Leakage Chapter Outline (DRAFT)

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Levels of climate ambition—and the stringency of climate policies—are escalating in jurisdictions such as Europe, Canada, and California. At the same time, a majority of global greenhouse gas (GHGs) emissions remain unregulated.[1] This poses a formidable challenge for jurisdictions working to fight global climate change with ambitious local or regional policies.

When only a subset of emissions sources is subject to costly regulations, industrial production and associated emissions may shift to less regulated jurisdictions – a process known as emissions "leakage". Leakage has been a defining concern in the design and implementation of California's GHG cap-and-trade program.

In principle, emissions leakage can be mitigated by imposing a commensurate compliance obligation on the GHG emissions embodied in imported products (and exempting emissions embodied in exports). Border carbon adjustments (BCAs) can help level the carbon playing field for domestic and foreign suppliers. An alternative approach uses production incentives to mitigate leakage risk. Under a cap-and-trade regime, these production subsidies can be conferred in the form of GHG permits allocated for free on the basis of industrial output (sometimes referred to as "output-based allocation").

Notably, California's GHG cap-and-trade policy integrates both of these approaches. Electricity importers into California must surrender allowances on the basis of the GHG emissions intensity of imported power. Outside the electricity sector, emissions intensive and trade exposed (EITE) producers receive free allowance allocations on the basis of industrial output.

As California's GHG regulations become more stringent, GHG permit prices – and the potential for emissions leakage – will increase. Now is an opportune time to assess whether California policies are achieving the desired objectives. This chapter reviews the empirical evidence and identifies some policy design challenges and opportunities.

California's Border Carbon Adjustment

GHG emissions associated with electricity consumption have been regulated under the cap-and-trade program since 2013. GHG emissions from in-state producers are regulated directly, while electricity importers have an obligation to purchase permits for GHG emissions associated with imports. With almost a decade of data to analyze, researchers have been investigating the impacts of the GHG cap-and-trade program design on western electricity market operations and associated GHG emissions.

[1] The World Bank estimates that existing GHG pricing programs cover 21.5% of anthropogenic emissions. https://carbonpricingdashboard.worldbank.org/map_data

To estimate the causal impacts of a policy intervention on emissions outcomes, we need to compare the GHG emissions we observe under the policy against a credible estimate of the emissions patterns we would have observed absent the policy (i.e. the counterfactual). In the context of California's GHG cap-and-trade program, estimating counterfactual GHG emissions is complicated by two factors.

- California climate policies impact the entire western electricity market: All electricity producers in the integrated western electricity market are directly *or indirectly* impacted by California's cap-and-trade program as the market shifts production away producers with compliance obligations and towards out-of-state producers with no compliance obligations. Thus, comparing emissions changes at in-state plants against emissions changes at plants in neighboring states can overstate policy impacts.

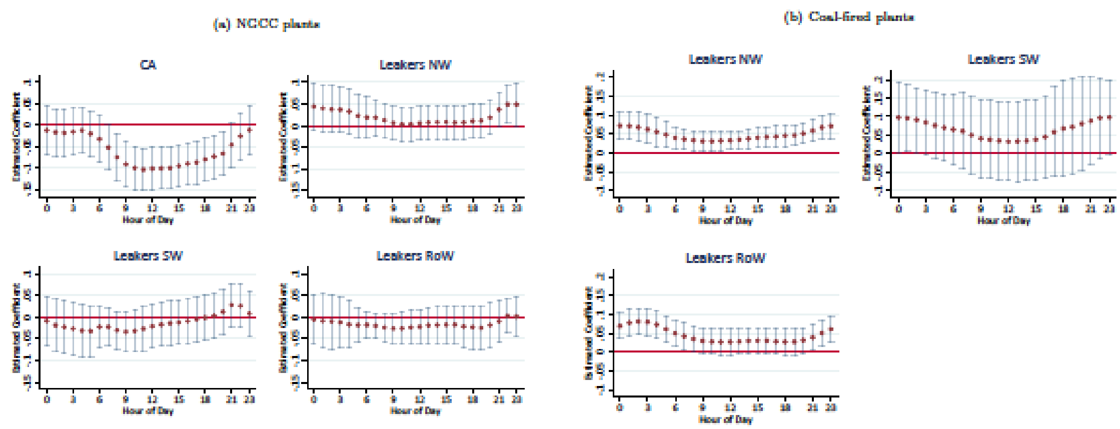
- Coincident changes confound impact analysis: The introduction of California's GHG trading program coincided with other big changes in the western power market (such as the closure of the San Onofre nuclear generating station - SONGS, and increased support for renewable energy). It can therefore be challenging to disentangle the effect of California's carbon pricing policies from these confounding factors.

