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Abstract

This paper examines the implications of alternative forms of cap-and-trade regulations on the California electricity market. Specific focus is given to the implementation of a downstream form of regulation known as the first-deliverer policy. Under this policy, importers (i.e., first-deliverers) of electricity into California are responsible for the emissions associated with the power plants from which the power originated, even if those plants are physically located outside of California. We find that, absent strict non-economic barriers to changing import patterns, such policies are extremely vulnerable to reshuffling of import resources.

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1 Introduction

A central problem faced by regulators in implementing climate change policy is the limit of their regulatory jurisdiction. While greenhouse gas (GHG) emissions can be controlled locally, the damages associated with them are felt globally. Thus GHG emissions reductions are a global public good, and local restrictions, voluntarily undertaken by some jurisdictions, can be seriously undermined by offsetting emissions increases elsewhere. Perhaps the most obvious way for polluters to circumvent an environmental regulation is to relocate the regulated facility and its polluting activities to another jurisdiction. Following the literature, we refer to this physical relocation of facilities as leakage (see, for example, Fowlie (2007) and Kuik and Gerlagh (2003)). There is also the phenomenon of demand-side leakage, whereby a local regulation that depresses demand for polluting goods in one region can lead to higher quantities demanded of the goods in unregulated regions (see Felder and Rutherford (1993)). We will focus here on supply-side leakage, although we comment on the relationship between demand-side leakage and reshuffling when we discuss reshuffling below.

When differentially applied across regions, mandates and standards can lead to leakage. For example, under the Clean Air Act (CAA), more stringent and costly emission standards apply to non-attainment areas. Research has demonstrated that industrial activity declines in non-attainment areas and is at least partially displaced by growth in attainment areas, where regulatory compliance is less costly (see Greenstone (2002) and Becker and Henderson (2000)). To the extent that this displaced production emits, pollution has leaked from the heavily regulated region to the more lax region.

Market-based regulations are equally vulnerable to the problems of leakage. For example, if one jurisdiction imposes a tax on emissions or establishes a cap-and-trade system, it will be more expensive for firms to produce their pollution-intensive goods in that region. This creates an incentive for firms to move some (or all) of their production elsewhere. They may accomplish this by producing slightly less from their regulated plants and more from their unregulated plants, or by moving their particularly pollution-intensive plants out of the regulated region.

One option in the regulatory tool-kit is to focus the regulation on the point in a vertical supply chain where local regulators can have the most leverage on total emissions. Functionally, such "vertical targeting" (see Bushnell and Mansur, (2012)) can limit extra-jurisdictional emissions increases by either limiting exports of carbon producing inputs or restricting imports of carbon-intensive products. The latter case, also known as "downstream regulation" can produce a related problem that can arise when regulations are imposed at the point of purchase, but where some consumers are subject to the policies and others are not.[1] If a sufficient percentage of the products affected by a regulation already complies with it, the policy's goals can be achieved by simply reshuffling who is buying from whom (see Bushnell, Peterman and Wolfram, (2009)). In cases, such as climate change, where the location of emissions has little impact on environmental damages, reshuffling can make the environmental policy completely ineffective, as it will not alter the rate at which the favored "clean" product is produced.

The reshuffling problem is similar to the conditions that limit the effectiveness of consumer boycotts. Although a percentage of motivated customers stops buying from the boycotted source, there will be no net impact on sales or prices if there are enough other customers who are indifferent to the cause of the boycott and willing to shift to the boycotted producers. As with an ineffective boycott, reshuffling is more likely when the share of unregulated products available is larger than the share of regulated products.

Note that both reshuffling and demand-side leakage affect demand outside the regulated area. Unlike demand-side leakage, however, reshuffling does not change total equilibrium consumption (or prices or emissions) of the regulated goods. Reshuffling requires that consumers inside the regulated region perceive the clean product to be a perfect substitute for the dirty product, and so substitute all their consumption to the clean product, while consumers outside the regulated region are indifferent between consuming clean or dirty goods, and so increase their consumption of the dirty goods. There is no such perfect substitute available with demand-side leakage. In fact, there is a duality between reshuffling and demand-side leakage, since if firms are able to reshuffle completely, there need be no change in prices and therefore no demand-side reaction to the regulation. It is only to the extent that firms are unable to avoid the regulation through reshuffling that there is a real reduction in emissions in the regulated jurisdiction through new, clean supply or reduced dirty consumption. In the latter case, there could be demand-side leakage if the reduced dirty consumption in the regulated region drives down the price for the product elsewhere.

In this paper we examine this issue in the context of the California cap-and-trade market for CO2 emissions. As described below, this market is highly dependent upon imported products, particularly electricity, and is therefore vulnerable to both leakage and reshuffling, depending upon the point of regulation. The current practice is to regulate the emissions of local sources, and the emissions associated with electricity imported into the State. These regulations would be accompanied by a series of additional measures intended to limit reshuffling.

We simulate the potential effectiveness of these additional measures by building a simulation model of this market. Electricity production, transmission, and emissions are recreated for a baseline year of 2007 for which detailed data on actual market conditions are available. Once this baseline simulation is constructed, we simulate several counterfactual emissions regulations to examine the emissions and price-effects of these designs.

We find that even a modest weakening of the additional measures targeted at limiting reshuffling will greatly undermine the strictness of the emissions cap through reshuffling.

2 Regulating the California Electric Sector: A Hybrid Approach

The Global Warming Solutions Act of 2006 (AB 32) calls for California to reduce GHG emissions to 1990 levels by 2020, and assigns the responsibility for developing a strategy for meeting the 2020 target to the California Air Resources Board (CARB). The AB 32 Scoping Plan, the document that details the approach adopted by CARB, includes a cap-and-trade program.

The cap-and-trade program establishes an aggregate cap covering approximately 85 percent of the States GHG emissions, and a system of tradable emissions permits that regulated facilities may use to meet their compliance obligations. The program covers emissions for the years 2013-2020, and is partitioned into three compliance periods. Beginning in 2013, emissions obligations will be assessed on industrial facilities and first deliverers of electricity to the California grid. Emissions associated with fossil transportation fuels and retail sales of natural gas are included in 2015, at the start of the second compliance period. The third compliance period runs from 2018 through 2020.

The California initiative is proceeding in advance of the broader-based Western Climate Initiative (WCI). The WCI would link cap-and-trade programs in British Columbia, California, Manitoba, Ontario, and Quebec, allowing covered entities to participate in a regional cap-and-trade allowance market, initially encompassing large stationary sources (primarily electricity) and then expanding to include other sources, including transportation fuels in a second phase.[2] At this time, only California and Quebec intend to link programs in the first compliance period, with additional jurisdictions potentially linking in future compliance periods.

California electric utilities serve their demand with power supplied by generation facilities they own, contracts with other generators or marketers, and short-term market purchases. Some generation is located in California and additional energy is imported from other states in the Western Interconnection. Californias end-user electric demand and in-state electric generation accounts for one-fourth of the emissions included under the statewide cap. Imported electricity is a significant energy and emissions source. In 2008, imported electricity accounted for approximately one-third of electricity supplied to the California grid, and half of electric sector emissions.

Recognizing that an accurate accounting of Californias GHG footprint would need to include emissions from imported electricity, and wary of emissions leakage, the California Legislature wrote a provision into AB 32 directing CARB to account for all emissions from out-of-state electricity delivered to and consumed in California. While the most parsimonious means of achieving this objective would be to directly regulate generators of electricity used to serve the California grid, California's limited jurisdiction does not allow for the direct regulation of out-of-state generation facilities. In order to meet the statutory obligation of AB 32, CARB developed a hybrid approach to regulating the electric sector. Under the hybrid approach, the first deliverer of electricity into the California grid faces the compliance obligation for emissions. For in-state generation the facility operators are considered the first deliverers. Operators of in-state facilities report facility emissions and net generation directly to CARB. Therefore, the source (and associated emissions) of the electricity is known. First deliverers of imported electricity are the marketers and retail providers who import energy into the California grid.

