Web Appendix to "Incomplete Environmental Regulation, Imperfect Competition, and Emissions Leakage"

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Abstract

This appendix provides additional details and results to support the main simulation results discussed in the paper. First, details regarding how the numerical simulations where carried out under alternative assumptions about firm conduct in California's wholesale electricity market are provided. Results from simulations that assume elastic- versus perfectly inelastic- demand are summarized. Finally, a list of out-of-state generation owned and operated by California load serving entities is provided.

1 Simulation Methods

The single-stage game

The single-stage Cournot model is modified to reflect the realities of the California market. Firms' marginal costs are now assumed to be increasing with production (versus constant). Unit-level capacity constraints and transmission constraints are explicitly represented.

Supply curves for the Pacific Northwest (*i.e.* Washington and Oregon) and Southwest (*i.e.* Arizona, Nevada, New Mexico, and Utah) are constructed using dependable capacity measures and marginal costs of all generation located in these states that is not owned by California utilities. Least cost dispatch is assumed in the PNW and SW regions.[1] Generation not required to serve native load is assumed to be available for export to California, subject to transmission constraints. Transmission capacity is allocated first to firm imports, and then to the least costly out-of-state generation that is not needed to serve native load.

The competitive fringe includes all non-strategic instate generation and all non-strategic, out-of-state generation that can be accommodated by existing transmission capacity. The out-of-state units that help comprise this fringe vary from hour to hour with loads in neighboring states. In each hour, the residual demand curve faced by the strategic firms is constructed by subtracting fringe supply from California demand in that hour.

For each of three policy regimes (*i.e.* no environmental regulation, complete regulation, and incomplete regulation) 8784 hourly supply curves are constructed for each of the eleven strategic firms supplying the California market. The total capacity that the i^{th} firm has available in hour t is comprised of the in-state generation and firm imports owned by the firm, plus any out-of-state generation owned by the firm that is not required to supply native

[1] With the exception of Oregon (where the vast majority of generating capacity is hydro), all of the states surrounding California have elected not to restructure their electricity industries. Consequently, least cost dispatch in these states is a reasonable assumption.

load. These generating units are arranged in order of ascending marginal operating cost to yield a firm-specific, hour-specific step function. For simulations that assume GHG regulations (complete and incomplete), marginal costs reflect the cost of complying with the environmental regulation.

A linear function $c_{it}(q_{it})$ is fit to these firm-specific, hour-specific step functions. The vector of equilibrium production quantities $\mathbf{q}_t^* = \{q_{1t}....q_{11t}\}$ solves:

$$\max_{q_{it}} \left\{ p_{st}(q_{it}, \sum_{j \neq i}^{N} q_{jt}^*) q_{it} - c_{it}(q_{it}) - d_i \tau e_i q_{it} \right\}, i = 1..11,$$

subject to unit-level non-negativity constraints, unit-level capacity constraints and transmission constraints.

In each hour, I solve iteratively for the Cournot equilibrium. Using the GAUSS eqsolve procedure, the profit-maximizing output for the i^{th} Cournot supplier is determined conditional on the production of the other Cournot suppliers.[2] For each hour, equilibrium quantities, equilibrium emissions and electricity prices are recorded for the three regions.

The two-stage game with forward contracts

In the theoretical analysis of the two period model, it was possible to solve for $\mathbf{q}^*$ by substituting $\mathbf{q}(\mathbf{f})$ directly into [14]. In order to make the model more realistic, the simplifying assumption of constant marginal costs is released. Consequently, it becomes prohibitively difficult to solve explicitly for spot market production quantities $\mathbf{q}$ in terms of the forward positions $\mathbf{f}$.

Fortunately, the explicit function $\mathbf{q}(\mathbf{f})$ is not essential to solving the system of first order conditions that define the spot market equilibrium. Note that the system of equations that define the spot market equilibrium can be rewritten:

$$p_{st}(Q_t)\frac{\partial q_{it}}{\partial f_{it}} + q_{it}\frac{\partial p_{st}}{\partial f_{it}} - c_{it} - \tau d_i e_i \frac{\partial q_{it}}{\partial f_{it}} = 0 \tag{1}$$

The multivariate implicit function theorem allows us to solve for the matrix of partial derivatives $\mathbf{q}_t'(\mathbf{f}_t)$ without having to explicitly solve for $\mathbf{q}(\mathbf{f})$. These partial derivatives can then be substituted into the system of equations defined by (1).

The hour-specific, firm-specific marginal cost functions $C_{it}(q_{it})$ and the residual demand equation $a_t - b_t(\sum_{i=1}^{11} q_{it})$ discussed in the previous section are also used to parameterize the system of first order equations defined by [1]. The same iterative algorithm described in the previous section is used to solve this system. Equilibrium production at strategic firms $\mathbf{q}_t^*$, fringe firms, aggregate emissions $\mathbf{E}_t^*$ and electricity price p_{st}^* are computed for each hour.

[2] The algorithm begins by solving for the profit-maximizing output of the first supplier assuming that the other strategic suppliers do not produce. In the next step, the level of output at the second firm is solved for conditional on the q_1 calculated in the previous step, and assuming that $q_i = 0$ for all $i \neq 1, 2$. The algorithm proceeds, looping repeatedly through suppliers and solving for profit-maximizing output conditional on the output levels of other producers calculated in previous iterations. The process continues until no supplier can profit from changing its output levels given the output of the other strategic producers. Once equilibrium levels of output among the strategic suppliers have been identified, the corresponding equilibrium prices and emissions for the hour can be calculated.