Researchers are addressing these challenges in a variety of ways. Once recent paper by Lo Prete et al. (2021) matches electricity generating units in the WECC (western electricity coordinating council) with observationally similar electricity generating plants outside of WECC. This approach assumes that matched "control" plants outside of WECC are not impacted by California's climate policies and can be used to estimate what production patterns in the WECC market would have looked like absent the GHG cap-and-trade program. A second approach uses detailed models of the 2019 western wholesale electricity market to simulate market outcomes with and without the border adjustment

Starting with the first approach, Lo Prete et al. (2021) analyze the impacts of California's GHG cap-and-trade program on plant-level electricity production and market-level GHG emissions over the first four years of policy implementation. The difference-in-differences comparison of power plant operations between WECC/matched control plants before/after the introduction of California's cap-and-trade program provides the basis for estimating program impacts on WECC plant utilization rates.

The authors estimate relative *decreases* in electricity generation among California producers and relative *increases* in electricity generation among out-of-state generators supplying the western market in the years following the introduction of the GHG cap-and-trade program. These findings suggest that electricity production at directly regulated gas plants in California is being reallocated to out-of-state producers. However, a closer look at the data reveals underlying diurnal patterns that are not so consistent with this synchronous substitution story.

The figures below show the estimated reductions in electricity production at California (CA) gas plants relative to matched counterparts in other parts of the country across hours of the day. Notably, reduced utilization at California gas plants is concentrated during daylight hours. In contrast, the right figure shows how relative increases in capacity utilization at western coal plants (outside California) happens in the evening hours. If these relative changes in utilization rates at in-state versus out-of-state power plants were driven by permit-price-induced changes in relative operating costs, changes in utilization rates should be *coincident* given very limited energy storage capacity.



Notes: This figure is taken from Lo Prete et al (2021). The left panel summarizes relative changes in utilization rates at natural gas plants (relative to matched controls). The right panel summarizes relative changes at coal plants (relative to matched controls). "Leakers" refers to power plants that are located outside of California but inside WECC.

What explains the relative reduction in the capacity factors of California's gas plants during daylight hours and the relative increase in the utilization of coal plants in neighboring western states in evening hours? The retirement of the large San Onofre nuclear power plant (SONGS) in 2012 and accelerated investment in solar PV are two factors that likely contribute to these changes. In addition, there's another kind of emissions leakage that could be contributing to the increased coal generation. If out-of-state coal generation is being imported into California as "unspecified" power –without an identified generation source and associated emissions rate - then increased coal utilization could reflect a market response to the assignment of GHG compliance obligations for in-state versus out-of-state producers.

Two recent papers investigate alternative channels through which California's GHG trading program might alter the carbon footprint of imported electricity. Under the current California market design, the GHG compliance obligation for "unspecified" imports is determined on the basis of a default GHG emissions rate. If imports can document a carbon intensity that is lower than the default, they can reduce their compliance obligation. This GHG accounting system creates an incentive to preferentially allocate low carbon resources in neighboring states to

California. This resource “shuffling” understates the carbon footprint of California’s electricity imports.

Fowlie, Peterson, and Reguant (2021) and Xu and Hobbs (2021) both use detailed models of the western wholesale electricity market to simulate market outcomes with and without this border adjustment. Both studies document significant potential for resource shuffling. Both studies also investigate an alternative `uniform’ border carbon adjustment that limits importers’ ability to claim GHG emissions below a prescribed level. Notably, under this alternative, the potential for resource shuffling is limited and emissions leakage is more effectively mitigated.

Summary: Researchers have documented significant potential for GHG emissions leakage and resource shuffling in the western wholesale electricity market. Attempts to empirically estimate the extent to which GHG emissions leakage is happening are confounded by the effects of coincident policy changes and market developments. That said, observed patterns of GHG emissions across the western market are generally consistent with some resource shuffling. Research has further shown that limiting suppliers’ ability to claim carbon intensities below the BCA default rate could more effectively mitigate leakage potential.