One significant limitation of this approach is the uncertainty associated with which emissions factor to attribute to imported power. Due to the nature of the Western Interconnection, electricity imports do not, in general, travel directly from generation facility to the California grid. Therefore, it is generally not possible to identify the source of imported electricity with sufficient granularity to assign a specific emissions obligation. California regulators address this uncertainty of the emissions factor by providing first deliverers the option of reporting a facility-specific emissions factor associated with the energy they are importing.

CARB, however, has set a high bar for importers wishing to claim a facility-specific emissions factor. In order to claim a facility-specific emissions factor the importer must provide three pieces of documentation: evidence that the facility was operating in the same hour that the power is claimed to have been scheduled into California; evidence that the importer possesses rights to the power generated by the facility; and evidence that the importer scheduled an equivalent amount of power from the generating facilitys balancing authority area into the California grid. In many cases, first-deliverers of imported electricity will not be able to provide this level of documentation. In such cases, CARB assigns first deliverers of imported energy a default emissions factor, which is meant to represent the most likely emissions factor associated with energy generated out-of-state to meet California load, discussed in greater detail below.

Historically unspecified power has made up a substantial share of imports. In the 2008 GHG Emissions Inventory, unspecified power accounted for approximately 57 percent of emissions associated with imported electricity.[3] Because of this, the treatment of unspecified power and the value of the default emissions factor will be central to an accurate accounting of emissions from imported power.

2.1 The Default Emissions Factor

In their Interim Decision, the California Public Utilities Commission (CPUC) recommended that CARB use a regional default emission factor of 1,100 lbs/MWh to represent unspecified electricity. This emission factor was meant to loosely approximate the most likely source of marginal generation, a less efficient gas fired generator located out-of-state and within the Western Interconnection. Subsequently, CARB collaborated with the California Energy Commission (CEC), CPUC, and other WCI jurisdictions to refine this number by developing a methodology for assigning an emission factor for unspecified power that would accurately reflect the emissions associated with marginal electricity.

The WCI working group settled on a default emission factor of 961lbs/MWh, (0.428MMT/MWh) representative of a fairly clean natural gas plant. The unspecified power emission factor is calculated as a rolling three-year average of the marginal plants in the Western Interconnection, where marginal plants are defined as facilities producing at 60% of generating capacity or less. The emission factor is then calculated using Energy Information Administration (EIA) fuel and net generation data and CARB fuel-specific emission factors.

The resources assumed available for marginal dispatch are largely natural gas facilities. Baseload and renewable sources are excluded from the WCI market emission factor calculation. Baseload facilities are typically large capacity sources, such as coal, large hydro, and nuclear power, that generate electricity at costs lower than natural gas facilities. Less expensive coal, nuclear power, and hydroelectricity are assumed to be fully committed to meet utility baseload in the Western Interconnection. More expensive renewable energy is assumed to be fully contracted by electric utilities in order to meet Renewable Portfolio Standard (RPS) compliance targets.

Under cap-and-trade, the prevalence of unspecified power will be influenced by the default emission factor. First deliverers and generators with lower emission factors will wish to specify their actual emissions factor in order to minimize the carbon costs associated with their output. If the emission factor is set too low firms will have an incentive to "launder" their higher emitting resources through the market to attain the lower, unspecified, emission factor. Laundering precipitates GHG emissions leakage, a phenomenon that AB 32 explicitly directs regulators to minimize, to the extent feasible. This may be of particular concern, due to the fact that many of the high emitting resources that first deliverers could seek to launder are baseload or otherwise operating at a high fraction of capacity. As a point of reference, the California Energy Almanac reports that in 2009 more than 20,000 GWhs of specified coal power were imported into California. If all of these resources were to somehow become unspecified, it would result in approximately 10 mmTons of paper emissions reductions. That quantity is roughly equivalent to the entire 2012 annual allocation of emissions allowances to the oil and gas extraction sector, the second largest industrial sector regulated under the program.

2.2 Additional Rules Limiting Emissions Leakage

The default emissions factor is not the only potential conduit for emissions leakage. Another undesirable behavior that stems from the first deliverer approach is reshuffling. Reshuffling could occur if low or zero GHG resources, which currently serve out-of-state baseload, were reassigned to California and higher emitting out-of-state resources, which currently serve California, were reassigned to serve the out-of-state baseload. As with laundering, significant reshuffling could undermine the integrity of the program. However, unlike laundering, reshuffling cannot be addressed by correctly setting the default emissions factor.

To address concerns about laundering and reshuffling, and in recognition of the fact that it would be very difficult for CARB to identify each instance of laundering or reshuffling, CARB has proposed an explicit prohibition of the behaviors. The prohibition works by requiring the individual responsible for reporting GHG emissions for each compliance entity to sign an attestation, under penalty of perjury, that they have not engaged in any scheme or artifice to claim GHG reductions that are not real. This approach, with a lack of detail defining exactly what reshuffling was, has been extremely controversial. On August 8th, Federal Energy Regulatory Commissioner Phillip Moeller issued an open letter to California Governor Jerry Brown expressing concern over the " uncertainty and great concern among entities selling into California" caused by "failing to define resource shuffling, but nevertheless prohibiting it." On August 16th, CARB Chair Mary Nichols responded that the agency would suspend enforcement of the provision for at least 18 months to help avoid any negative impact on electricity supplies to California.

3 Analysis of Cap-and-Trade Design

Our focus is on the specific design of the cap-and-trade mechanism, and its impact on the operation of electricity markets. Therefore the focus here is on a "short-term" time frame. We base our analysis upon actual market data drawn from the year 2007, and look at the counter-factual question of how those markets would have functioned under a cap-and-trade regime. In this sense the work follows in the spirit of Fowlie (2009), who also studies the potential for leakage from a California-only market, and also that of Bushnell and Chen (2008) who deploy similar techniques to examine allowance allocation policies in a purely source-based allowance trading regime.

In a fashion similar to Zhao, et al., (2010), we formulate the joint equilibrium outcomes of the emissions and electricity market as a linear-complementarity problem. Unlike Zhao, et al. (2010), and Fowlie, et al. (2010) we do not study the implications for updating policies on plant investment or retirements. In this sense our model, while dynamic, is focused on short-run operational decisions.

Our study differs from previous work in several important ways. While Fowlie (2009) models portions of the western electricity market, we model the emissions credit prices as endogenous to the cap-and-trade market. This is central to our work given our focus on the endogenous impact of allocation policies on permit prices. Second, we explicitly model the first-deliverer aspects of the AB 32 policies. To our knowledge, this is the first empirical study directed at this topic. Previous work examining the impacts of allocation have either taken a general equilibrium approach (Bohringer and Lange (2005), Sterner and Muller (2008), Fischer and Fox (2008), or applied more complex formulations to stylized market data (Chen et al., 2011, Zhao, et al., 2010, Neuhoff, et al., 2006). Except Chen et al. (2011), all these papers, including Bushnell and Chen (2011), which is closely related to this one, model a purely source-based system.

3.1 Model

In this section, we first describe our equilibrium model and then discuss how we apply data from various sources to arrive at our calculations.

We assume here that firms act in a manner consistent with perfect competition with regards to both the electricity and emissions permit markets.[4] As such, the solution stemming from a perfectly competitive market is equivalent to the solution of a social planner's problem of maximizing total welfare.

