj}^2 + b_{ilj} g_{ilj} \right)}_{\text{Producer's Generation Cost}} - \underbrace{\sum_j \delta_l \lambda_{i \in s} e_{ilj} g_{ilj}}_{\text{Producer's Emission Cost}} \right]$$
$$- \underbrace{\sum_i \sum_{nf} C_i^{nf} K_i^{nf}}_{\text{Producer's New Generation Capital Cost}} - \underbrace{\sum_i \sum_l \delta_l \sum_{nf} mc_{il}^{nf} g_{il}^{nf}}_{\text{Producer's New Generation Cost}}$$

$$\begin{aligned} CR &= \sum_i \sum_l \delta_l p_{il} \sum_h f_{ihl} \\ &= \sum_l \left[f_{12l} \left(p_{1l} - p_{2l} \right) + f_{13l} \left(p_{1l} - p_{3l} \right) + f_{14l} \left(p_{1l} - p_{4l} \right) + f_{25l} \left(p_{2l} - p_{5l} \right) + f_{45l} \left(p_{4l} - p_{5l} \right) \right] \end{aligned}$$

$$PV = \sum_r \lambda_r \bar{e}_s$$

ii. Specifically:

$$CS = \sum_i \sum_l \left[\underbrace{\delta_l \left(-\frac{n_{il}}{2} d_{il}^2 + c_{il} d_{il} \right) - \delta_l p_{il} d_{il}}_{CS^{no-loss}} - \underbrace{\delta_l p_{il} d_{il} \hat{z}}_{CS^{loss}} \right]$$

$$\begin{aligned} PS = & \underbrace{\sum_i \sum_l \left[\delta_l p_{il} \sum_j g_{ilj} - \sum_j \delta_l \left(\frac{m_{ilj}}{2} g_{ilj}^2 + b_{ilj} g_{ilj} \right) - \sum_j \delta_l \lambda_{i \in s} e_{ilj} g_{ilj} \right]}_{PS^{old}} \\ & + \underbrace{\delta_l p_{il} \sum_{nf} g_{il}^{nf} - \sum_i \sum_l \delta_l \sum_{nf} mc_{il}^{nf} g_{il}^{nf} - \sum_i \sum_{nf} C_i^{nf} K_i^{nf}}_{PS^{new}} \end{aligned}$$

$$\begin{aligned} CR &= \sum_i \sum_l \delta_l p_{il} \sum_h f_{ihl} \\ &= \sum_l \left[f_{12l} \left(p_{1l} - p_{2l} \right) + f_{13l} \left(p_{1l} - p_{3l} \right) + f_{14l} \left(p_{1l} - p_{4l} \right) + f_{25l} \left(p_{2l} - p_{5l} \right) + f_{45l} \left(p_{4l} - p_{5l} \right) \right] \end{aligned}$$

$$PV = \sum_r \lambda_r \bar{e}_s$$