

April 4, 2014

Climate Change Program
California Air Resources Board
1001 I Street
Sacramento, CA 95814

**Re: Comments on Proposed Cap-and-Trade Regulations, 15-Day Changes
Resource Shuffling Safe Harbors — § 95852(b)**

Thank you for the opportunity to comment on the proposed carbon market regulations. Please incorporate by reference my previous comment letter from October 23, 2013,¹ and its attachments.²

Once again, I write to express serious concerns that the resource shuffling safe harbors will cause significant quantities of greenhouse gas emissions to leak out of California's carbon market. Since my last comment letter, significant leakage has already occurred via three major transactions that appear to be permissible under the safe harbor policy. As a result, between 30 and 60 million tons of CO₂ have already leaked or are imminently leaking out of California's market.

These new results demonstrate that the proposed regulations are inconsistent with clear statutory directives from California's climate law, AB 32. In addition, they underscore ARB's failure to analyze the environmental impacts of the proposed regulatory changes as required under the California Environmental Quality Act.

1. ARB's proposed resource shuffling safe harbors contradict the purpose and requirements of AB 32.

A. The safe harbors have already caused and will continue to cause resource shuffling, resulting in significant leakage of greenhouse gas emissions to neighboring states.

The proposed regulations are fundamentally inconsistent with California's climate policy objectives because the resource shuffling safe harbors have caused and will continue to cause significant leakage of greenhouse gases to other states. In plain English, this

¹ Danny Cullenward, Proposed Amendments to the California Cap-and-Trade Program (September 4, 2013 Proposed Regulation Order). Comment letter to the California Air Resources Board (Oct. 23, 2013), available at <http://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=capandtrade13>.

² Danny Cullenward, Don't let accounting tricks dominate the carbon market. San Jose Mercury News op-ed (Oct. 21, 2013), available at http://mercurynews.com/opinion/ci_24354840/danny-cullenward-dont-let-accounting-tricks-dominate-carbon; Danny Cullenward and David Weiskopf, Resource Shuffling and the California Carbon Market. Stanford Law School ENRLP Working Paper (July 13, 2013), available at <http://law.stanford.edu/publications/resource-shuffling-and-the-california-carbon-market>.

means that the cap-and-trade market will not actually reduce greenhouse gas emissions as planned. To the extent that regulated parties in California rely on resource shuffling to comply with climate policy, the carbon market will produce the false appearance of emissions reductions. Put another way, resource shuffling means that the cap is no longer firm.

California's climate law, AB 32, defines leakage as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state."³ Under this definition, any reduction in emissions within California that is caused by the transfer of emissions liability outside the state constitutes leakage.

The risk of leakage is arguably greatest in the electricity sector, where the problem is known as resource shuffling. For example, consider a California utility that imports specified power from a coal power plant in Arizona. If the California utility sells its interest in that power plant to a party that is not a covered entity in California's carbon market, the liability for those emissions will be transferred out of the State's carbon market system. Suppose the California utility then acquires replacement power from a natural gas power plant; meanwhile, the coal plant continues to produce power for its new owner.

As a result of these transactions, the California utility would report a reduction in greenhouse gas emissions. At the same time, that reduction would be offset by an increase in emissions of greenhouse gases outside the state. Critically, there would be no change in net emissions to the atmosphere. The liability for the high-emitting resource would have merely been transferred out of California's carbon market, allowing both the State and the covered entity to claim credit for emissions reductions that have not actually occurred.

Table 1: Resource Shuffling Example
(Using stylized greenhouse gas emissions units)

	California	Western State X	Total
Step 1	100	50	150
Step 2	50	100	150
Change	- 50	+ 50	0

Table 1 illustrates this example numerically. In the first step, the California utility owns a power plant and an out-of-state utility owns a natural gas power plant. For simplicity, assume the coal plant emits 100 units of greenhouse gases, whereas the natural gas plant emits 50 units of greenhouse gases; both produce the same amount of electricity and

³ Cal. Health & Safety Code § 38505(j).

are located outside of California. Because first deliverers of electricity are liable for the emissions associated with their imports,⁴ the California utility will initially report the coal power plant's emissions.

In the second step, the parties swap ownership interests in the two plants. As a result, the California utility reports a reduction in emissions that is offset by an increase in emissions outside the state, with no net change in emissions to the atmosphere. In this case, 50 units of greenhouse gas emissions have leaked out of California's system. Note that if this example involved a zero-carbon replacement resource (like nuclear or renewable energy) instead of natural gas, the leakage would be 100 units of greenhouse gas emissions.

1. The Safe Harbors Will Cause Significant Leakage.

Economists have repeatedly warned ARB that the proposed safe harbors effectively negate the prohibition on resource shuffling and will result in significant leakage. Previously, my colleague David Weiskopf and I estimated leakage impacts from resource shuffling of legacy coal power contracts, finding the potential for between 108 and 187 million tons of CO₂ through 2020.⁵ That view is consistent with what ARB's independent Emissions Market Assessment Committee ("EMAC") economists have estimated. For example, a June 2013 EMAC report found that the likely range of leakage impacts from resource shuffling would be between 120 and 360 million tons of CO₂ through 2020, including both legacy coal contract shuffling and other forms of resource shuffling.⁶ Another paper from University of California economists found that "even a modest weakening of the [rules and practices] targeted at limiting reshuffling will greatly undermine the strictness of the emissions cap through reshuffling."⁷

Under the proposed regulations, any transaction fitting a safe harbor is exempted from the prohibition on resource shuffling.⁸ In case there is any doubt about the breadth of the safe harbors and their impacts, I review two here, using the numbering in the proposed regulations:

⁴ Cal. Code Regs. tit 17, § 95852(b).

⁵ Cullenward and Weiskopf, *supra* note 2 at 27.

⁶ Severin Borenstein, James Bushnell, Frank A. Wolak, and Matthew Zarazoga-Watkins, Forecasting Supply and Demand Balance in California's Greenhouse Gas Cap and Trade Market. Draft EMAC report 1, 14 (June 12, 2013).

⁷ James Bushnell, Yihsu Chen, and Matthew Zaragoza-Watkins, Downstream Regulation of CO₂ Emissions in California's Electricity Sector. Energy Institute @ Haas Working Paper #236, at 4, *available at* http://ei.haas.berkeley.edu/pdf/working_papers/WP236.pdf. The specific measures referred to in this quote refer to the treatment of legacy coal power import contracts and the extent to which zero-greenhouse gas resources like hydroelectricity can be resource shuffled. *Id.* at 10.

⁸ Proposed regulations amending Cal. Code Regs. tit. 17, § 95852(b)(2)(A).

6. Electricity deliveries that substitute for deliveries that have been discontinued because of termination of a contract or divestiture of resources for reasons other than reducing a GHG compliance obligation.⁹
7. Electricity deliveries that are necessitated by early termination of a contract for, or full or partial divestment of, resources subject to the EPS rules.¹⁰

The sixth safe harbor exempts from the definition of resource shuffling any transaction motivated by any purpose except avoiding the compliance costs of California's carbon market. This provides countless options for avoiding the resource shuffling prohibition. For example, covered entities could plausibly justify nearly any resource shuffling transaction by citing complimentary objectives, like reducing local air pollution impacts from their power imports, minimizing costs, or even something so mundane as diversifying contractual counterparties. As a result, ARB would have serious trouble bringing any enforcement actions because defendant parties would always be able to claim a plausible complimentary motivation. At best, enforcement actions would face a difficult evidentiary question; at worst, a reviewing court could conclude that the safe harbor protects all transactions where any alternative rationale is present.

If the sixth safe harbor is unnecessarily vague, the seventh safe harbor offers an explicit loophole. It unambiguously exempts any transaction that involves divestment of resources subject to the EPS rules, referring to the emissions performance standard set by SB 1368. Presumably ARB's intent is to allow California entities to exit their interests in legacy coal contracts, which, as described above could result in more than 100 million tons of CO₂ leaking out of the market. As written, however, the safe harbor goes even further and provides an almost unlimited protection to all major utility power contracts.

By defining the seventh safe harbor by reference to any divestment of resources subject to the EPS rules, ARB would exempt any transaction involving both utilities and long-term baseload power contracts. Technically, the EPS applies to "load-serving entities" and "local publicly owned electric utilities."¹¹ The EPS prohibits "long-term financial commitments," which are defined as either "new ownership investment[s] in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation."¹² Thus, the seventh safe harbor would even exempt any transaction involving a utility and a long-term baseload power contract or ownership interest; even divestment of natural gas facilities would be permissible.

As these examples demonstrate, the safe harbors effectively undo the prohibition on resource shuffling. Therefore, if the proposed regulations are adopted, covered entities in

⁹ *Id.* § 95852(b)(2)(A)(6).

¹⁰ *Id.* § (b)(2)(A)(7).

¹¹ Cal. Public Utilities Code §§ 8340(h)-(i).

¹² *Id.* § 8341(a) (the prohibition); *id.* § 8340(f) (the definition).

the electricity sector would be officially free to engage in transactions that would leak tens to hundreds of millions of tons of greenhouse gas emissions to neighboring states.

2. The Safe Harbors Have Already Caused Significant Leakage.

ARB will formally undermine its prohibition on resource shuffling if it adopts the proposed regulations. In practical terms, however, ARB already undermined the carbon market's integrity with its November 2012 informal guidance on resource shuffling.¹³ The current administrative process would simply codify the changed regime ARB introduced then, as that document lists the very same safe harbors proposed here.

It should come as no surprise, then, that several major resource shuffling transactions have already occurred. Because these transactions all involve or relate to baseload electricity contracts—specifically, divestment from legacy coal power contracts—they appear to be entirely permissible under the broad safe harbors as articulated in ARB's regulatory guidance document. The three transactions are described below, offering further indication of the environmental and economic impacts of ARB's proposed regulatory reforms.

- **Southern California Edison / Four Corners Units 4 & 5.**

At the end of December 2013, Southern California Edison completed the sale of its interests in the coal-fired Four Corners power plant in Arizona to APS, a utility based in Arizona.¹⁴ As a result of the transaction, SCE will report a reduction in emissions in the California carbon market because whatever replacement power SCE secures will have lower emissions than conventional coal power. In turn, the Arizona utility's emissions profile will increase. Thus, this transaction caused emissions to leak out of California's carbon market.

- **California Department of Water Resources / Reid Gardner Unit 4.**

Pursuant to its Climate Action Plan,¹⁵ the California Department of Water Resources terminated a contract with Reid Gardner Unit 4, a coal-fired facility in Nevada. DWR's original contract term ended in July 2013, at which point the Department elected not to renew the contract with the plant's owner, Nevada Power

¹³ California Air Resources Board, Cap-and-Trade Regulation Instructional Guidance, Appendix A: What is Resource Shuffling? (November 2012), *available at* http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf.