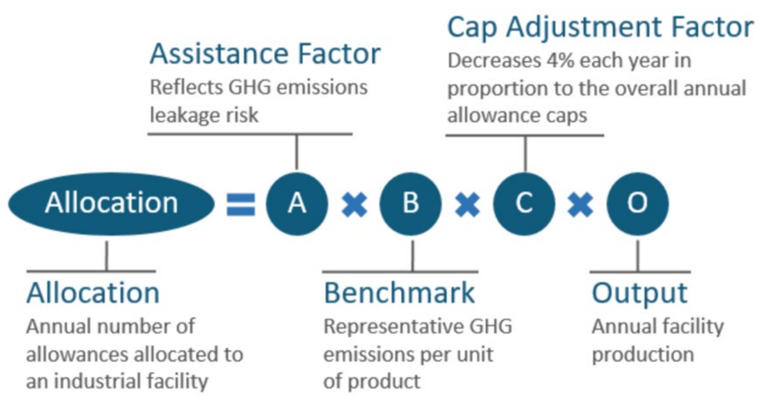
A BCA design that assigns the same emissions intensity to all out of state imports may not be permissible under the dormant commerce clause. However, in the context of CAISO’s energy imbalance market (EIM), California has devised an innovative way to adjust for GHG leakage assessed in the EIM. When the assessed GHG impacts of California imports exceeds the accounting compliance obligation, CARB retires GHG permits to offset the excess leakage.

Efforts are now underway to launch an extended day-ahead market (EDAM) to include Western entities. This has the potential to further optimize supply and transmission resources and advance clean energy goals across the West. However, it could also lead to increased amount of emissions leakage in California. This presents a challenge – and an opportunity—to further innovate around GHG accounting to accommodate this larger market.

Recommendation – AB32 requires that CARB account for the GHG emissions associated with electricity imports into California. CARB should engage to provide expert advice to CAISO staff on GHG accounting approaches that are being considered as part of the EDAM market design. CARB should explore the possibility of making ex post cap adjustments to offset leakage assessed in the EDAM. This is a promising approach insofar as it presents no significant legal risks. That said, extending this approach to the EDAM will present potential technical implementation challenges that will merit careful design consideration.

Output-based GHG allowance allocations (industrial sectors)

Output-based rebating of permits offers an alternative approach to mitigating emissions leakage. The California Air Resources Board (CARB) uses this approach for industrial producers. The original formula used to calibrate these allowance allocations is summarized below:



Annual facility allowance allocations depend on facility-specific output scaled by an assistance factor, a sector-specific benchmark, and cap adjustment factor:

- Assistance factors were originally intended to reflect sector-specific leakage risk.
- Benchmarks are sector-specific and set by CARB.
- Adjustment factor declines each year in proportion to the overall annual allowance caps (and decreases 4 percent per year during the period 2020-2030).
- The allocation is based on updated information about annual facility production (i.e. output) so as to avoid windfall and undeserved free allocation of allowances and to maintain the incentive to boost production.

Notably, under AB 398, assistance factors were set to 100 percent for all sectors. Thus, production subsidies are now targeted purely on the basis of emissions intensity.

Output-based allocation updating can confer important leakage mitigation benefits. But it also comes at a cost. First, an opportunity cost is incurred when allowances are allocated for free to industrial producers. In 2020, over 58 MMT of allowances were allocated for free to industrial producers on the basis of output. At an allowance price of around $17/ton, this allocation constitutes roughly $1 billion in potential revenue diverted from the greenhouse gas reduction fund that is used to support program-related investments. Second, output-based rebating increases the abatement costs incurred to meet the emissions cap when it dilutes the incentive to reduce production at entities receiving the production subsidy. Given these costs, it is important to judiciously target subsidies at industries truly at leakage risk.

Output-based subsidies should ideally be targeted towards firms or industries that face the greatest leakage risk. This risk will be greatest in those industries where emissions intensive foreign production is highly responsive to policy-induced changes in domestic operating costs. Given the practical challenges with assessing leakage risk at a granular level, policy makers have been inclined towards simpler approaches such as the one used in California.

Research by Fowlie and Reguant (2021) empirically investigates the extent to which international trade flows, and associated foreign emissions, respond to changes in U.S. energy costs. They estimate industry-specific measures of emissions leakage risk to capture the increase in foreign emissions associated with incremental reductions in domestic production. Notably, they find relatively low leakage risk for several emissions intensive industries that are not highly trade exposed. These authors go on to show how allocating permits to emissions intensive industries that are not highly trade exposed incurs the costs of leakage mitigation while delivering a fraction/none of the leakage mitigation benefits.

Recommendation: Now is an opportune time for CARB and the legislature to re-visit the approach it currently takes to calibrate the output-based allocations to industrial sources and sectors. In California, leakage-mitigating subsidies are allocated on the basis of emissions intensity, regardless of the level of trade exposure. Over-allocation of allowances to industries that face low levels of leakage risk incurs substantial costs in excess of leakage mitigation benefits.

There are mounting concerns that California's GHG allowance budget is not sufficiently stringent to drive the immediate emission reductions needed in this decade. Reducing the assistance factor (or benchmark) for industries where output-based subsidies are deemed excessive would provide a way to increase program stringency while also delivering efficiency gains.

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