The key variables and parameters of the model are grouped according to four important indices: the origin, destination, plant, and time period of production. The total production of plant p from location i exported to location j, at time t is represented by $q_{p,i,j,t}$. Production costs $C_p(q_{p,t})$, vary by firm, technology, and location, and are constant for each plant and are unchanging over time.

$$C_p(q_{p,t}) = c_p q_{p,t}$$

where $q_{p,t} = \sum_j q_{p,i,j,t}$. Total emissions by firm and technology are determined by a constant emissions rate e_p and denoted $e_p(q_{p,t}) = e_p * q_{p,t}$.

Wholesale electricity is assumed to be a homogenous commodity for purposes of setting wholesale prices, although prices are assumed to vary by location subject to transmission constraints as described below. For each time period $t \in \{0, ..., T\}$, a perfectly competitive market outcome is obtained by solving the following welfare maximizing problem:

$$\int_0^{Q_{j,t}} P_{j,t}(Q)dQ - \sum_p C_p(q_{p,t}), \tag{1}$$

where $P_{j,t}(Q)$ gives the power prices in location j in period t, and $Q_{j,t} = \sum_{p,i} q_{p,i,j,t}$. The output $q_{p,t}$ is further limited by its capacity: $q_{p,t} \leq \bar{Q}_p$. The electricity sales are also subject to cap-and-trade regulation that will also be discussed below.

3.2 First-Deliverer Enforcement

As discussed above, one mechanism that can at least partially combat leakage is regulating emissions from imports by applying the emissions obligation on first deliverers of electricity to the grid. In the case of imported power, this requires importers of power to acquire emissions allowances and offsets equal to the measured or estimated emissions of the sources from which the imported power is claimed to originate. In addition, power plants within California will be required to cover their emissions with compliance instruments, following a more conventional "source-based" paradigm.

We model this hybrid design by establishing the cap constraint in terms of both instate emissions and emissions from sources "exporting" power into California. Therefore, emissions from electricity production falls into two categories, that within the region covered by the emissions cap and that outside the reach of the regulation. The following constraint is imposed to model the cap-and-trade regulation:

$$\sum_{p,(i,j) \in REG,t} e_p q_{p,i,j,t} \leq CAP, \tag{2}$$

where the parameter CAP denotes the total cap in the cap-and-trade regulation, and the set REG represents those pairs of "origins" and "destinations" for electricity sales that are subject to the cap-and-trade regulation. If the source-based is considered, REG refers to the pairs with which the origin region i is California.

3.3 Additional Regulatory Measures

One challenge we faced when modeling the Western Electricity Coordinating Council (WECC) market is the lack of information about the power plants that are not required to report in the Environmental Protection Agencys Continuous Emission Monitoring System (CEMS). We therefore assigned a zero emission rate to those units since historically they are dominated by renewables and hydro facilities. Because these units are assigned with a zero emission rate, allowing them to freely determine their sale destination is likely to create an unrealistic re-shuffling opportunity, and thereby bias the effects of cap-and-trade regulation. We therefore assume that the power sales of those "NONCEMS" units are not changed in response to the cap-and-trade regulation and fix their sales $q_{p,i,j,t}$ at their levels prior to cap-and-trade regulation. To examine the sensitivity of this assumption on the market outcomes, we later relax it by allowing 10% of the NONCMES outputs to optimize their destination under the cap-and-trade regulation.

Another modeling detail that also requires additional explanation is the treatment of existing or legacy contracts. Historically, some facilities outside of California are partially owned by the California utilities. Therefore, some percentages of their output is designated to be imported into the corresponding utility's service territory by conditions specified in these contracts. Assuming that these contracts are maintained, no accounting for them would inflate the flexibility of the market and overestimate the re-shuffling effects. We treat contractual obligations as applying to percentages of a plant's output. With this added constraint, the only way a California utility can reduce its emissions from a contracted plant is through a reduction in the overall output of that plant. Again, this constraint only applies if we assume such contracts are maintained through their current lifetimes. We explore the implications of this assumption in later sections.

Finally, we follow the proposals considered by CARB to apply a default emission rate to account for the emissions from the unspecified imports. This arises from a situation in which the emissions of the imports delivered to the California pool-typed markets cannot be unambiguously identified. This regulatory measure allows those plants with an emission rate that is above the default emission rate to circumvent high emissions costs when selling their power into the California markets.

3.4 Transmission Network Management

We assume that the transmission network is managed efficiently in a manner that produces results equivalent to those reached through centralized locational marginal pricing (LMP). For our purposes this means that the transmission network is utilized to efficiently arbitrage price differences across locations, subject to the limitations of the transmission network. Such arbitrage could be achieved through either bilateral transactions or a more centralized operation of the network. For now we simply assume that this arbitrage condition is achieved.

Mathematically, we adopt an approach utilized by Metzler,et al. (2003), to represent the arbitrage conditions as another set of constraints of the market equilibrium. Under the assumptions of a direct-current (DC) load-flow model, the transmission 'flow' induced by a marginal injection of power at location l can be represented by a power transfer distribution factor, $PTDF_{lk}$, which maps injections at locations, l, to flows over individual transmission paths k. Within this framework, the arbitrage condition will implicitly inject and consume power, $y_{l,t}$, to maximize available and feasible arbitrage profits as defined by

$$\sum_{l \neq h} (p_{h,t} - p_{l,t})\, y_{l,t}.$$

In the above arbitrage equation, the location h is the arbitrarily assigned "hub" location from which all relative transmission flows are defined. Thus an injection of power, $y_{l,t} \geq 0$, at location l is assumed to be withdrawn at h. This arbitrage condition is subject to the flow limits on the transmission network, particularly the line capacities, T_k:

$$-\overline{T}_k \leq PTDF_{l,k} \cdot y_{l,t} \leq \overline{T}_k.$$

4 Data Sources and Assumptions

We utilize detailed hourly load and production data for all major fossil-fired and nuclear generation sources in the western U.S. Our primary sources are FERC form 714, which provides hourly system demand for major utility control areas, and the EPA Continuous Emission Monitoring System (CEMS) data, which provide hourly output for all major fossil-fired power plants. The CEMS data cover all major utility level sources of CO2, but we do not model output from nuclear, combined-heat and power, wind, solar, or hydro sources.

These hourly data are aggregated by region to develop the "demand" in the simulation model. As discussed below, for purposes of the cap-and-trade simulations, the relevant demand is in fact the residual demand; the demand that is left after applying the output from non-CEMS plants. These data are combined with cost data to produce cost and emissions estimates for each of the 419 generation units in the CEMS database.

These data are then combined to create demand profiles and supply functions for periods in the simulation. Although hourly data are available, for computational reasons we aggregate these data into representative time periods. There are 20 such periods for each of the four seasons, yielding 80 explicitly modeled time periods. As California policy was the original focus of this work, the aggregation of hourly data was based upon a sorting of the California residual demand. California aggregate production was sorted into 20 bins based upon equal MW spreads between the minimum and maximum production levels observed in the 2007 sample year. A time period in the simulation therefore is based upon the mean of the relevant market data for all actual 2007 data that fall within the bounds of each bin.

The number of season-hour observations in each bin is therefore unbalanced, there are relatively few observations in the highest and lowest production levels, and more closer to the median levels. The demand levels used in the simulation are then based upon the mean production levels observed in each bin. In order to calculate aggregate emissions, the resulting outputs for each *simulated* demand level was multiplied by the number of *actual* market hours used to produce the input for that simulated demand level. For example, every actual hour (there were 54) during Spring 2007 in which California residual demand fell between 6949 and 7446 MW were combined into a single representative hour for simulation purposes. The resulting emissions from this hour were then multiplied by 54 to generate an annualized equivalent total level of emissions.