¹⁴ APS Press Release, APS completes purchase at Four Corners power plant (Dec. 31, 2013), *available at* <https://www.aps.com/en/ourcompany/news/latestnews/Pages/aps-completes-purchase-at-four-corners-power-plant.aspx>.

¹⁵ California Department of Water Resources, Climate Action Plan, Phase I: Greenhouse Gas Emissions Reduction Plan (May 2012). Note that terminating the Reid Gardner contract accounts for approximately 80% of the Department's planned emissions reductions. *Id.* at 10, Table S-1 (estimating that by 2020, DWR will have reduced 882,700 mtCO₂ per year by terminating the Reid Gardner, compared to 1,116,730 mtCO₂ per year from all measures combined).

Company. DWR will report a reduction in emissions in California, likely from using replacement power from the new natural gas-fired Lodi Energy Center in California.¹⁶ Nevada Power Company will continue to operate Reid Gardner Unit 4, resulting in an increase in emissions outside of California.¹⁷ Thus, this transaction caused emissions to leak out of California's carbon market.

- **Los Angeles Department of Water and Power / Navajo Generating Station.**

Earlier this year, the Los Angeles Department of Water and Power approved the purchase of a natural gas-fired power plant in Nevada called the Apex Power Plant. According to regulatory filings, this facility was purchased as part of LADWP's plan to divest its interest in the Arizona-based, coal-fired Navajo Generating Station in 2015, prior to the end of its contract term in 2019.

Because LADWP has not yet divested—and therefore cannot report emissions reductions within California—this transaction does not yet constitute resource shuffling. Nevertheless, it contains a candid and telling admission from LADWP. In a regulatory filing with the Los Angeles City Council, LADWP states that divesting from the Navajo Generating Station will reduce its CO₂ emissions liability, **“relieving LADWP from having to purchase emission credits to comply with the statewide cap and trade program.”**¹⁸

Indeed, this appears to be a textbook example of “a plan, scheme, or artifice to receive credit for emissions reductions that have not occurred”—the very definition of resource shuffling currently on the books.¹⁹ Yet it clearly fits within several of the safe harbors in the guidance document and for this reason would not violate the proposed regulatory amendments.²⁰

¹⁶ *Id.* at 58 (indicating that DWR has a 33.3% interest in the Lodi Energy Center and plans to use those imports to replace the lost deliveries from Reid Gardner). According to DWR, this facility is 16% more efficient than ARB's default unspecified emissions factor (361 vs. 428 mtCO₂e/GWh). *Id.*

¹⁷ Nevada recently passed SB 123, a law that requires Nevada Power Company to retire 300 MW of coal-fired capacity by the end of 2014, and an additional 250 MW by the end of 2017. This has generally been interpreted to mean closing Reid Gardner Units 1, 2, and 3 (each 100 MW) in 2014, and Reid Gardner Unit 4 (250 MW) in 2017. Leakage will continue until Reid Gardner Unit 4 retires.

¹⁸ Los Angeles Department of Water and Power, LADWP Board Approval Letter re: LADWP Apex Power Project Power Sales Agreement (PSA) No. BP 13-055 (Nov. 26, 2013), at 3, *available at* <http://cityclerk.lacity.org/lacityclerkconnect/index.cfm?fa=ccfi.viewrecord&cfnumber=13-1635>.

¹⁹ Cal. Code Regs., tit. 17, § 95802(a)(252).

²⁰ For example, LADWP cites several other motivating factors behind its decision to divest—such as the expectation of better prices from selling the coal contract early, and the intention to subsequently increase renewable energy and energy efficiency resources—and would therefore likely meet the sixth safe harbor conditions. LADWP, *supra* note 18 at 3. In any case, the transaction involves replacement power LADWP could argue “is necessitated by” divestment of a resource subject to the EPS rules, clearly satisfying the seventh safe harbor.

Once divestment from the Navajo Generating Station occurs as planned, LADWP will report a reduction in emissions within the California market. In turn, emissions outside the state will increase. Thus, LADWP's stated intention to shift the liability for its legacy coal resources to unregulated parties and report an emissions reduction due to its purchase of relatively clean replacement power indicates a firm intention to cause leakage.

These three transactions demonstrate that greenhouse gas emissions are already leaking out of California's carbon market at scale. As a result, between 30 and 60 million tons of CO₂ have leaked or are imminently leaking out of California's carbon market. Full calculations are presented in Tables 2 through 5, contained in the Appendix to this letter.

B. The safe harbors violate AB 32's clear requirement that ARB regulations minimize leakage. (Cal. Health & Safety Code § 38562(b)(8))

California's climate law speaks directly to this carbon market design issue. AB 32 requires that "to the extent feasible," ARB "shall ... minimize leakage."²¹ Here, the proposed regulations effectively undo the formal prohibition on resource shuffling. Because resource shuffling has caused and will continue to cause significant leakage of greenhouse gas emissions to other states, the proposed regulations do not minimize leakage.

A regulation that does not minimize leakage would be permissible under AB 32 only if there are no feasible alternatives. In this case, however, ARB has a wealth of alternative options. First, ARB could strike the proposed safe harbors and leave in place the original prohibition on resource shuffling in its regulations. Second, ARB could write new regulations that increase compliance flexibility while preventing leakage in cross-border electricity transactions. For example, ARB could require covered entities to retain emissions liability when shifting major electricity contracts to unregulated, out-of-state parties.²² Third, ARB could lower the overall cap under AB 32 to reflect observed and anticipated leakage, such that the net reduction after leakage meets the 2020 emissions target.

As these options demonstrate, ARB has a number of feasible alternatives—including doing nothing at all to the existing regulations. ARB's decision to nevertheless encourage leakage through the codification of safe harbors can only be described as arbitrary and capricious.

Because (1) the safe harbors have caused and will continue to cause significant leakage, and (2) ARB has a range of feasible alternatives, the proposed regulations do not minimize leakage as required by state law.

²¹ Cal. Health & Safety Code §§ 38562(b), (b)(8).

²² For a fully developed regulatory text implementing this approach, *see* Cullenward and Weiskopf, *supra* note 2, Appendices I & II.

C. The safe harbors violate AB 32's clear requirement that ARB regulations produce emissions reductions that are real, permanent, quantifiable, verifiable, and enforceable. (Cal. Health & Safety Code § 38562(d)(1))

By definition, leakage creates emissions reductions that are not real because when leakage occurs, the associated emissions reductions reported in California do not cause net emissions reductions to the atmosphere. Instead, they merely indicate the transfer of emissions liability to unregulated, out-of-state parties. Accordingly, the reported emissions reductions due to emissions reductions are not real, permanent, accurately quantified, or verifiable. Even if ARB technically preserves its prohibition on resource shuffling, the safe harbors render it unenforceable. Thus, the safe harbors also violate AB 32's requirement that emissions reductions be "real, permanent, quantifiable, verifiable, and enforceable."²³

2. ARB's environmental analysis is legally insufficient because it fails to acknowledge the significant environmental harms caused by the safe harbors.

Although the proposed amendments are problematic enough on their own, ARB's failure to acknowledge the expected—and quite likely intended—consequences of its actions is all the more troubling. ARB's September 2013 Staff Report on the current proposed regulations contains an environmental analysis for the proposed regulations.²⁴ This analysis brazenly relies on misleading comparisons to avoid assessing the environmental impacts of the proposed regulatory changes. It must be updated to serve the most basic purposes of the California Environmental Quality Act ("CEQA"), which are to:

- (1) Inform governmental decision makers and the public about the potential, significant environmental effects of proposed activities.
- (2) Identify ways that environmental damage can be avoided or significantly reduced.
- (3) Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.
- (4) Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.²⁵

²³ Cal. Health & Safety Code § 38562(d)(1).

²⁴ California Air Resources Board, Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Staff Report: Initial Statement of Reasons 1, 44 (Sept. 4, 2013).

²⁵ Cal. Code Regs tit. 14, §§ 15002(a)(1)-(4).

Even as it implements major reforms that undermine the economic and environmental integrity of the carbon market, ARB nevertheless manages to stay silent on the expected environmental impacts. ARB's 2013 Staff Report falsely construes the proposed safe harbors as mere "clarifying language" that "would not affect the compliance responses available to [covered] entities from what was analyzed in the 2010 FED."²⁶ That reliance is misplaced because the 2010 FED analyzed a rulemaking that produced the original prohibition on resource shuffling, which did not include any safe harbors. In other words, ARB falsely claims that the current proposed safe harbors do not affect its prohibition on resource shuffling.

This is simply incorrect. The current regulation says only that "[r]esource shuffling is prohibited and is a violation of [Article 5 of the Cap-and-Trade Regulations]";²⁷ it says nothing about thirteen broad exemptions to this supposedly-preserved rule. As a result of the proposed safe harbor provisions, ARB's prohibition on resource shuffling will become an unenforceable formality. Between 30 and 60 million tons of CO₂ have leaked or are imminently leaking as a result, exceeding any reasonable threshold for significance under CEQA.²⁸ Because the proposed safe harbors would radically modify the carbon market regulations as they currently exist, CEQA requires ARB to conduct an analysis of the environmental impacts.²⁹

By claiming that it is not, in fact, changing its market rules, ARB suggests that adding multiple loopholes that undermine a critical market rule will have no environmental effect on the performance of its cap-and-trade market. Yet as my previous comment letter, ARB's own economic advisers (EMAC), and the observed resource shuffling transactions described in this letter show, the proposed regulatory changes have caused and will continue to cause significant leakage. In turn, this will lead to significant environmental consequences, as ARB put it when addressing leakage in its 2010 FED:

²⁶ California Air Resources Board, *supra* note 24 at 51 (citing California Air Resources Board, 2010 Cap and Trade Regulation, Appendix O: Functional Equivalent Document 1, 1 (Oct. 28, 2010)). ARB concludes its 2013 Staff Report analysis by stating that:

"Resource shuffling was disclosed as a prohibited activity in the 2010 Regulation as analyzed in the 2010 FED. Therefore, the potential for adverse impacts associated with the proposed clarifications to this definition fall within the scope and scale of those previously analyzed."

Id. at 59.

²⁷ Cal. Code Regs. tit. 17, § 95852(b)(2).

²⁸ *See* Cal. Code Regs. tit. 14, § 15064.4 (providing guidelines for determining the significance of impacts from greenhouse gases for the purposes of CEQA analysis).