Perfectly Competitive Spot Markets

Simulations that assume price taking behavior on the part of all electricity producers are carried out using a very similar approach. Wholesale electricity market outcomes in the Southwest and Pacific Northwest are simulated in precisely the same way as in the simulations based on the single-stage and two-stage models (*i.e.* generation not required to serve native load is assumed to be available for export to California, subject to transmission constraints). The same hourly supply curves used in the simulations that assume strategic behavior are used to simulate outcomes in a perfectly competitive California market. All firms are assumed to produce up to the point where marginal cost equals the wholesale electricity price. In each hour, I iteratively increase the wholesale price until supply equals demand in that hour.

2 Releasing the Assumption of Perfectly Inelastic Demand

The simulation models used to generate results presented in the paper assume perfectly inelastic demand. This assumption is fairly standard in electricity market simulations (Puller, 2007; Kim and Knittel, 2006). Few customers are exposed to time-varying pricing; empirically estimated own-price elasticities in electricity markets tend to be quite small. However, in as much as consumers do exhibit some demand elasticity, these results will under-estimate the effects of the policy on industry emissions (because demand reduction is not accommodated as a possible emissions abatement option).

Newcomer et al., 2008 consider U.S. electricity consumers' short run response to the introduction of a tax (or fixed permit price). They assume that consumers are exposed to real time electricity price fluctuations. Holding the level of the carbon tax fixed, they simulate emissions reductions for assumed price elasticities of demand in the range of -0.1 to -0.2. The more elastic demand, the greater the emissions reductions. In order to investigate how sensitive the simulation results presented in this paper are affected when the assumption of perfectly inelastic demand is released, some simulations are conducted that assume a downward sloping (versus vertical) demand curve. An elasticity of- 0.3 is assumed.

Tables A1 and A2 summarize results for a representative hour in which observed electricity demand was at average levels in California and surrounding states..California load, net of hydro supply, is 26,675 in this hour. To run these simulations, California electricity demand is represented by a downward sloping, linear inverse demand function. The intercept and slope parameters are those which are consistent with an own-price elasticity of -0.3 at the observed level of electricity consumption and the competitive equilibrium price under assumptions of inelastic demand and no environmental regulation ($41.97).

The simulated electricity price is significantly lower when elastic, versus perfectly inelastic, demand is assumed. Strategic firms facing a more elastic residual demand curve will have less incentive to withhold production. Emissions reductions are greater when demand response is built into the simulation model. Intuitively, this is because emissions reductions can be achieved through both a re-ordering of the dispatch and demand reductions. Incomplete regulation achieves a larger percentage of the emissions reductions achieved under complete regulation. Note that the regulation-induced increase in wholesale electricity price is similar under complete and incomplete participation. Thus, a significant fraction of the demand (and associated emissions) reductions induced by complete regulation is also observed under incomplete regulation.

References

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Newcomer, Adam, Blumsack, Seth, Apt, Jay, Lave, Lester B. & Morgan, M. Granger. (2008). 'Electricity Load and Carbon Dioxide Emissions: Effects of a Carbon Price in the Short Term', p. 179.

Puller, Steven L. (2007). 'Pricing and Firm Conduct in California's Deregulated Electricity Market', *The Review of Economics and Statistics* 89(1), 75–87.

Table A1: Summary of Equilibrium Permit Prices and Emissions Under Complete and Incomplete Regulation for a Representative Hour (One-stage Model)

	Complete Regulation		Incomplete Regulation	
	Perfectly inelastic demand	Elastic Demand	Perfectly inelastic demand	Elastic Demand
Average California electricity price ($/MWh)	$70.20	$61.40	$68.89	$59.91
Net California load (MWh)	26,675	23,588	26,675	23,825
Emissions from generation located in California (tons)	4,562	3,543	2331	1,658
Emissions from generation serving California load (tons)	12,882	11,114	13,230	11,898
Total emissions (million tons CO_2)	21,884	20,116	23,465	22,133
Total reduction (million tons CO_2)	2,459	4046	878	2,029
Total reduction (%)	10%	17%	4%	8%

Table A2: Summary of Equilibrium Permit Prices and Emissions Under Complete and Incomplete Regulation for a Representative Hour : Competitive Model

	Complete Regulation		Incomplete Regulation	
	Perfectly inelastic demand	Elastic demand	Perfectly inelastic demand	Elastic demand
Average California electricity price (\$/MWh)	\$64.58	\$58.73	\$60.90	\$56.14
Net California load	26,675	24,008	26,676	24,420
Emissions from generation located in California (tons)	4,985	3,731	2,488	1,965
Emissions from generation serving California load (tons)	12,746	11,319	13,350	12,247
Total emissions (million tons CO_2)	21,745	20,321	23,585	22,482
Total reduction (million tons CO_2)	2,558	3,982	718	1,821
Total reduction (%)	11%	16%	3%	7%

Table A3 : Out-of-state Generation owned by California entities

Plant name	State	Fuel Type	Capacity (MW)	CA Share Percent	MW
Four Corners	NM	Coal	2,140	34.6%	740
Intermountain	UT	Coal	1,810	96%	1,738
Navajo	AZ	Coal	2,250	21.2%	477
Palo Verde		Nuclear	3,867	27.4%	1,060
Reid Gardner	NV	Coal	595	29.9%	178
San Juan	NV	Coal	1,647	24.2%	399

Notes : In 2004, California utilities also owned 66% of the Mohave coal plant in Nevada. This plant was closed in 2005 due to air quality permit compliance issues. This plant is not included in simulation exercises.