In the following sub-sections, we describe further the assumptions and functional forms utilized in the simulation.

4.1 Market Demand

Aggregate demand is taken from FERC form 714, which provides hourly total end-use consumption by control-area and is aggregated to the North American Electric Reliability Commission (NERC) sub-region level. As described below a large portion of this demand is served by generation with effectively no CO2 emissions, such as nuclear and hydro sources. This generation needs to be netted out from total demand to produce a residual demand to be met by GHG producing fossil sources.

End-use consumption in each sub-region is represented by the demand function $Q_{l,t} = \alpha_{l,t} - \beta_l p_{l,t}$, yielding an inverse demand curve defined as

$$p_{lt} = \frac{\alpha_{l,t} - \sum_{i,j} q_{i,j,t} - y_{i,t}}{\beta_l}$$

where $y_{i,t}$ is the aggregate net transmission flow into location l. The intercept of the demand function is based upon the actual production levels in each location calculated

Table 1: Derated Generation Capacity (MW) by Region and Fuel Type

Region	Coal	CCGT	Gas St	Gas CT	Oil	Total
CA	0	10823	12430	2728	496	26477
IM	1405					1405
NW	9716	4506	610	1235		16068
RM	5596	1476	96	1659		8826
SW	8652	11623	1751	1042		23068
Total	25369	28429	14887	6664	496	75845

Table 2: Energy Production (GWh) by Region and Fuel Type

Region	Coal	CCGT	Gas St	Gas CT	Oil	Non-CEMS
CA	0	66607	12898	1836	144	117766
IM	14407	0	0	0	0	0
NW	84321	24017	1884	1387	0	113553
RM	49534	9420	10	2236	0	1529
SW	75292	51184	2937	1374	0	63286
Total	223554	151228	17729	6833	144	296134

as described above. In other words, we model a linear demand curve that passes through the observed price-quantity pairs for each period. As electricity is an extremely inelastic product, we utilize an extremely low value for the slopes of this demand curve. For each region, the regional slope of the demand curve is set so that the median elasticity in each region is -.05.[5]

4.2 Hydro, Renewable and other Generation

Generation capacity and annual energy production for each of our regions is reported by technology type in Tables 1 and 2. We lack data on the hourly production quantities for the production from renewable resources, hydro-electric resources, combined heat and power, and small thermal resources that comprise the "non-CEMS" category. By construction, the aggregate production from these resources will be the difference between market demand in a given hour, and the amount of generation from large thermal (CEMS) units in that hour. In effect we are assuming that, under our CO2 regulation counter-factual, the operations of non-modeled generation (e.g., renewable and hydro) plants would not have changed. This is equivalent to assuming that compliance with the CO2 reduction goals of a cap-and-trade program will be achieved through the reallocation of production within the set of modeled plants. We believe that this is a reasonable assumption for two reasons. First the vast majority of the CO2 emissions from this sector come from these modeled resources. Indeed, data availability is tied to emissions levels since the data are reported through environmental compliance to existing regulations. Second, the total production from "clean" sources is unlikely to change in the short-run. The production of low carbon electricity is driven by natural resource availability (e.g., rain, wind, solar) or, in the case of combined heat and power (CHP), to non-electricity production decisions. The economics of production are such that these sources are already producing all the power they can, even without additional CO2 regulation. To a first-order, short-run emissions reductions will have to come either from shifting production among conventional sources, a reduction in end-use electricity demand, or through substitution with unregulated imports, *i.e.*, leakage or reshuffling.[6]

4.3 Fossil-Fired Generation Costs and Emissions

We explicitly model the major fossil-fired thermal units in each electric system. Because of the legacy of cost-of-service regulation, relatively reliable data on the production costs of thermal generation units are available. The cost of fuel comprises the major component of the marginal cost of thermal generation. The marginal cost of a modeled generation unit is estimated to be the sum of its direct fuel, CO2, and variable operation and maintenance (VO&M) costs. Fuel costs can be calculated by multiplying the price of fuel, which varies by region, by a unit's 'heat rate,' a measure of its fuel-efficiency.

The capacity of a generating unit is reduced to reflect the probability of a forced outage of each unit. The available capacity of generation unit i, is taken to be $(1 - fof_i) * cap_i$, where cap_i is the summer-rated capacity of the unit and fof_i is the forced outage factor reflecting the probability of the unit being completely down at any given time.[7] Unit forced outage factors are taken from the generator availability data system (GADS) data that are collected by the North American Reliability Councils. These data aggregate generator outage performance by technology, age, and region.

Generation marginal costs are derived from the costs of fuel and variable operating and maintenance costs for each unit in our sample. Platts provides a unit average heat-rate for each of these units. These heat-rates are multiplied by a regional average fuel cost for each fuel and region, also taken from Platts. Marginal cost of each plant p is therefore constant:

Table 3: Average Emissions Rates (Tons/MWh) by Region and Fuel Type

Region	Coal	CCGT	Gas St	Gas CT	Oil
CA	NA	0.425	0.583	0.822	0.837
IM	1.011	NA	NA	NA	NA
NW	1.093	0.437	0.639	0.826	NA
RM	1.126	0.420	0.792	0.828	NA
SW	1.081	0.398	0.627	0.856	NA

$$C_p(q^i_{p,t}) = c_p q_{p,t}.$$

Emissions Rates

Emissions rates, measured as tons CO2/MWh, are based upon the fuel-efficiency (heat-rate) of a plant and the CO2 intensity of the fuel burned by that plant. The average emissions rates of all facilities are summarized by region in Table 3.

4.4 Transmission Network

Our regional markets are highly aggregated geographically. The region we model is the electricity market contained within the U.S. portion of the Western Electricity Coordinating Council (WECC). The WECC is the organization responsible for coordinating the planning investment, and general operating procedures of electricity networks in most states west of the Mississippi. The multiple sub-networks, or control areas, contained within this region are aggregated into four "sub-regions." Between (and within) these regions are over 50 major transmission interfaces, or paths. Due to both computational and data considerations, we have aggregated this network into a simplified 5 region network consisting primarily of the 4 major subregions.[8] Figure 1 illustrates the areas covered by these regions. The states in white, plus California, constitute the US participants in the WECC.

Given the aggregated level of the network, we model the relative impedance of each set of major pathways as roughly inverse to their voltage levels. The network connecting AZNM and the NWPP to CA is higher voltage (500 KV) than the predominantly 345 KV network connecting the other regions. For our purposes, we assume that these lower voltage paths yield 5/3 the impedance of the direct paths to CA. Flow capacities over these interfaces are based upon WECC data, and aggregate the available capacities of aggregate transmission paths between regions.