²⁹ ARB could argue that the current regulatory proposal will have no significant changes to the status quo, but only if it acknowledges that the safe harbor regime is already in effect due to the November 2012 regulatory guidance document. Yet that admission would raise serious questions as to whether introduction of the regulatory guidance document constituted impermissible underground regulation that avoided the basic requirements of California administrative law, such as offering the public with formal notice and an opportunity to comment.

“If leakage occurs, the reductions in GHGs achieved by sources in California may be undone by a corresponding increase in emissions outside of California [Leakage] would likely lead to increased adverse environmental impacts outside of California, and would have negative effects on California’s economy.”³⁰

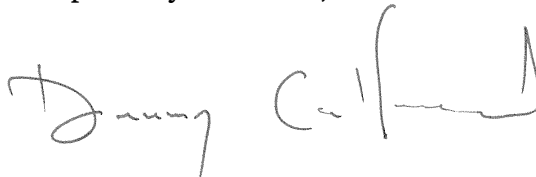
Because the resource shuffling safe harbors have caused and will continue to cause significant environmental consequences—impacts ARB has never acknowledged or analyzed—ARB has not satisfied the basic requirements of CEQA. To comply, ARB must assess the environmental consequences of its proposed safe harbor regulations and evaluate the feasibility of alternative approaches.

3. ARB can still pursue solutions, but must first acknowledge the problem.

Although the safe harbors have already created significant leakage, ARB can still act to fix the problem. There are at least two solutions. First, ARB could estimate the observed and anticipated leakage resulting from unfettered resource shuffling, and lower the overall cap such that the net emissions reductions meet the 2020 target. Alternatively, ARB could revoke the informal guidance on resource shuffling, implement new regulations that either restrict resource shuffling or price any leakage from cross-border electricity transactions, and adjust the cap to reflect the existing leakage observed to date.

Both solutions require ARB to acknowledge the impacts that have already happened and will continue to occur if left unchecked. Until that time, the credibility of the state’s carbon market will remain in question.

Respectfully submitted,



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I am writing only in my individual capacity.*

³⁰ California Air Resources Board, 2010 Cap and Trade Regulation FED, supra note 26 at 378 (discussing leakage in the context of a CEQA evaluation of an alternative policy design that would employ border adjustments to goods and services imported to California).

Appendix — Calculating Observed Leakage

Calculating leakage from resource shuffling transactions requires information about the expected future production of both divested and replacement resources. If the precise pairwise replacement resource cannot be identified at the time of divestment, the leakage impacts can be bounded by the use of natural gas and zero-carbon replacement power benchmarks. Leakage will be highest if the replacement power is zero-carbon, and lower if natural gas is used; whatever mixture of replacement power supplies is used will fall in between these two benchmarks.

The first step in calculating leakage is to determine the period during which leakage will occur. This period begins when a covered entity divests from a high-emitting resource and ends at the earlier of (1) the end of the last carbon market compliance period in December 2020, or (2) when the high-emitting, divested resource retires. Leakage periods for the three transactions are shown in Table 2.

Next, the annual leakage rate can be estimated using historical and forecasted electricity production delivered to California purchasers, along with facility-level emissions rates. Here, a representative production level is calculated from recent and projected production as reported by utility and power purchasers to the California Energy Commission.³¹ The facility-level emissions rates are based on heat rates from the Velocity Suite Database (provided by the California Energy Commission) and fuel emission rates from the Energy Information Administration.³² Table 3 contains the representative electricity production and emissions rate data for each facility based on this information.

Representative annual emissions for the three facilities are shown in Table 4. These numbers reflect the representative electricity production scenario for each facility, with emissions rates calculated for three fuel scenarios. The coal scenario uses the facility-level emissions rate from Table 3. The natural gas scenario uses ARB's default emissions factor

³¹ California Energy Commission, Form S-2 for 2011 and 2013, *available at* http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2011/ and http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2013/.

Note: Data from 2009 and 2010 come from 2011 Form S-2 filings. Data from 2011 and 2012 come from 2013 Form S-2 filings. Data from 2014-2015 are utility-reported forecasts in 2013 Form S-2 filings.

Note: SCE did not report 2013 numbers for Four Corners in the Form S-2 filings; the reported forecasts for 2014 and 2015 were zero due to planned divestment.

Note: DWR divested from Reid Gardner in July 2013. 2013 data were excluded to avoid intra-annual variations in energy consumption due to the department's use of the power for the state water project.

³² Ventyx, Velocity Suite Database, *available at* <http://www.ventyx.com/en/enterprise/business-operations/business-products/velocity-suite>; United State Energy Information Administration, Voluntary Reporting of Greenhouse Gases Program, Fuel Carbon Dioxide Emissions Coefficients, *available at* <http://www.eia.doe.gov/oiaf/1605/coefficients.html>.

for unspecified power (0.428 tCO₂ per MWh),³³ which is representative of baseload natural gas power plants. The zero carbon scenario assumes zero emissions, which is representative of nuclear or renewable power plants.

Finally, Table 5 reports the plant-level leakage estimates. Leakage estimates are determined by multiplying the number of years of leakage by the annual leakage rate. In the case of natural gas replacement power, the annual leakage rate is the difference between the coal and natural gas scenarios in Table 4. In the case of zero-carbon replacement power, the annual leakage rate is the difference between the coal and zero-carbon scenarios in Table 4 (*i.e.*, the same as the coal scenario). If production at the divested high-emitting facility increases after divestment, actual leakage will be higher than is reported here. If production falls, actual leakage will be lower. Similarly, if the facility retires earlier than specified in Table 2, actual leakage will be lower.

Table 2: Leakage Periods for the Three Observed Transactions

Facility	Divestment	Retirement?	Leakage Period
Navajo Generating Station	December 2015	Not planned.	5 years
Four Corners Units 4 & 5	December 2013	Not planned.	7 years
Reid Gardner Unit 4	July 2013	December 2017	4.5 years

Table 3: Representative Facility-Level Data

Facility	Period	Average Output (GWh per year)	Emissions Rate (tCO ₂ per MWh)
Navajo Generating Station	2009 – 2015	3,906	1.02
Four Corners Units 4 & 5	2009 – 2012	5,143	0.97
Reid Gardner Unit 4	2009 – 2012	872	1.08

³³ Cal. Code Regs. tit. 17, § 95111(b).

Table 4: Representative Annual Emissions

Facility	Annual Emissions (million tons CO ₂ per year)		
	Coal	Natural Gas	Zero-Carbon
Navajo Generating Station	3.97	1.67	0
Four Corners Units 4 & 5	4.97	2.20	0
Reid Gardner Unit 4	0.94	0.37	0

Table 5: Leakage from Observed Transactions

Facility	Leakage (Million tons CO ₂ through 2020)	
	Natural Gas Replacement	Zero Carbon Replacement
Navajo Generating Station	11.5	19.9
Four Corners Units 4 & 5	19.4	34.8
Reid Gardner Unit 4	2.6	4.2
Total	33.5	58.9

Attachments

- Borenstein et al., EMAC Market Report (June 2013)
- Bushnell et al., Energy Institute @ Haas Working Paper #236 (January 2013)

**Forecasting Supply and Demand Balance in California's
Greenhouse Gas Cap and Trade Market**

**by
Severin Borenstein, James Bushnell,
Frank A. Wolak and Matthew Zaragoza-Watkins¹**

June 12, 2013

I. INTRODUCTION

Among the many challenges in combatting climate change is the enormous uncertainty inherent in dealing with a problem of global scale with causes and impacts that are felt over the span of centuries. Independent of the impressive strides made in understanding the implications of atmospheric greenhouse gas (GHG) levels on the world's climate, great challenges remain in analyzing the economic costs of those changes, the costs of reducing emissions below dangerous levels, and even, fundamentally, the expected level of future emissions under a range of potential policies.

The cost of implementing GHG mitigation policies is a question of great interest and relevance at both the international and regional level. Of course, the specifics of the policy and the environment in which it is applied critically drive this question. Economists often frame the policy question in terms of the merits of a tax relative to those of an emissions cap, or one of "prices vs. quantities." In general, the benefits of a tax is that it can provide more predictable costs, while a cap can in theory provide more certainty as to the level of emissions.

In practice the reality of the implications of policy choice is more complex. Caps on emissions, where they have been applied, have been imposed only regionally, and only on a subset of the industries and sources producing GHG. Given that all these regions and industries interact with each-other in a global economy, the emissions certainty provided by capping only some industries in some countries is therefore greatly diluted. The certainty provided by a tax is limited by the extent to which policy makers can commit not to change the tax if it fails to produce the expected abatement. Last, the choice is frequently not one that requires full commitment to either a cap or tax alone. In many contexts, the two policies can be combined to reduce the risks presented by a commitment to either a cap or tax alone.

¹ This research was performed under a contract with the California Air Resources Board. Bailey, Borenstein, Bushnell, and Wolak are members of the Emissions Market Assessment Committee and the Market Simulation Group that advise CARB. Zaragoza-Watkins works with the EMAC and the MSG as a researcher. The opinions in this paper do not represent those of the California Air Resources Board or any of its employees. Emails addresses: Bailey: ebailey@haas.berkeley.edu; Borenstein: borenste@haas.berkeley.edu; Bushnell: jbbushnell@ucdavis.edu; Wolak: wolak@zia.stanford.edu; Zaragoza-Watkins: mdzwatkins@berkeley.edu.

California's Cap and Trade market in greenhouse gases was recently launched, with the first allowance auction taking place on November 14, 2012 and compliance obligations commencing on January 1, 2013. The market is scheduled to last for eight years, through the end of 2020. This market is a modified cap and trade system with a limited price-collar mechanism. There is both an escalating auction reserve price, managed through adjustments to the supply of allowances to the periodic auctions, and a *price-containment reserve* designed to have a restraining effect on prices on the high end.

While the general details of the operations of both the auction reserve price and containment reserve are outlined in the regulations developed by the California Air Resources Board (ARB),² there remains some uncertainty over the exact manner in which the containment reserve mechanism would be applied and the degree to which it can mitigate uncertainty over prices.³ A key question relating to this issue is the extent to which either the auction reserve price or containment reserve price are likely to be relevant, that is, the probabilities that market prices may be near the auction reserve price or the containment price.

