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Estimating zonal electricity supply curves in transmission-constrained electricity markets

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ABSTRACT

Many important electricity policy initiatives would directly affect the operation of electric power networks. This paper develops a method for estimating short-run zonal supply curves in transmission-constrained electricity markets that can be implemented quickly by policy analysts with training in statistical methods and with publicly available data. Our model enables analysis of distributional impacts of policies affecting operation of electric power grid. The method uses fuel prices and zonal electric loads to determine piecewise supply curves, identifying zonal electricity price and marginal fuel. We illustrate our methodology by estimating zonal impacts of Pennsylvania's Act 129, an energy efficiency and conservation policy. For most utilities in Pennsylvania, Act 129 would reduce the influence of natural gas on electricity price formation and increase the influence of coal. The total resulted savings would be around 267 million dollars, 82 percent of which would be enjoyed by the customers in Pennsylvania. We also analyze the impacts of imposing a $35/ton tax on carbon dioxide emissions. Our results show that the policy would increase the average prices in PJM by 47–89 percent under different fuel price scenarios in the short run, and would lead to short-run interfuel substitution between natural gas and coal.

1. Introduction

Many energy and environmental policy initiatives (including emissions regulations; renewable portfolio standards; and efficiency policies) would affect the operation of electric power grid. Analysis of such policies is however difficult in the absence of reliable models of the electric power system. The North American power transmission grid has been called "the largest and most complex machine in the world" [1]. Detailed modeling of the system requires complete engineering data on every element of the system such as transmission lines, transformers and generators. This engineering approach is often not feasible in the context of policy analysis due to the proprietary nature of the data and engineering model complexity. Moreover, policy analysis involves the study of future scenarios. Thus, the inputs to the model should be estimated for the future, which always involves some degree of uncertainty. Since the engineering models need detailed data, the set of input uncertainties becomes extremely large. There exist, many other methods in the literature for forecasting short term electricity prices, including probabilistic estimation of price duration curves [2], short term forecast with fuzzy neural networks [3,4], transfer functions [5], and linear and nonlinear time series [6–9]. These methods are designed to forecast short term prices from hours to a week ahead. They estimate short-term prices well but cannot be used in policy analysis, where acceptable performance over longer periods of time is needed. Abstract equilibrium models such as [10] can provide insights into strategic gaming and market design efficiency, but cannot be directly applied to real markets.

As a result, many policy models in the existing literature neglect the effects of the transmission system and use the relatively simple dispatch curve models [11–19]. In order to construct a dispatch curve, power plants in a system are sorted according to their marginal cost. The data needed for calculating marginal cost includes heat rate, fuel type and capacity, which are publically available through e-GRID [20] or other similar data sources. Fig. 1 shows an estimated dispatch curve for the PJM Interconnection, a U.S. Regional Transmission Organization whose footprint covers all or parts of thirteen states plus the District of Columbia. The dispatch curve is estimated in a manner similar to [13]. Given data on electricity demand, the dispatch curve can be utilized to determine the marginal unit in the system, as well as the market price in

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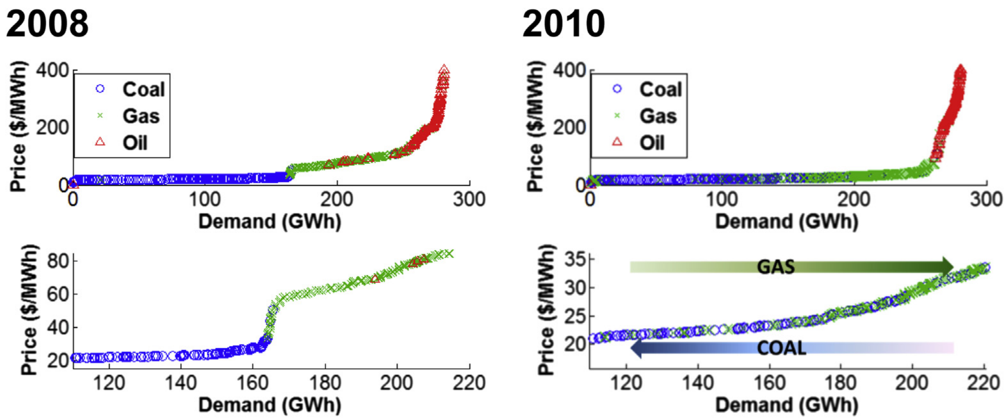