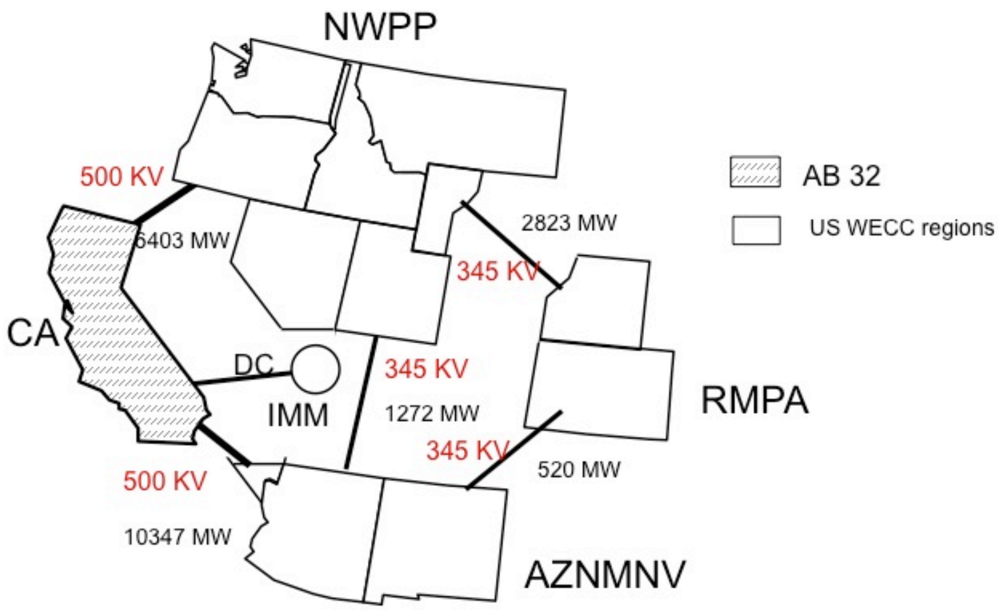

Figure 1: Western Regional Network and Cap-and-Trade Regions

5 Results

In this section we discuss the implications of different degrees of enforcement of various anti-reshuffling elements in the market, as well as contrast these results to alternative hypothetical cap-and-trade designs. We begin with a discussion of the baseline simulation. The impacts of the regulation are based upon changes from this baseline, no-cap scenario to the counter-factual simulations with various forms of the regulation.

5.1 Baseline Simulations

For the baseline year of 2007 we first simulate production in the WECC to establish a baseline level of production, emissions, and emissions associated with imports into California. Figure 2 summarizes energy production and the associated emissions from the baseline run and from the actual CEMS data. The model assumptions manage to recreate aggregate baseline emissions by source reasonably accurately. Total WECC-wide emissions from the baseline simulation are 345 mmTons compared to 341 tons in the CEMS data. Baseline emissions in each region are within 7% of baseline in each region.

For an evaluation of the first-deliverer elements of the regulation, it is necessary to establish a baseline level not only of emissions *sources* but of emissions based upon *consumption*. This means simulating the pair-wise matching of specific destinations to the production from each power plant. It is important to recognize that this matching of sources to consumption does not affect the overall power-flow or any other constraint associated with the physical production, which is simulated based upon an assumption of social-welfare maximization. The matching just serves to establish baseline estimates of the emissions associated with consumption in different regions.

We begin by applying several restrictions from known contractual and ownership relationships to California power. We focused on the relationships between California Load Serving Entities (LSE) and coal facilities located in other regions of the WECC using information provided to us from E3 consulting. These historic relationships are summarized in Table 4. The baseline model requires that these production percentages be delivered into California from each of these facilities. Otherwise, the model finds the optimal dispatch and assigns destinations without any additional constraints. In the case of a baseline simulation, absent any costs associated with emissions, there are multiple solutions to this matching of sources and destinations. Our simulation produced emissions associated with California consumption of around 108 mmTons, which is close to the values given in the 2007 GHG inventory calculations from CARB.

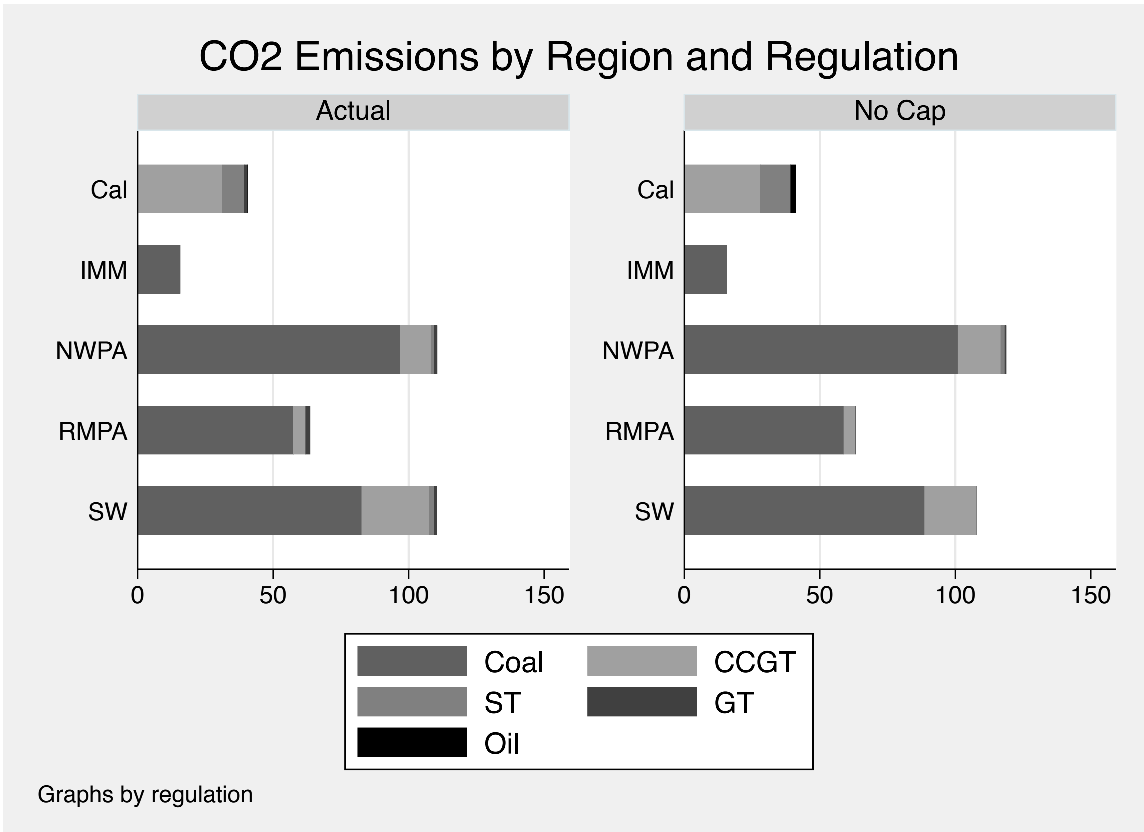

Figure 2: Actual Emissions and Simulation Results

Table 4: Energy (GWh) and Emissions (mmTons) Consumed in CA.

Plant	Units	Location	Fuel Type	CA Share	Contract?
Boardman	1	OR	Coal	23.5%	Yes
Four Corners	4 & 5	NM	Coal	48.0%	NA
Intermountain	1 & 2	UT	Coal	78.9%	No
Navajo Station	1- 3	AZ	Coal	21.2%	Yes
Reid Gardner	4	NV	Coal	67.8%	Yes
San Juan	3	NM	Coal	41.8%	No
San Juan	4	NM	Coal	38.7%	No
Bonaza	1	UT	Coal	26 MW	Yes
Hunter	2	UT	Coal	26 MW	Yes

Table 5: Energy (GWh) and Emissions (mmTons) Consumed in CA.

Source	Energy	Emissions
Coal	53210	61.99
CCGT	73414	33.66
Gas St.	20922	11.43
Gas CT	473	0.28
Oil	2195	1.84
Hydro/Nuke/other	134194	0
Totals	284409	109.2

Table 5 summarizes the sources of power consumed in California under our baseline simulation. Note that, beyond Table 4 we do not have access to further detailed matching data so, unlike with source emissions, we are unable to compare the baseline to actual observations. The Four Corners facilities are included in the baseline - as they were providing power into CA during 2007 - but have since been divested and are therefore not included in the restrictions to first-deliverer sources described below.