In this paper we develop estimates of the range of allowance prices and the probabilities that one of the price containment mechanisms may be binding. A key factor driving these probabilities is the supply of abatement in California, which is likely to be highly non-linear. We find that a large supply of abatement will be available at prices below or very close to the auction reserve price, and as we argue below relatively little additional abatement will be available until price rises high enough to trigger sales from the price containment reserve. This abatement supply function, in turn, implies a bi-modal distribution of prices most of the probability mass at low or high price outcomes. The other critical factor is the relatively high degree of uncertainty surrounding expected “business as usual” (BAU) emissions that would result if there were no GHG reduction policies. In this paper we develop estimates of the range of BAU emissions utilizing forecasting techniques adapted from time-series econometrics, which we apply to emissions and economic data from 1990-2012 in order to forecast future emissions and the uncertainty of emissions.

Our empirical assessment of the potential demand for emissions allowances and supply of abatement and offsets suggests that the most likely outcome in the market will be a price very close to the auction reserve level.⁴ In what we view as the most plausible scenario, we find an 80% probability of such an outcome. In all of the scenarios we examine, however, we find a very low probability that the price will be in an intermediate range, substantially above the auction reserve level, but below the containment reserve prices. Thus, most of the remaining probability weight is on outcomes in which some or all of the allowances in the price containment reserve are needed. Throughout this analysis, we assume that no market participant is able to exert market power or manipulate the market for emission allowances. That is, we assume at this point

² The regulations are available at: http://www.arb.ca.gov/cc/capandtrade/september_2012_regulation.pdf.

³ See the ARB Board resolution dated October 18, 2012 at <http://www.arb.ca.gov/cc/capandtrade/final-resolution-october-2012.pdf> and an issue analysis from the Emissions Market Assessment Committee dated September 20, 2012 at <http://www.arb.ca.gov/cc/capandtrade/emissionsmarketassessment/pricecontainment.pdf>.

⁴ Throughout this paper we will refer to an “allowance market.” The trading of allowances and their derivatives will be arranged through several competing and coexisting platforms – including quarterly auction of allowances by the State. We assume that prices between these markets will be arbitrated so that all trading platforms will reflect prices based upon the overall aggregate supply and demand of allowances and abatement.

that the emissions market is completely competitive, that no market participant is able unilaterally, or collusively, to profitably change their supply or demand in order to alter the market price. In ongoing work, we are analyzing the potential for market power and market manipulation given the characteristics of supply and demand in the market.

The remainder of this analysis proceeds as follows. Section II gives an overview of the possible outcomes in the market for California emissions permits given the characteristics of supply and demand. Section III describes how we estimated BAU GHG emissions forecasts (and associated standard errors) for 2013-2020. Section IV assesses the supply of abatement related to complementary policies. Section V analyzes the supply of abatement related to the potential “reshuffling” of electricity purchases among buyers and sellers, also known as “resource shuffling.” Section VI assesses the supply of abatement related to offsets. Section VII assesses the supply of abatement related to price responsiveness. Section VIII compares BAU GHG emissions forecasts to the likely supply of relatively low-cost abatement and estimates the probability that the price containment reserve will be exhausted under various scenarios. We conclude in Section IX.

II. CALIFORNIA GHG CAP AND TRADE SUPPLY/DEMAND ECONOMICS

We focus on estimating the potential range and uncertainty of allowance prices over the 8-year span of the market. Fundamentally, the range of potential allowance prices is driven by the potential supply and demand for abatement of emissions. The underlying source of demand for allowances will be emissions of GHGs from the covered sources. The need for abatement will be determined by the difference between GHGs emissions under an uncapped (zero-price) BAU and the number of allowances issued under the program. Banking and borrowing of allowances is permitted among the years of each compliance period and banking is permitted between compliance periods, so the eight years of the market should be economically integrated. As a result, we examine the total supply and demand balance over the entire 8-years of the program (2013-2020). Because there is a large degree of uncertainty around the level of BAU emissions, we pay particular attention to establishing confidence intervals for these levels.

The number of allowances available in the California GHG cap and trade program derives from the allowance cap, a portion of which is allocated to a price containment reserve.⁵ Of the 2,508.6 MMT of allowances in the program over the 8-year period, 121.8 MMT of allowances are assigned to the price containment reserve to be made available in equal proportions at allowance prices of \$40, \$45, and \$50 in 2013. These price levels then increase each year at 5% plus the rate of inflation in the prior year.

The supply of abatement is multi-faceted and features several elements that are either unique, or present in a more extreme form, in California. These elements combine to create an extremely non-linear abatement supply curve, which we will demonstrate implies the potential for a wide-range of price outcomes. Abatement of capped emissions will flow through two mechanisms: a direct effect in which firms or consumers reduce emissions in response to a level

⁵ The price containment reserve is funded as follows: 1% of the allowance cap in each of 2013 and 2014, 4% of the allowance cap in each of 2015, 2016, and 2017, and 7% of the allowance cap in each of 2018, 2019, and 2020.

of allowance prices, and an independent effect in which emissions are reduced as a consequence of policies outside of the setting of the cap. These outside policies are often called “complimentary policies” in California.

The supply of relatively price-independent abatement comes from (a) programs that abate GHGs independent of the price in the market (often called “complementary policies”), (b) activities that reduce measured GHGs due to the process of accounting for electricity imports (“reshuffling” and “relabeling”⁶), and (c) offsets (which might be considered a form of lessening demand rather than increasing supply, but the analysis would be unchanged). While incentives for reshuffling and offsets are affected by the price of allowances, previous analyses suggest that the impact of allowance prices is likely to be small over the range between the auction reserve price and the prices at which allowances are made available from the price containment reserve.

In its revised scoping plan of 2010, ARB’s preferred model projects that 63% of emissions abatement would arise from complimentary policies rather than responses to the cap (four additional sensitivity models project between 30% and 63% of emissions abatement would arise from complementary policies).⁷ Translating these sources of abatement into a traditional supply curve format produces a large quantity of abatement that would arise *at any permit price*. In other words, even at the auction reserve price, there is a very large quantity of abatement – with an accompanying range of uncertainty – provided. It is important to recognize that these reductions are not costless, indeed many may impose costs above the allowance price. Rather, these reductions, and the accompanying costs, will occur independent of the level of the permit price. Therefore, while these policies provide reductions, and contribute to the goal of keeping emissions under the cap, they do not provide the price-responsive abatement that can help mitigate volatility in allowance prices.

As described below, the supply of price-responsive mitigation is limited by the allocation policies that have been implemented under AB 32. The large amount of allowances allocated using an approach known as output-based updating is expected to limit the impact of allowance prices on production levels and consumer prices for many industries.⁸ Most of the remaining reductions in response to allowance prices would therefore come from consumer responses to changes in energy products, namely transportation fuels (gasoline), natural gas, and, possibly, electricity consumption. Compared to the aggregate level of reductions needed and expected under AB 32, the reductions from these energy price effects are relatively small.⁹

The combination of large amounts of “zero-price” abatement, and relatively modest price-responsive abatement creates a hockey stick shaped, abatement-supply curve (See Figure

⁶ Relabeling describes the practice of reselling out-of-state power that comes from a high-emissions source such that the buyer can then import the power into California at the administratively determined default emissions rate.

⁷ See http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf at page 38 (Table 10).

⁸ Output-based updating of allocations serves to dilute the incidence of the allowance price on firms and consumers (see Meredith Fowle, “Updating the Allocation of Greenhouse Gas Emissions Permits in a Federal Cap-and-Trade Program,” in Don Fullerton and Catherine Wolfram, ed. *The Design and Implementation of U.S. Climate Policy*, University of Chicago Press. 2012.. If applied to a large enough set of industries or fraction of the allowances, the effect can be to inflate permit prices as higher prices are necessary to offset the diluted incentive to pass the carbon price through to consumers. (See Bushnell, James and Yihsu Chen. “Regulation, Allocation, and Leakage in Cap and Trade Markets for CO₂.” *Resources and Energy Economics*. 34(4), 2012.

⁹ Offsets and reshuffling/relabeling may also be sensitive to allowance prices, but are considered separately.

1). Analysis undertaken by ARB indicates that the marginal abatement cost curve rises sharply after the relatively low-cost abatement options are exhausted. ARB states in its updated Scoping Plan dated March 2010 that "...GHG emissions in the model show limited responsiveness to allowances prices... This lack of responsiveness results from the limited reduction opportunities that have been assumed to be available in the model."¹⁰ As a result of the sharp increase in marginal abatement costs, the marginal abatement cost curve is expected to be shaped more like a hockey stick than the canonical gently upward sloping curve that is often seen in economic textbooks when illustrating a marginal abatement cost curve.

One implication of this is that allowance prices are more likely to be either at or near the level of the auction reserve price or at levels set by the containment reserve policy than they are to fall at some intermediate level. When one considers an uncertain range of BAU emissions, even if strongly centered on the expected level, the probabilities of prices falling at either the ceiling or auction reserve price constitutes a large fraction of the overall distribution of potential emissions outcomes.

This intuition is illustrated in Figure 2, which superimposes a hypothetical symmetric distribution of the amount of abatement needed (BAU emissions less the cap) onto the same horizontal axis as our supply curve. Note from Figure 2 that the range of abatement quantity that falls between the auction reserve price (\$10.50/a ton in this illustration) and the price-containment "ceiling" (\$50/ton in this illustration), which is the area with no pattern, is relatively small.

The implications of California's abatement supply is therefore that the vast majority of probability for a given price outcome falls either at the auction reserve price or in the range in which the price containment policy is likely to be triggered. Rather than the familiar bell-shaped distribution of expected prices, it is more appropriate to think of the probabilities as distributed according to the dashed line of Figure 3, which has the same mean as the solid line, but this mean is generated by a high probability of a "low" (auction reserve) price balanced by a somewhat lower probability of a "high" (price containment reserve) price.

III. ESTIMATES OF BUSINESS AS USUAL EMISSIONS

Perhaps the largest factor driving the supply/demand balance in the GHG market will be the level of emissions that would take place under BAU. There is, however, considerable uncertainty about BAU emissions over the period 2013 to 2020. To derive estimates of the expected future time path of GHG emissions and the associated uncertainty associated with this forecast, we estimate a Vector Autoregression (VAR) model for the 3 major components of state-level GHG emissions and the key statewide factors that impact the level and growth of GHG emissions.¹¹ Due to the short time period for which the necessary disaggregated GHG

¹⁰ Available at: http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf. See also, the ARB analysis contained in Appendix F: Compliance Pathways Analysis available at: <http://www.arb.ca.gov/regact/2010/capandtrade10/capv3appf.pdf>.

¹¹ Vector Autoregressions are the econometric methodology of choice among analysts to construct short to medium-term (from 1 to 10 time periods into the future) forecasts of macroeconomic variables and for this reason are ideally suited to our present task.

emissions data have been collected, the model estimation is based on annual data from 1990 to 2010. Because data is available for 2011 and 2012 on real Gross State Product (GSP) in California, we condition on these values in forecasting the expected future time path of state-level GHG emissions and the uncertainty in the future time path.