Fig. 1. Top-left: dispatch curve for PJM using the following fuel prices: coal: \$50/t, gas: \$8/MMBTU, oil: \$87/bbl. This set of prices is similar to the situation in late 2008; bottom-left: the supply curve from 120 to 220 GWh of demand. This shows the transition from coal to natural gas more clearly. Right-top: dispatch curve for PJM using the following fuel prices: coal: \$50/t, gas: \$3/MMBTU, oil: \$116/bbl. Increases in the price of coal relative to natural gas price results in a region where a mixture of coal and gas is marginal; Right-bottom: the same curve is shown for the region representing 120–220 GWh of demand. It shows how a mixture of two fuels is marginal when demand is between 120 and 200 GWh. These curves are estimated using heat rate data from eGrid [20] combined with assumptions of fuel prices. The heat content of coal and oil is assumed to be 25 MMBTU/t and 5.8 MMBTU/bbl respectively.

the absence of transmission constraints (the so-called “System Marginal Price”). However, because of the transmission constraints, both prices and marginal technologies can be potentially different at different locations within the power system. For example in PJM during the peak hours prices are much higher in eastern areas such as Philadelphia and Washington, D.C. than Western Pennsylvania and West Virginia. At such times, coal may be on the margin in the western PJM while oil is on the margin in eastern PJM.

Locational price differences induced by transmission congestion can introduce challenges in the context of policy analysis. We take as an example Pennsylvania's Act 129, which is an energy conservation and efficiency policy that requires the state's utilities to reduce their annual demand by one percent with 4.5% additional peak demand shaving.[1] By looking at the dispatch curve in Fig. 1, one can see that the slope of the supply curve is low when the demand is less than 250 GWh, and a policy analyst assessing the price impact of Act 129 would predict that the Act would not materially reduce wholesale prices in the PJM system (and, consequently, in Pennsylvania). Such an assessment would ignore important locational price differences, with two potential consequences. First, the estimated potential impacts of an efficiency policy such as Act 129 are likely to be biased downwards, since they would not capture the steeper supply curves (higher-cost generation) used in locations downstream from transmission constraints. Second, the policy analyst would not be able to estimate locational differences in price impacts and fuels utilization. These locational impacts may be important outcomes of the policy.

Fig. 1 suggests that, for a year similar to 2008, we can differentiate the technologies in the supply curve and find thresholds based on demand levels, where the marginal input fuel switches. More recently, increased unconventional natural gas production, particularly in the PJM region [21], has significantly decreased natural gas prices. Resulting shifts in relative fuel prices in the PJM region (Fig. 2), have led in some short-run substitution of coal with natural gas technologies [22], as the marginal cost of efficient combined-cycle gas plants declines to levels similar to that of coal fired plants. Therefore, the threshold defining the border between coal and natural gas becomes fuzzy, as shown in Fig. 1 for 2010. In the fuzzy region, the marginal technology is effectively fueled by a mixture of coal and natural gas. Further changes in relative fuel prices (which may be caused by additional declines in natural gas prices or increases in coal prices) will serve to widen this fuzzy region, which means that a mixture of coal and natural gas will be marginal over a wider range of load.

Here we seek to develop a model with publicly available data that can capture locational differences in technologies and fuels that are on the margin in transmission-constrained electricity systems. Our method implicitly models transmission constraints by estimating electricity price and marginal fuel at the zonal level as a function of zonal and system-level electricity demand. (Large-scale power systems are often divided into geographic “zones” for planning, pricing or other purposes; see Ref. [23].) The rest of this paper is organized as follows: A simple example which motivates our method is presented in Section 2. Our econometric model is described in Section 3. Section 4 presents the application of our method to seventeen utility zone of PJM as well as the simulation of Pennsylvania Act 129 and a carbon tax policy. Section 5 concludes the paper.

2. Motivating example

The following example shows how transmission constraints introduce complexities in building supply curves and performing policy analysis. Fig. 3 shows a simple electric system with two nodes. There is a single generator and single customer or “load” at each node. The generators are assumed to have simple linear marginal cost functions; $MC(G_1) = 5 + G_1$ for the generator at node 1, and $MC(G_2) = 10 + 2G_2$ for the generator at node 2. For the purposes of this example, we will ignore any capacity constraints on the two generators but we will assume that the transmission line connecting the two nodes has a capacity limit of 20 Megawatts (MW). If demand at node 1 in a certain hour is given by $L_1 = 30$ MWh and demand at node 2 is given by $L_2 = 35$ MWh, then total demand in the system is $L = 65$ MWh and there is no transmission congestion. The supply curve for the system is thus the vertical sum of the individual supply curves: $G = 1.5P - 10$ for $G > 5$, where $G = G_1 + G_2$ and P is the market price of electricity. At a demand of 65 MWh, we thus have $65 = 1.5P - 10$, and the market-clearing price for electricity is \$50/MWh. Under this scenario, $G_1 = 45$ MWh and $G_2 = 20$ MWh. Thus, 15 MWh of electric energy is transferred across the transmission line from node 1 to node 2. A

[1] The full text of Act 129 can be found online at http://www.puc.state.pa.us/electric/pdf/Act129/HB2200-Act129_Bill.pdf.