5.2 Cap-and-Trade Results

Having established baseline levels of imports into California, we simulate several alternative implementations of a cap-and-trade regime on the California market. The alternative scenarios include the following.

- A source-based regulation applied only to California sources
- A source-based regulation applied to California sources, with first-deliverer measures applied to imports into California. One dimension in which the first-deliverer policy may vary is in the assumed emissions (default) of 'generic' power imported through an exchange-based market or other transactions. We examined several alternatives for this default rate, and report here the results for 428 tons/GWh, the current practice, and for 1000 tons/GWh, roughly the emissions rate of an efficient coal plant. In addition, we model three alternative additional restrictions on the first-deliverer rules.
  - Historic imports from contracted and owned coal facilities (except Four Corners) and non-CEMS sources must be maintained at the same (baseline) level.

Table 6: Summary of Results with 15% Reduction in CO2

Outcome	Region	No Cap	Source Based Cap	First Del. 428 Default	First Del. 1000 Default	WECC wide cap
Permit Price		-	12.77	0.00	0.00	35.26
	Cal	41.17	35.00	41.17	41.17	38.83
Emissions mmTons	NW	118.78	121.51	118.78	118.78	117.58
	SW	107.89	110.20	107.89	107.89	96.00
	RM	63.07	63.35	63.07	63.07	62.32
	IM	15.74	15.74	15.74	15.74	15.57
	Total	346.65	345.80	346.65	346.65	330.45
	Cal	61.63	66.28	61.63	61.63	80.05
Elec. Prices Avg. $/MWh)	NW	68.32	75.57	68.32	68.32	88.74
	SW	54.93	56.55	54.93	54.93	71.35
	RM	60.16	63.8	60.16	60.16	78.49
	IM	59.32	61.77	59.32	59.32	63.30

- Same as above except imports from contracted coal facilities are not required (but are from owned coal facilties).
- Same as above plus imports of non-CEMS production from the Northwest are allowed to increase by 10% and credited with the Bonneville Power Authority average emissions rate of only 80 tons/GWh.

We simulate both a 15% and a 25% reduction in California utility power-sector emissions from 2007 baseline levels. In the case of a source-based regulation, this means a reduction from California utility sources from 41.17 mmTons to around 35 mmTons, or 30.9 mmTons, respectively. In the case of the first-deliverer scenarios, this implies a reduction from 108 mmTons (including the 41.17 from California sources) to a total of about 92 mmTons or 81 mmTons, respectively. The results for a 15% reduction are summarized in Table 6.

The most obvious and significant result is that none of the California regulations has much of an impact on WECC total emissions. The source-based California cap produces an allowance price of just under $13 a ton, but almost all of the 6 mmTon reduction in California is offset by increases in emissions in the other WECC regions. This is the standard leakage result. The first-deliverer regulations avoid this leakage, but compliance with the cap is possible through other mechanisms (discussed below) that

Table 7: Summary of Results with 25% Reduction in CO2

Outcome	Region	No Cap	Source Based Cap	First Del. 428 Default	First Del. 1000 Default	WECC wide cap
Permit Price		-	21.00	43.14	48.96	40.51
	Cal	41.17	30.88	36.64	35.84	39.40
Emissions	NW	118.78	123.48	120.24	120.60	116.56
mmTons	SW	107.89	111.55	108.77	109.59	86.43
	RM	63.07	63.74	63.06	63.08	61.52
	IM	15.74	15.74	14.97	15.74	15.74
	Total	346.65	345.39	343.68	344.85	319.65
	Cal	61.63	69.35	86.2	82.91	83.08
Elec. Prices	NW	68.32	80.2	73.43	74.15	91.34
Avg. $/MWh)	SW	54.93	57.22	53.95	55.94	74.83
	RM	60.16	65.89	61.89	63.08	81.82
	IM	59.32	62.27	59.96	61.23	63.36

require *no change* in production from any sources, and therefore produce a zero carbon price. The hypothetical WECC-wide cap, which by assumption would suffer no leakage, produces a "true" reduction of 16 mmTons, with a resulting allowance price of $35.26.

When the reductions are forced to a higher level of 25% of the 2007 baseline, more significant changes emerge. (See Table 7.) The first-deliverer regulations now produce a non-zero allowance price and some reductions in output. The most stringent version of the first-deliverer regulation, assuming a default emissions rate of 1000 tons/KWh, produces the largest WECC-wide reductions, but this is still a relatively modest savings of around 2 mmTons from production stemming from a "reduction" of carbon associated with California consumption of around 27 mmTons. By contrast, a WECC-wide cap with a goal of 27 mmTons reduction would produce an allowance price of $40.51.

5.3 First-deliverer Policy Variants

It may at first seem striking that the application of the cap to imported power in California has such limited impact on regional emissions. In order to decompose the changes behind these results, we now turn to the matching of sources to consumption that is fundamental to the first-deliverer paradigm. Figure 3 summarizes the location of the consumption of the power associated with its production for the case of a 15% reduction in California consumption-based emissions. Under the assumption that default emissions are 428 tons/GWh, a substantial amount of the baseline coal energy (all that is not under contract) is imported as default energy, which is treated as if its emissions were quite a bit lower than their true values. When instead the default is increased to 1000 tons/GWh, it is no longer economic to import coal (or anything else) and claim the default rate. Imports are instead identified from specific sources, but those sources shift from coal in the baseline to combined cycle gas sources in the capped case.