Several features of our VAR model are chosen to match the time series relationships between the nine variables implied by economic theory and existing state policies to limit GHG emissions. We allow for the fact that all nine variables exhibit net positive or negative growth over our sample period and model them as stochastic processes that are 2nd-order stationary in growth rates rather than 2nd-order stationary in levels. We also impose restrictions on the parameters of the VAR model implied by the co-integrating relationships between these nine variables that are supported by the results of preliminary hypothesis tests. As shown by Engle and Yoo (1987) imposing the parameter restrictions implied by co-integrating relationships between variables in VAR model improves the forecasting accuracy of the estimated model.¹² Finally, we chose the variables that enter our 9-dimensional VAR to allow us to restrict the GHG emissions intensity of major fossil fuel-consuming activities in California in constructing forecasts of future GHG emissions.

Model

Let $X_t = (X_{1t}, X_{2t}, \dots, X_{9t})'$ denote the vector composed of the nine annual magnitudes included in the VAR for year t , $t=1990, 1991, \dots, 2010$. The elements of X_t are:

$X_{1t} = [(\text{Industrial GHG Emissions})/(\text{Natural Gas and Other GHG Emissions})]$

$X_{2t} = [(\text{Industrial GHG Emissions} + \text{Natural Gas and Other GHG Emissions})/\text{Real State GSP}]$

$X_{3t} = [\text{Total Vehicle Miles Traveled}]$

$X_{4t} = [\text{Total In-state Electricity Production in Terawatt-hours}]$

$X_{5t} = [\text{Real State GSP}]$

$X_{6t} = [\text{Real Oil Price in dollars per barrel}]$

$X_{7t} = [\text{Transportation Sector GHG Emissions}/\text{Total Vehicle Miles Traveled}]$

$X_{8t} = [\text{In-state Electricity Sector GHG Emissions}/\text{Instate Electricity Production}]$

$X_{9t} = [\text{In-state Electricity Consumption in Terawatt-hours}]$

All real dollar magnitudes are expressed in 2005 dollars. All GHG emissions are in Tons of CO₂-equivalents. GSP captures the empirical regularity--observed both over time and across jurisdictions--that a higher level of economic activity leads to greater energy consumption and GHG emissions. We include factors that lead to the consumption of fossil fuels such as in-state electricity production, total vehicle miles traveled, and in-state electricity production. We model the GHG emissions intensity of in-state electricity production, total vehicle miles traveled and

¹² Engle, Robert F., and Yoo, Byung Sam (1987) "Forecasting and Testing in Co-Integrated Systems," *Journal of Econometrics*, 35, 143-159.

real state GSP because we expect that state policies to limit GHG emissions are likely to impact these intensities, whereas the other variables are likely to continue to grow as the California economy grows. We do not include the GHG emissions content of electricity imports because this is largely an administratively determined number, because as a matter of physics, it is impossible to measure the GHG emissions content of electricity imports. All that can be measured is the aggregate GHG emissions outside of California and total electricity produced outside of California.

Define $Y_{it} = \ln(X_{it})$ for $i=1,2,\dots,9$ and $Y_t = (Y_{1t}, Y_{2t}, \dots, Y_{9t})'$. In terms of this notation a first-order autoregression or VAR that is stationary in first-differences can be written as

$$\Theta(L)Y_t = \varepsilon_t \quad (3.1)$$

where L is the lag operator which implies, $L^k Y_t = Y_{t-k}$, I is a (9×9) identity matrix, $\Theta(L)$ is (9×9) matrix function in the lag operator equal to $(I - \Theta_1 L - \Theta_2 L)$ where each Θ_i ($i=1,2$) is a (9×9) matrix of constants, and ε_t is a (9×1) white noise sequence with (9×1) mean vector μ and (9×9) covariance matrix Ω . Recall that white noise series are uncorrelated over time. In terms of the lag operator notation $(1-L) = \Delta$, so that $\Delta Y_t = Y_t - Y_{t-1}$.

Although model (3.1) allows each element of Y_t to be non-stationary, reflecting the fact that each element exhibits net positive or negative growth over the sample period, economic theory suggest that certain linear combinations of the elements of Y_t are likely to be 2nd-order stationary in levels. Times series processes that are 2nd-order stationary in first-differences (i.e., ΔY_t is 2nd-order stationary) that have stationary linear combinations of their elements are said to be co-integrated. That is because stochastic processes that are stationary in first-differences are also called integrated process with the order of integration equation equal to 1. The number of stationary linear combinations of the elements of Y_t is called the co-integrating rank of the VAR that is 2nd-order stationary in first-differences. The co-integrating rank is also equal to the rank of the matrix $(I - \Theta_1 - \Theta_2)$.

The existence of co-integrating relationships between elements of Y_t imposes restrictions on the elements of Θ_1 and Θ_2 . Suppose that the rank of the matrix $(I - \Theta_1 - \Theta_2)$ is equal to r ($0 < r < 9$), the number of stationary linear combinations of the elements of Y_t . This implies that the following error correction representation exists for Y_t :

$$(I - \Lambda L)\Delta Y_t = -\gamma Z_{t-1} + \varepsilon_t \quad (3.2)$$

where $Z_t = \alpha' Y_t$ is a $(r \times 1)$ vector of 2nd-order stationary random variables and γ is a $(9 \times r)$ rank r matrix of parameters and α is a $(9 \times r)$ rank r matrix of co-integrating vectors, Λ is a (9×9) matrix of parameters and $(I - \Theta_1 - \Theta_2) = \gamma \alpha'$.

Johansen (1988) devised a test for the co-integrating rank of a VAR that is 2nd-order stationary in first-differences.¹³ Applying this test to Y_t finds that the null hypothesis that r , the rank of $(I - \Theta_1 - \Theta_2)$, is 3 can be rejected at a 0.05 level, yet the null hypothesis that r , the rank of $(I - \Theta_1 - \Theta_2)$ is 4, cannot be rejected at a 0.05 level. This hypothesis testing result is consistent with the existence of 4 stationary linear combinations of the elements Y_t . We impose these co-

¹³ Johansen, S. (1988) "Statistical Analysis of Cointegration Vectors," Journal of Economic Dynamics and Control, 12, 231-254.

integrating restrictions on the parameters of VAR model (3.1) that we estimate to forecast future GHG emissions.

Our estimation procedure yields consistent, asymptotically normal estimates of μ , Ω , and Θ_1 and Θ_2 with the co-integrating restrictions imposed. Using these parameter estimates we can then compute an estimate of the joint distribution of $(X_{2013}, X_{2013}, \dots, X_{2020})'$ conditional on the values of (X_{2009}, X_{2010}) that takes into account both our uncertainty in the values of μ , Ω , Θ_1 , Θ_2 because estimation error and uncertainty due to the fact that $(X_{2013}, X_{2013}, \dots, X_{2020})'$ depends on future realizations of ε_t for $t=2011, 2012, \dots, 2020$. Because we have values for Real State GSP for 2011 and 2012, we compute our estimate of the distribution of $(X_{2013}, X_{2013}, \dots, X_{2020})'$ conditional on these values as well as the observed values of (X_{2009}, X_{2010}) .

We employ a two-stage smoothed bootstrap approach to compute an estimate of this distribution. The first step computes an estimate of the joint distribution of the elements of μ , Ω , and Θ_1 and Θ_2 sampling from the smoothed empirical distribution of the (9×1) vector of residuals from the estimated Vector Error Correction Model (VECM). Let $\hat{\mu}$, $\hat{\Omega}$, $\hat{\Theta}_1$, and $\hat{\Theta}_2$ equal the estimates of the elements of the VECM. Compute

$$Y_t - \hat{\Theta}_1 Y_{t-1} - \hat{\Theta}_2 Y_{t-2} = \hat{\varepsilon}_t \quad (3.3)$$

for $t=1990$ to 2010 . Construct the smoothed kernel density estimate of the $\hat{\varepsilon}_t$ as

$$\hat{f}(t) = \frac{1}{Th^9} \sum_{t=1}^T K\left\{\frac{1}{h}(t - \hat{\varepsilon}_t)\right\} \quad (3.4)$$

where T is the number of observations, h is a user-selected smoothing parameter, and $K(t)$ is a multivariate kernel function that everywhere positive and integrates to one. We use the multivariate normal kernel

$$K(x) = \frac{1}{(2\pi)^{9/2}} \exp\left(-\frac{1}{2}x'x\right) \text{ where } x \in \mathbb{R}^9.$$

and $h=0.5$, and we found that are results were insensitive to the value chosen for h , as long as it was less than 1.

We then draw $T=19$ values from the (3.4) and use the parameter estimates and these draws to compute re-sampled values of Y_t for $t=1, 2, \dots, T=19$. Let $(\hat{\varepsilon}_1^m, \hat{\varepsilon}_2^m, \dots, \hat{\varepsilon}_{19}^m)'$ denote the m^{th} draw of the 19 values of $\hat{\varepsilon}_t$ from $\hat{f}(t)$. We compute the 19 resampled values of Y_t by applying the following equation starting with the values of Y_t in 2000 and 2001.

$$Y_t^m = \hat{\Theta}_1 Y_{t-1}^m + Y_{t-2}^m \hat{\Theta}_2 + \hat{\varepsilon}_t^m \quad (3.5)$$

We then estimate the values of μ , Ω , Θ_1 , Θ_2 using the Y_t^m . Call the resulting estimates $\hat{\mu}^m$, $\hat{\Omega}^m$, $\hat{\Theta}_1^m$, and $\hat{\Theta}_2^m$. Conditional on these values of we then draw ten values from $\hat{f}(t)$. Call the b^{th} sample of these values $(\hat{\varepsilon}_{T+1}^{mb}, \hat{\varepsilon}_{T+2}^{mb}, \dots, \hat{\varepsilon}_{T+10}^{mb})'$. Using these draws and $\hat{\mu}^m$, $\hat{\Omega}^m$, $\hat{\Theta}_1^m$, and $\hat{\Theta}_2^m$ compute future values Y_{T+k} given Y_T and Y_{T-1} .

$$Y_{T+k|T, T-1}^{bm} = \hat{\Theta}_1^m Y_{T+k-1|T, T-1}^{bm} + \hat{\Theta}_2^m Y_{T+k-2|T, T-1}^{bm} + \hat{\varepsilon}_{T+k}^{mb} \text{ for } k=1, 2, \dots, 10. \quad (3.6)$$

This yields one realization of the future sample path of Y_t for $t=2011, 2012, \dots, 2020$. The elements of Y_t can then be transformed to X_t by applying the transformation $X_{it} = \exp(Y_{it})$ to each element of Y_t to yield a realization of the future time path of X_t . The elements of X_t are then transformed produce a realization of the future time path of GHG emissions by each covered sector. We repeat the first step of the process $m = 1$ to $M=500$ times and conditional on each value of $\hat{\mu}^m, \hat{\Omega}^m, \hat{\Theta}_1^m$, and $\hat{\Theta}_2^m$ we repeat the second simulation of future values of Y_t for $t=2010$ to 2020 , $b=1$ to $B=500$ time to produce 250,000 realizations from the simulated distribution of $(X_{2010}, X_{2011}, \dots, X_{2020})'$. By increasing M and B , we can also compute a simulated distribution $(X_{2013}, X_{2014}, \dots, X_{2020})'$ that conditions on the values of real state GSP in 2011 and 2012, by simply restricting for consideration sample paths with $(X_{2013}, X_{2014}, \dots, X_{2020})$ where the realized values of real state GSP in 2011 and 2012 lie in a small intervals around the values in 2011 and 2012.