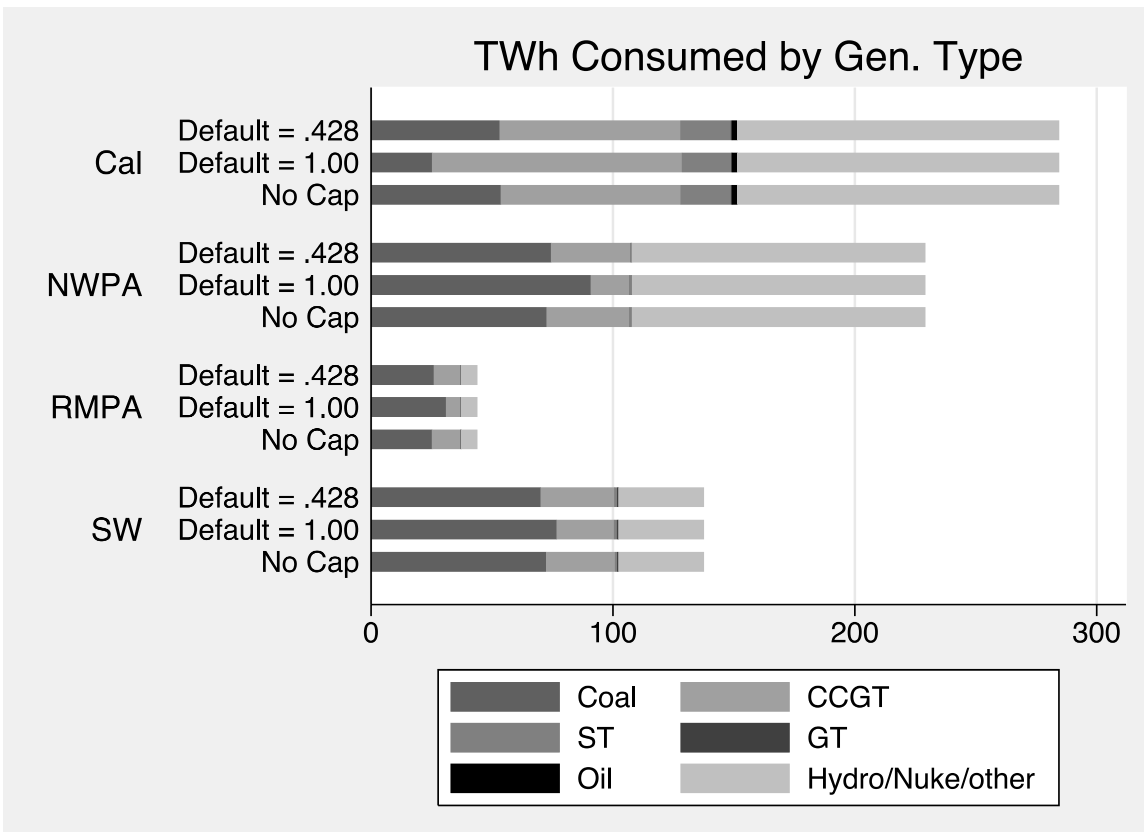

Figure 3: Consumption of Power with 15% reduction in CA Cap

The regulations have more impact when a 25% reduction is assumed for the power sector, as Figure 4 illustrates. Because the cap is binding, there is some reduction of generation from the dirtiest sources within California. The largest effects are still from imports being claimed under the default (see 428 default) and from reshuffling of sources when the default is set to 1000.

These results illustrate the nature of the problem of regulating consumption from ex-

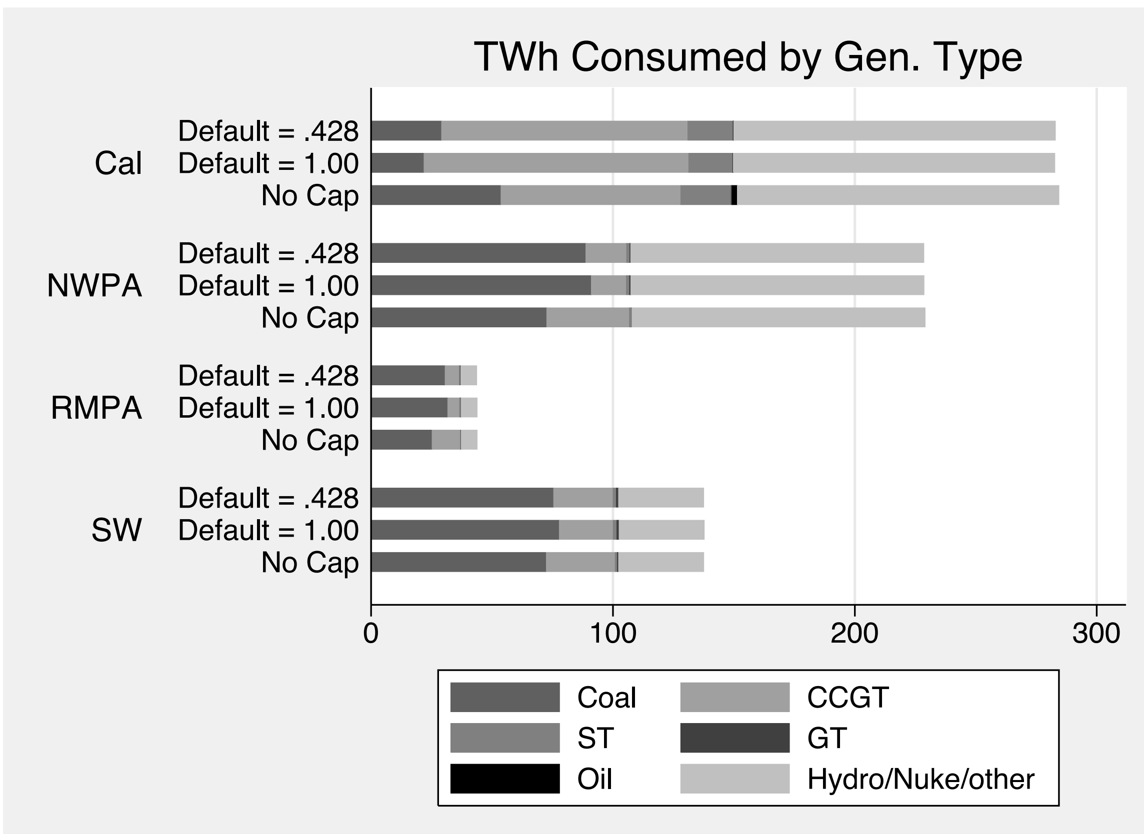

Figure 4: Consumption of Power with 25% reduction in CA Cap

Table 8: "Excess" Emissions (mmTons) due to Default Emissions Factor.

Regulation	428	1000
Baseline	5.64	.19
No Contracts	7.84	.37
10% BPA Imports	21.19	1.04

ternal sources. There are two mechanisms for circumventing the spirit of this regulation. First firms can "launder" their imports by claiming the default rate for non-contracted sources. The extent to which this is possible depends upon how firmly other restrictions are enforced. The results above assume relatively strict enforcement of anti-reshuffling rules. Namely, it is assumed that firms cannot claim default values for imports from coal sources owned by or under contract to serve LSEs in California, and that no additional imports from non-CEMS sources are possible. As we relax the assumptions about these restrictions, the amount of power that can be claimed under the default increases. Table 8 illustrates this phenomenon for the case of a 25% reduction of the California cap. This table summarizes the total amount of apparent emissions savings from sources "consumed" in California but originating from external sources that can take advantage of the default rate (e.g., non-contracted sources). Under strict enforcement of existing contracts, emissions from imports are roughly 6 mmTons higher than they appear on paper due to lower default emissions rates. As the amount of external power eligible for the default rate increases, so do the savings from doing so. When all contracted coal plants are "abandoned" as sources - and are assumed to instead sell generic power - the savings from a 428 tons/GWh default rises to just under 8 mmTons.

Claiming power under a relatively clean "default" rate is only one mechanism through which compliance can yield little true emissions reductions. We now focus on a more strict default rate of 1000 tons/GWh. In this more strict case, the enforcement of the additional rules becomes significant. In general, even a modest relaxation of either the coal or existing hydro contract provisions has a strong influence on the impact of the cap. As the requirement to import from contracted coal plants is relaxed, permit prices under the 25% reduction case drop from \$48/ton to under \$21/ton. As Figure 5 illustrates, this is due to the reduction in coal imports into California. When imports from non-CEMS (e.g., hydro) resources are allowed to increase from the baseline by up to 10%, the price drops to zero. As seen in Figure 5, the amount of non-CEMS energy consumed in California increases under this scenario, and the amount of non-CEMS energy consumed in the Northwest decreases. Imports of combined cycle gas, with emissions around .45 tons/MWh, are being exchanged for imports rated at .08 tons/MWh, the BPA default rate. This increase in BPA sourced imports, combined with a reduction of coal imports relative to the base case, allows for compliance with a consumption based cap in California without altering the physical dispatch of resources in the WECC as a whole.