Because of our concern that state policies to reduce GHG emissions would likely limit the GHG emissions intensity of total vehicle miles traveled, in-state electricity production and real state GSP, we impose upper bounds on these three GHG emissions intensity measures. This was accomplished by truncating realizations of the value of these intensity figures in computing the future time path of GHG emissions. For example, if a realization of a GHG emissions intensity in any realization of the two-step process of computing the joint distribution of $(X_{2013}, X_{2013}, \dots, X_{2020})'$ exceeds our upper bound, we re-set the value of that intensity for that year to our upper bound to compute GHG emissions for that sector for that year. For example, if the realization for certain values m and b of $(\text{GHG Emissions from the Transportation})/(\text{Total Vehicle Miles Traveled})$ exceeds the upper bound for that year, the realized value for GHG Emissions from Transportation would be set equal to that upper bounds times the realized value of Total Vehicle Miles Traveled. Similar procedures were followed using the other two intensity measures to compute future GHG emissions from those covered sectors.

Because California's cap and trade program phases in the entities under the cap over time, our approach separately forecasts emissions from Phase I entities (narrow scope) and Phase II entities (broad scope). Phase I, in effect during the first compliance period, 2013 and 2014, covers electricity generation and emissions from large industrial operations. Phase II, in effect for the second and third compliance periods, 2015-2017 and 2018-2020, expand the program to include combustion emissions from transportation fuels, and emissions from natural gas and other fuels combusted at residences and small commercial establishments.

We do not forecast GHG emissions from electricity imports into California, because, as noted earlier, these are an administratively determined numbers based on the declared sources of supply of electricity imports. An additional reason to exclude electricity imports from the estimation is that the administrative process for determining the GHG emissions content of imports is still a subject of debate in the development of the market rules for what constitutes or does not constitute resource shuffling. Instead, we forecast future GHG emissions from in-state sources using each of the approaches described above and then add back in the administratively determined figures for electricity imports.

Data

Annual emissions levels for each covered sector are taken from the 1990-2004 Greenhouse Gas Emissions Inventory and the 2000-2010 Greenhouse Gas Emissions Inventory (hereafter, Inventory).¹⁴ The longest series of consistently measured emissions data and the basis for developing the 1990 statewide emissions level and 2020 emissions limit required by AB 32, ARB staff rely primarily on state, regional or national data sources, rather than individual facility-specific emissions. However, due to differences in accounting, the Inventory likely overstates emissions from industrial activity relative to those covered in the first compliance period of the cap and trade program. In particular, the Inventory methodology may attribute some emissions to the industrial sector – such as natural gas combustion from small industrial or commercial sources – that are not covered until the second compliance period. We investigate the impact of this difference by comparing the Inventory data to annual data collected under the Mandatory Reporting Regulation (MRR), the methodology used to calculate an entity’s compliance obligation under cap and trade.¹⁵ We did not find that either our expected time path or uncertainty in the time path were impacted by plausible adjustments in the values GHG emissions from each of the covered sectors during our sample period that were aimed at making these two data sources consistent.

Comparing 2008 to 2010 MRR and Inventory industrial emissions data shows annual differences of 8.98 to 12.48MMT with Inventory industrial emissions thirteen percent higher than MRR industrial emissions, on average. We address this difference by forecasting industrial capped source emissions in the first compliance period using the Inventory industrial emissions data series adjusted downward by thirteen percent. We use the unadjusted Inventory data as our measure of industrial capped source emissions covered in the second and third compliance periods. As our maintained assumption is that the first compliance period difference is due to differences in accounting, as opposed to classical measurement error, using the Inventory emissions estimates for the second and third compliance periods should not bias our emissions estimates upward.

Real California GSP – measured in millions of 2005 dollars – is collected from the Bureau of Economic Analysis (BEA).¹⁶ Real oil price are compiled United States Energy Information Administration as the annual average West Texas Intermediate (WTI) price at Cushing, Oklahoma.¹⁷ In-state electric generation and electricity consumption are collected from the California Energy Commission (CEC).¹⁸ Statewide on-road and off-road VMT are taken from ARB’s Mobile Source Emissions Inventory.¹⁹

Results

¹⁴ California’s GHG emissions inventory is available at: <http://www.arb.ca.gov/cc/inventory/inventory.htm>.

¹⁵ Information on the ARB mandatory reporting regulation is available at: <http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm>.

¹⁶ Gross Domestic Product by State is available at: <http://www.bea.gov/regional/index.htm#data>.

¹⁷ The nominal annual average West Texas Intermediate crude oil price in dollar per barrel is available at http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

¹⁸ In-state California generation and natural gas consumption are available from the CEC at <http://energyalmanac.ca.gov/electricity/index.html> and <http://energyalmanac.ca.gov/naturalgas/index.html>, respectively.

¹⁹ ARB’s mobile source emission inventory is available at: <http://www.arb.ca.gov/emfac/>.

To construct estimates of the cumulative total emissions covered by the program from 2013 to 2020 requires we combine forecasts of GHG emissions from Phase I facilities for 2013 and 2014 and GHG emissions from Phase II facilities for 2015 to 2020. The results are presented in Figure 4a (stationary in growth rates with GHG ratios to other factors bounded above at their median levels in the dataset), Figure 4b (stationary in growth rates with GHG ratios to other factors bounded above at the 75th percentile levels in the dataset) and Figure 4c (stationary in growth rates with GHG ratios to other factors bounded above at their maximum levels in the dataset). In all three Figures the solid line represents the estimated cumulative GHG emissions to that year and the dashed lines around it represent the 95% confidence interval. In all three Figures, the slope of the cumulative emissions increases after 2014 as a result of the expansion of covered entities.

IV. COMPLEMENTARY POLICIES

The ARB analysis identifies several categories of complementary policies, which, if they fully achieve expectations, would yield a savings of 87 MMT during the year 2020.²⁰ Of this total, 38 MMT were incorporated into ARB's BAU forecast of emissions in 2020. The reductions for the years prior to 2020 are unknown to us. For the purposes of this analysis, we assume these reductions come into effect linearly over time, ramping upward from zero in 2012 to 87 MMT in 2020.

With regard to the 38 MMT of reductions included in ARB's BAU, it is important to note that to the extent existing trends in activities such as renewable electricity development and energy efficiency are already reflected in historic data, the continuation of these trends will also be reflected in our BAU forecast due to the vector autoregression approach that would capture pre-existing trends. For example, the historic data demonstrate a declining ratio of energy consumption to GSP on average, and that trend is incorporated into the BAU forecasts through 2020. For this reason, in some instances, it may be double counting to subtract reductions from complementary measures that were already present during the early 2000s and have been ramped up through the last decade and are likely to continue to rise. In recognition of this, and the uncertain nature of future reductions, we offer a range of average annual emissions reductions for each of the complimentary policies. Our best estimates of emissions reductions from additional complementary measures not already reflected in our BAU estimates are summarized Table 1 and explained in more detail in the following subsections.

²⁰ Documentation for the 87 MMT emission reductions total – 38 MMT from Paveley I and 20% RPS and 49 MMT from all other Scoping Plan Measures – are available at: http://www.arb.ca.gov/cc/scopingplan/sp_measures_implementation_timeline.pdf and http://www.arb.ca.gov/cc/inventory/data/tables/reductions_from_scoping_plan_measures_2010-10-28.pdf.

Table 1: Potential Emissions Reductions from Complementary Policies

Complementary Measure	Average Annual Reductions (2013-2020, above prior trend)	Years Under Cap	Total Aggregate Reductions Under Cap
20% and 33% RPS	7.8 – 12.4 MMT	2013 – 2020	62.4 – 98.8 MMT
Auto Standards	9.3 – 16.2 MMT	2015 – 2020	74.2 – 129.8 MMT
LCFS	0 – 10.3 MMT	2015 – 2020	0 – 61.9 MMT
Energy Efficiency	0 – 3.4 MMT	2013 – 2020	0 – 27 MMT
Other transport	0 – 1.5 MMT	2015 – 2020	0 – 12.4 MMT

a. Renewable Portfolio Standard

In 2010, renewable supply was about 14% of consumed electricity, reflecting an upward trend from about 10% in the mid-2000s. We assume a range of combined compliance with the 20% and 33% RPS to yield renewable energy in a range from 26% to 33% of total electricity consumption by 2020. This is assumed to ramp up at a linear rate from 14% in 2010 to the end target in 2020. Given 2010 Emissions Inventory overall electricity sector emissions of 92.2 MMT, we assume each additional percentage point of renewable energy saves on average about 1 MMT/year.

We assumed an increase from 17.8% in 2012 to 33% in 2020 on the high end of the estimate. This produces an annual average value of 26.4% or an increase of 12.4% (translating to a decrease of 12.4 MMT/year) from 2010 levels.

Following a similar methodology for the low-end estimate of 26% in 2020 produces an annual average reduction of 7.8 MMT/year. Total 8-year reductions are calculated by multiplying these annual average values by 8. The resulting range is therefore **62.4-98.8 MMT**.

b. Fuel Economy and Advanced Auto Standards

ARB staff estimates annual impact of 29.9 MMT from the combination California's "Pavley" fuel economy standards and advanced auto standards. Our understanding is that the latter standard has not yet been adopted. We therefore consider achieving this reduction to be less certain. We also adjust the impact downward to account for the interaction between the auto standards and the Low Carbon Fuel Standard (LCFS), which estimates an increase of non-petroleum fuels (most not under the cap) from 10 to 18% between 2010 and 2020. While we consider this last estimate aggressive, we adjust the auto impact downward to account for the fact that more of the fuel *not* consumed would not be otherwise covered under the cap. We assume full compliance with both standards to be the upper bound on savings, and assume a lower bound in which these standards are instead replaced by Federal CAFE standards. The resulting range of reductions is assumed to be 16 to 28 MMT in 2020 -- and ramping up linearly to these levels from 2012 levels -- which translates to a savings from 2015 to 2020 (fuels not being under the cap in earlier years) of **74.2 – 129.8 MMT**.

c. Low Carbon Fuel Standard

The LCFS would implement carbon reductions in two ways: increasing the percentage of low-carbon (non-petroleum) fuels and reducing the carbon content of the mix of non-petroleum fuels already consumed. Since all biofuels will be treated as zero carbon under the cap and trade program, only the former reductions would create savings under the accounting of the cap. Our understanding of ARB assumptions is that 15 MMT of reductions assumed to be achieved in 2020 stems from an increase of non-petroleum fuel mix from 10% to 18%. We consider the 18% to be an upper bound of the achievable range. Given the current uncertainty surrounding the ethanol blend-wall the willingness of stations to carry higher percentage mixes, we consider the assumed 10% mix to be a lower-bound. From the fuels consumption implied in our baseline, the Pavely standards would reduce the consumption of total fuels and we adjusted the impact of the LCFS accordingly. Our range of LCFS savings *under the cap* is therefore **0 – 61.9 MMT**.

d. Energy Efficiency Measures

With California's longstanding commitment to energy efficiency, we believe that a strong pre-existing trend of efficiency improvements is already present in the time-series data we used to forecast the BAU emissions. We are therefore concerned that further reductions from BAU for energy efficiency improvements would double count those reductions. We assume that savings under the cap range from **0 – 27 MMT**, where the high-end estimate assumes a 2020 reduction (above trend) of 6 MMT/year.

e. Other Transport

Other Transport includes complementary measures associated with regional targets (SB 375, which calls for sustainable community planning), tire pressure program, heavy duty aerodynamics as well as medium and heavy duty hybridization. ARB attributes 4.5 MMT of emission reductions to these programs in 2020. We assume that savings under the cap for these four combined measures ramp up linearly, creating a potential range from **0 – 12.4 MMT**.

V. RESHUFFLING AND RELABELING

ARB has attempted to include all emissions from out-of-state generation of electricity delivered to and consumed in California under the cap and trade program's GHG accounting framework. However, due to the nature of the Western Interconnection, it is often impossible to identify the source of generation supplying imported electricity. Electricity importers therefore have an incentive to engage in a variety of practices that lower the reported GHG content of their imports, a class of behaviors broadly labeled reshuffling. While reshuffling would not yield aggregate emissions reductions in the Western Interconnection, it could be a major source of measured emissions reductions under the cap and trade program.

ARB projects annual BAU emissions from imported electricity of 53.5 MMT, during the period 2013-2020. Under one extreme, importers could reshuffle all imports to GHG free resources, creating cumulative emissions reductions of 428.3 MMT. ARB may limit reshuffling

by targeting imports from utility-owned coal plants, which are expected to account for 92.2 MMT during the eight-year period. However, we do not treat 336.1 MMT (full reshuffling less utility-owned coal imports) as the upper bound on reshuffling, because utility divestiture of a coal resource may not be considered reshuffling, regardless of the coal resource's future generation profile. Recognizing that additional soft uncertainties such as contracting costs, institutional inertia, and preferences of owners to maintain property rights to GHG free sources may impede full reshuffling, we put an upper bound on reshuffling at 360 MMT.

For a lower bound we first consider the difference between ARB's BAU estimates and 2009-2011 MRR emissions data. As ARB's BAU estimate was made without consideration of reshuffling, this difference in emissions associated with imports is likely a reasonable approximation of the minimum amount of costless reshuffling immediately available to the electric sector. The 2009-2011 MRR emissions data show an average reduction of 7.6 MMT from imported electricity emissions relative to ARB's BAU. If persistent, this would result in 60.8 MMT of emissions reductions through 2020. Additionally, the utilities have a number of long-term coal contracts that they are eligible to terminate under SB 1368. Replacing those coal contracts with unspecified power (which is administratively assigned 0.428 MMT/MWh) or GHG-free resources would result in cumulative reductions of 38.2 MMT and 78.3 MMT, respectively. In consideration of similar soft uncertainties arising from market frictions we choose a lower bound for reshuffling of 120 MMT. The resulting range of reshuffling is therefore **120-360 MMT**.

VI. OFFSETS

The cap and trade program permits a covered entity to meet its compliance obligation with offset credits equal to eight percent of its annual and triennial compliance obligations. ARB has approved four categories of compliance offset projects that can be used to generate offsets – U.S. Forest and Urban Forest Project Resources Projects; Livestock Projects; Ozone Depleting Substances Projects; and Urban Forest Projects. Each individual offset program is subject to a rigorous verification, approval, and monitoring process. The California ARB has approved two offset project registries – American Carbon Registry²¹ and the Climate Action Reserve²² –to facilitate the listing, reporting, and verification of specific offset projects. The Climate Action Reserve reports there are approximately 11.5 million existing offsets that were generated under a voluntary early action offset program overseen by the Climate Action Reserve that are eligible for conversion to cap and trade program compliance offsets.²³

Offsets are expected to be a relatively low-cost (though not free) means for a covered entity to meet a portion of its compliance obligation.²⁴ The number of offsets expected to be available in the cap and trade program is subject to a high degree of uncertainty and best guesses put the estimate substantially below the potential number of offsets that could be used (i.e., 8% of compliance obligations). One recent third-party study from September 2012 estimates the number of offsets available under all four protocols between 2013 and 2020 at 66 MMT, only

²¹ See <http://americancarbonregistry.org/carbon-accounting/california-compliance-offsets>.

²² See <http://www.climateactionreserve.org/>.

²³ Data collected from the "listed projects" tab at <http://www.climateactionreserve.org/>.

²⁴ <http://www.arb.ca.gov/regact/2010/capandtrade10/capv3appf.pdf>.

30% of the nearly 220 MMT of offsets that theoretically could be used to satisfy compliance obligations.²⁵ As a result of this anticipated shortfall, we understand ARB has considered adding two additional offset protocols – Rice Cultivation and Coal Mine CH₄ Capture and Destruction. The addition of these two protocols is estimated to make an additional 64 MMT of offsets available (for an estimated total of 130 MMT) between 2013 and 2020.²⁶

For the purposes of our analysis, we assume the cumulative number of offsets available between 2013 and 2020 range between **75 MMT and 139 MMT**.²⁷

VII. PRICE-SENSITIVE ABATEMENT

As the price of allowances rises, in some areas the increased cost will change consumer and producer behavior. In order to assess the potential abatement supply in the cap and trade market, we consider such price-elastic supply in four areas on the consumer side: demand for gasoline, diesel, electricity and natural gas. We also consider electricity generation and industrial emissions. For each of these areas, we calculate the abatement that would occur with the price at the auction reserve price, at the price to access the first tier of the containment reserve, and at the price to access the third tier of the containment reserve.²⁸

a. Demand for Fuels

The potential impact of the allowance price on consumption of gasoline and diesel is a function of short-run effects, such as driving less and switching among family cars, and longer-run effects, such as buying more fuel-efficient cars and living in areas that require less use of an auto. If, however, fuel-economy standards have pushed up the average fuel economy of vehicles above the level consumers would otherwise choose (given fuel prices), then raising fuel prices will have a smaller effect, because the fuel-economy regulation has already moved them into the automobile fuel economy they would have chosen in response to higher gas prices. For this reason, in jurisdictions with effective fuel-economy standards, such as California, the price-elasticity of demand for fuels is likely to be low. Short-run price elasticity estimates are generally -0.1 or smaller (in absolute value).²⁹ Long-run elasticities are generally between -0.3 and -0.5.³⁰ Furthermore, the fuel-economy standards would also reduce the magnitude of emissions reductions by lowering the baseline level of emissions before the price of allowances has an effect, which we account for in our analysis of complementary policies.

We recognize that improved fuel economy standards will phase in gradually during the cap and trade compliance periods. To balance these factors, we assume the baseline level of

²⁵ <http://americancarbonregistry.org/acr-compliance-offset-supply-forecast-for-the-ca-cap-and-trade-program>.

²⁶ <http://americancarbonregistry.org/acr-compliance-offset-supply-forecast-for-the-ca-cap-and-trade-program>.

²⁷ The analysis described in this document assumes a single eight-year compliance time horizon. As a result, the analysis does not address the fact that any shortfall of offsets in earlier compliance periods cannot be recaptured in later time periods and thus results in a permanent shortfall in offsets from the theoretical potential.

²⁸ Each of these price levels escalates over time in real terms, so we calculate the price-sensitive abatement for each year separately.

²⁹ See Hughes, Jonathan E., Christopher R. Knittel and Daniel Sperling, “Evidence of a Shift in the Short-Run Price Elasticity of Gasoline.” *The Energy Journal*, 29(1), January 2008.