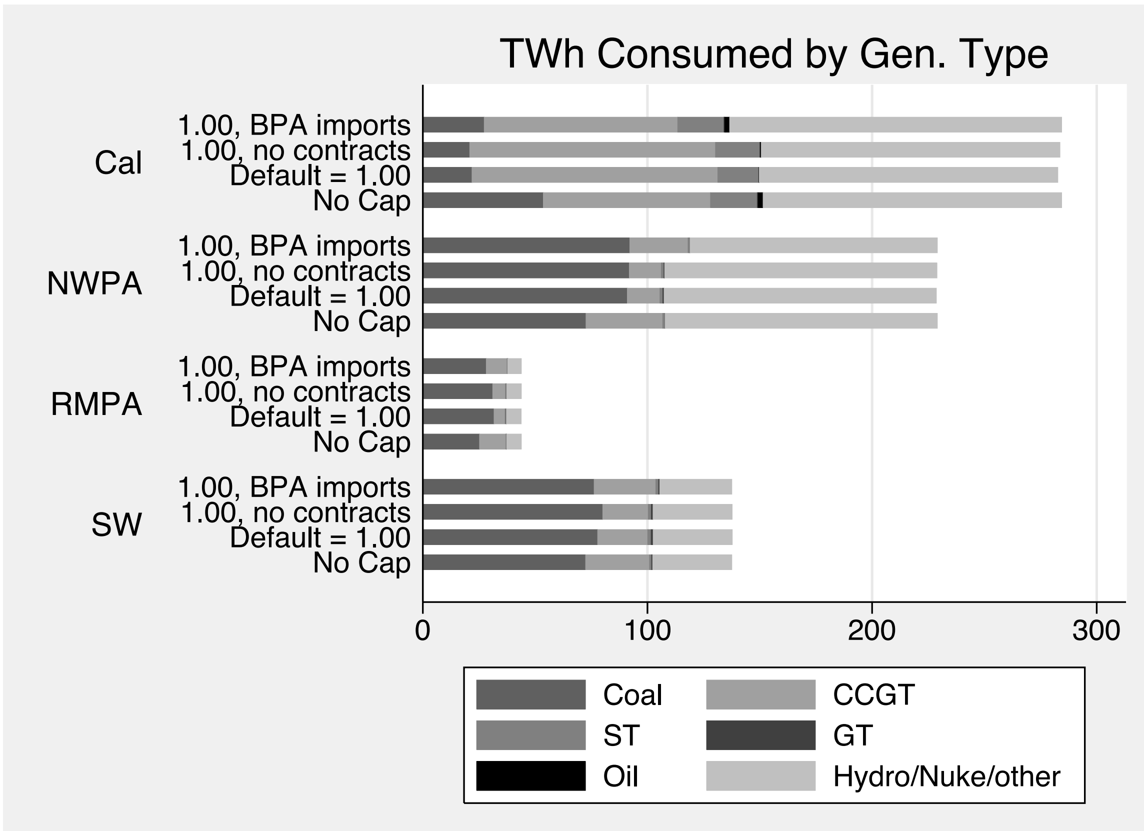

Figure 5: Enforcement of Anti-Shuffling Provisions

6 Conclusion

In this paper we analyze the impact of various forms of restrictions on greenhouse gases related to Californias electricity consumption. We formulate a baseline electricity market based upon 2007 operations in the Western Electricity Coordinating Council (WECC) region. We then simulate the impacts of placing a limit (or cap) on the GHG emissions from plants either located inside California or producing power that, at least nominally, is serving California consumers.

From an environmental standpoint, the results are not encouraging. Our previous work and research performed by others had indicated a strong vulnerability to leakage under a conventional source-based regulatory system. The simulations here are consistent with those findings. Capping California sources reduces emissions within the state, but also leads to increased imports and therefore emissions from outside California. It was a fear of such an outcome that motivated the first-deliverer design. The rules associated with such an approach are necessarily complex and a wide variety of options exist. We study several of the most likely variants of the first-deliverer system and find that, at least for reduction goals of 15% to 20%, they are unlikely to be more effective than a source-based system.

There is widespread opportunity for two mechanisms to undermine the effectiveness of a first-deliverer approach. The first mechanism allows firms to import power as "generic" power that is assigned a default emissions rate. The level of this default rate will determine the incentive to claim power as generic or as originating from a specific source. When the default rate is set, as is currently the case, at the relatively low level of .428 tons/MWh, there is a strong incentive for importers to claim any power dirtier than that default as generic. There is large scope for this activity, enough to easily comply with a goal of 15% emissions reductions without actually changing either the sources or destinations of power. The only change is the relabeling of imported power to unspecified, and the concurrent reduction in emissions associated with that relabeling. With a more aggressive reduction target of 25% simply relabeling existing imports is insufficient to meet the cap goals, and further adjustments to production become necessary.

When the default level is instead set at a more conservative 1 ton/MWh, (roughly that of an efficient coal plant) the incentive to claim imports as generic is largely eliminated. There is little advantage to relabeling imports. This does create an incentive for firms to exploit a second mechanism, however, reshuffling. The full extent of reshuffling will depend also upon several "soft" factors, including any impact of enforcement of CARB's prohibition included in the cap-and-trade reporting requirements, as described above. Other soft factors that might reduce reshuffling include the reluctance of non-California utilities to be seen as increasing their carbon footprint by taking on power abandoned by California buyers.

Because the effectiveness of the prohibition is somewhat uncertain, we consider several scenarios meant to represent varying degrees of prohibition. One scenario would prevent firms from claiming imports from existing hydro or renewable resources. Another scenario would require that firms currently with ownership or contract stakes in operating coal facilities to continue to be responsible for their proportional share of the emissions from those facilities, whether they nominally buy power from those plants or not. This amounts to a requirement to continue buying power from plants under contract or owned by a California LSE.

When the prohibition is applied as envisioned, and reshuffling is fully eliminated, the first-deliverer rules do result in some relatively modest real reductions in WECC-wide emissions. For example, under an assumed 1 ton/MWh default emissions rate and a cap that requires California electric sector emissions to be reduced by 25%, emissions allowance prices reach 48$ per ton. Reductions from the WECC overall are about 3 mmTons, however, only about 10% of the nominal 27 mmTon reduction required by the cap.

While we have tried to capture the most plausible outcomes from the prohibition on reshuffling, this language is deliberately not specific, and it remains to be seen what particular actions will constitute resource reshuffling under such rules. As such, we believe it is important to represent the incentives to reshuffle, and to consider the scenario in which resources are reshuffled, if for no other reason than to weigh the economic pressures that such restrictions will be pushing against.

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Notes

[1]Ironically, policy makers are often attracted to consumer-based regulations either because much of the production takes place outside of their jurisdiction or because they fear that regulating only producers within their jurisdiction will lead to leakage.

[2]WCI, 2008.

[3]In the 2008 CARB Inventory unspecified imports are assigned a default emission factor equivalent to US EPAs annual non-baseload output emissions rates for the Northwest (1201 lbs/MWh) or Southwest (1334 lbs/MWh) eGRID regions, depending on where the power entered California. These emission factors, which were reported in 2007 for the 2005 measurement year, may be accessed at: http://cfpub.epa.gov/egridweb/ghg.cfm.

[4]Although the California market was notorious for its high degree of market power in the early part of this decade, competitiveness has dramatically improved in the years since the California crisis, while the vast majority of supply in the rest of the WECC remains regulated under traditional cost-of-service principles.

[5]When the market is modeled as perfectly competitive, as it is here, the results are relatively insensitive to the elasticity assumption, as price is set at the marginal cost of system production and the range of prices is relatively modest.

[6]It is important to recognize that our modeling approach not only assumes that existing zero-carbon sources will not change *how much* they produce but also *when* they produce it. An interesting question is whether a redistribution of hydro-electric power across time could lower CO2 emissions by enabling a better management of fossil generation sources. Such an analysis would require a co-optimization of hydro and thermal electric production and is beyond the scope of this paper.

[7]This approach to modeling unit availability is similar to Wolfram (1999) and Bushnell, Mansur and Saravia (2008).

[8]The final "node" in the network consists of the Intermountain power plant in Utah. This plant is connected to southern California by a high-capacity DC line, and is often considered to be electrically part of California. However under some regulatory scenarios, it would not in fact be part of California for GHG purposes, it is represented as a separate location that connects directly to California.