³⁰ See Dahl, Carol A., “Measuring global gasoline and diesel price and income elasticities” *Energy Policy*, 41(1), 2012, pp. 2-13.

emissions is unchanged, but that the price elasticity of demand will be -0.1. At the highest price in the price containment reserve in each year (which is \$50 in 2013 going up to \$70.36 in 2020), the result is a reduction of **13.4 MMT** over the life of the program from reduced use of gasoline and diesel. Assuming an elasticity of -0.2 about doubles the reduction to **26.7 MMT**. (Note the fuels will be under the cap only in 2015-2020, so we calculate reductions for only these six years.)

b. Demand for Electricity

The impact of a rising allowance price on emissions from electricity consumption depends primarily on the pass-through of allowance costs to retail prices of electricity. A best guess seems to be that there will be little or no pass-through of allowance prices to customers, because utilities will be receiving free allocations that will offset their allowance obligations. Although in theory it is possible that utilities could raise marginal price and use the revenue from the free allocations to lower a fixed charge, in practice this seems very unlikely. It is particularly unlikely because other factors, primarily increased renewables penetration, are likely to be pushing up costs and prices independent of the cap and trade program, though cheap natural gas may mitigate this impact somewhat. Taking an average statewide retail electricity price of \$120/MWh, assuming that this increases by \$20 due to exogenous (to cap and trade) factors and assuming a demand elasticity of -0.2 and a marginal CO₂e intensity of 0.428 MT/MWh, yields a reduction of **24.4 MMT** at the highest price in the price containment reserve over the life of the program. Both the elasticity and the CO₂e intensity figures are probably a bit on the high side, so a low-scenario figure would be **15 MMT**. Whichever figure is used, we include this in the price-inelastic abatement figure, because the reduction is likely to result from the impact of complementary renewables policies on retail rates and, thus, would be independent of the price of allowances.

c. Demand for Natural Gas

At this point, utilities are not scheduled to receive free allocation of allowances for their natural gas sales and the allowance cost is expected to be passed through to consumers. “Consumers” in this case include all emissions sources not covered in the industrial categories. Large industrial customers are in the program during the first compliance period. We assume a baseline emissions rate of 49.7 MMT/year for each of the six years that non-industrial customers are in the program. We assume an average retail price of \$9/MMBTU across all nonindustrial types of natural gas customers (residential is a bit over \$10, small commercial about \$9, large commercial about \$7) and 100% pass-through of the allowance cost to retail. It’s difficult to know the elasticity of retail demand for natural gas. We take a low-end estimate of -0.2 and a high-end estimate of -0.4 over the 6-year time frame of natural gas in the program.³¹ Based on these assumptions, at the highest price in the price containment reserve, the low scenario estimated abatement is **18.5 MMT** and the high scenario is **35.8 MMT**.

d. Abatement from Out-of-State Electricity Dispatch Changes

³¹ Though some estimates of the price elasticity of gas and electricity demand are higher than those we use here, such estimates generally include substitution from gas to electricity and vice versa, which would have a much smaller net impact on emissions.

To the extent that some high-emissions out-of-state coal plants are not reshuffled or declared at the default rate, there is possible elasticity from higher allowance prices incenting reduced generation from such plants. We considered this, but the most recent reshuffling treatment from ARB suggests that incremental reshuffling from these plants will not be punished. If that is the case, then an operator would be better off reshuffling some of the power than actually reducing output from the plant. This suggests that some reshuffling may exhibit price elasticity. In any case, we consider that as part of the reshuffling and relabeling analysis.

e. Industrial Emissions

For the industries covered under output-based updating, there may still be some emissions reductions as the allowance price rises. This could happen in two ways. First, once a baseline ratio of allowances to output is established, these firms have an incentive to make process improvements that reduce GHG emissions for a given quantity of output. It is unclear how much of such improvement is likely to occur. At this point we have no information on this. Our current estimates assume this is zero, but further investigation of this factor is warranted. Second, because the output-based updating is not 100%, additional emissions that result from marginal output increases do impose some marginal cost on the firms. That impact is likely to be small, however, because the effective updating factors average between 75% and 90% over the program, which implies that the firm faces an effective permit price of 10% – 25% of the market price for emissions that are associated with changes in output. At this point, we have not incorporated estimates of this impact, but it seems likely to be quite small.

VIII. SUPPLY/DEMAND BALANCE UNDER ALTERNATIVE SCENARIOS

In order to compute the probabilities of different price outcomes in California's GHG market, we combine the BAU emissions forecasts generated from the models we estimated in Section III with scenarios for allowance, abatement and offset supply. We consider four mutually exclusive and exhaustive potential market clearing price ranges: (1) at or near the auction reserve price, without any access of the price containment reserve, and low-cost abatement and offset supply, (2) noticeably above the auction reserve price, without any access of the price containment reserve, with marginal supply coming primarily from price-elastic sources, (3) above the lowest price at which allowances would be available from the price containment reserve, but at or below the highest price of the price containment reserve, and (4) above the highest price of the price containment reserve.

We characterize price range (1) as "at or near" the auction reserve price, because the mechanism of the auction reserve price implies an uncertain economic price floor. The auction reserve price was set at \$10 per tonne for 2012 and then rising at 5% per year plus inflation. Setting aside the uncertainty of inflation, if investors' real cost of capital differs from 5%, then the effective economic price floor will not be the auction reserve price. If, for instance, investors' real cost of capital were 3% per year for an investment such as this, then the effective price floor today would be the present discounted value of the price floor in the last auction in which

allowances are sold.³² Thus, in any one year the effective economic price floor may differ somewhat from the auction reserve price.

As of this writing, the ARB is expected to implement new policies to address the possibility of the price containment reserve being exhausted. We do not address how high the price might go in case (4), which would be difficult to do even in the absence of this policy uncertainty, but in any case will be greatly influenced by the ARB's policy decisions scheduled to occur in the next year. We simply report the estimated probability of reaching this case.

Our analysis is in terms of real 2012 dollars, so there is no need to adjust for inflation, but the price trigger levels for the price containment reserve will, under current policy, increase at 5% in real terms every year. Thus, while the containment reserve is made available at prices from \$40-\$50 in 2013, the range escalates to \$56.28-\$70.35 in 2020 (in 2013 dollars). As we show below, the containment reserve prices are only likely to occur if BAU GHGs grow faster than anticipated over many years, so the relevant containment reserve prices are those that will occur in the later years of market operations, when such growth would become evident. For that reason, we use the 2020 price containment trigger prices for our analysis.

We consider BAU GHG emissions forecasts under the three different estimation approaches described in Section III and presented in Figures 1, 2, and 3: assuming GHG emissions are (a) stationary in growth rate with GHG ratios to the other variables bounded above at their median level of the 1990-2012 sample, (b) stationary in growth rate with GHG ratios to the other variables bounded above at their 75th percentile level of the 1990-2012 sample, and (c) are stationary in growth rate with GHG ratios to the other variables bounded above at their maximum level of the 1990-2012 sample.

While there are an infinite number of abatement and offset supply scenarios one might study, we present three scenarios that we consider to be reasonable and realistic. For each of the supply scenarios, we assume a fixed supply quantity from complementary measures, reshuffling, and offsets, and we assume a fixed elasticity of supply for each of the price-sensitive sources.

- 1) **Scenario 1, Low availability:** low/medium complementary measures (185 MMT), low/medium levels of reshuffling (180 MMT), low/medium offset availability (90 MMT), medium consumer response to prices (due to weak fuel efficiency standards in complementary measures)
- 2) **Scenario 2, Medium availability:** Medium complementary measures (233 MMT), medium reshuffling (240 MMT), medium offset availability (110 MMT), low consumer response to prices
- 3) **Scenario 3, High availability:** High/medium complementary measures (282 MMT), high/medium reshuffling (300 MMT), high/medium offset availability (123 MMT), medium consumer response to prices.

³² For example, if inflation were anticipated to be 2% per year, the nominal auction reserve price in 2020 would be \$17.18. If investors' anticipated some new sales of allowances in 2020 and their cost of capital was 3% per year, then the effective economic price floor in 2012 would be \$17.18 discounted back to 2012 at 5% per year, or \$11.63, rather than \$10.

We consider the medium availability scenario a good center of the possible outcomes. It is unlikely that all the low all the high cases for abatement and offset factors would occur, so we consider low/medium cases and high/medium cases as the bounds on likely outcomes in availability of abatement and offsets.

We put these together with the predetermined allowance supply available (not counting allowances in the price containment reserve) to determine the supply through 2020 at prices below the lower trigger price for the containment reserve. At prices between the lower and upper trigger price for the containment reserve, we also added in the available supply from the containment reserve.

We then combine the supply scenarios with the distribution of demand for greenhouse gas allowances under the three estimation methods discussed in Section III to determine the probabilities that the market outcome will fall in each of the four price ranges discussed above. Figure 5 shows these probabilities using each of the three demand estimation methods and each of the three supply scenarios.

We focus on the estimation method using the 75th percentile of sample bound for the ratio of GHG to other factors in the VECM and on the medium availability supply scenario, the middle case of the nine bars in Figure 5. That bar suggests that by 2020 there is an 80% probability that the allowance price will be at or near the auction reserve price, a 1% probability that it will be substantially above the auction reserve price, but still below the lowest price at which the containment reserve allowances can be sold, a 8% probability that the price will be within the range of the containment reserve, and an 11% probability that the containment reserve will be exhausted.

The other bars show the direction of variability: more supply raises the probability of a low price and lowers the probability of exhausting the containment reserve, and the low supply scenario has the opposite effect. There is little difference between the results of the demand estimation using the median GHG ratio to other factors as the upper bound and the results using the 75th percentile ratio as the upper bound. Using the maximum ratio at the upper bound substantially widens the possible demand outcomes and raises the probability of exhausting the containment reserve.

The results are consistent with the discussion in Section II. We conclude that there is a high probability that the market price will be near the auction reserve price in 2020, a small but significant probability that the price will be high enough to trigger release of some or all of the allowances in the price containment reserve, and very little chance that the price will be in the intermediate range where price-responsive abatement actions are the primary factor that balance of supply and demand.

IX. CONCLUSION

Economists have for decades advocated using market mechanisms to reduce pollution externalities. California has now embarked on a plan to reduce greenhouse gas emissions

through such a market mechanism, a cap and trade program. The prices that will result in the program will depend on the demand for the emissions allowances, resulting from firms and individuals who wish to engage in GHG-emitting activities, and the supply of both emissions allowances and the ability to reduce emissions.

We have shown that there is significant uncertainty in both the demand and supply in this market. Furthermore, it seems likely that the great majority of abatement supply that is available at prices below the price containment reserve level will be available at prices near the auction reserve. As a proportion of the market, our analysis indicates that fairly little additional supply will be forthcoming at prices substantially above the auction reserve price, but below the lowest price of the containment reserve. Combined with the uncertainty in the demand for allowances, this suggests that the market price is unlikely to fall in an intermediate range substantially above the auction reserve price, but still below the level at which allowances from the price containment reserve would be made available. Our analysis also suggests that there is a small, but not insignificant, chance that the demand for emissions allowances could exceed the available supply after accounting for abatement activity and the supply of emissions offsets. This possibility supports the view expressed by ARB in October 2012 that it is prudent to pursue further policies that would prevent the price from skyrocketing if demand for emissions allowances turned out to be much stronger than expected.

It is important to note that the scenarios under which the price for emissions could climb very high by 2020 may not produce high prices in 2013. High prices towards the end of the program would result from unexpectedly strong demand and/or low abatement/offset supply over the years 2013-2020. Our analysis suggests that such outcomes are plausible, but are not the most likely outcome. The price of allowances in 2013 reflects the full distribution of potential supply/demand outcomes that could occur over the life of the program. If demand for allowances turned out to be higher than expected over the subsequent years (owing most likely to stronger than expected economic growth in the state) or the supply of abatement/offsets were lower than expected (owing to smaller effects of complementary policies than anticipated, smaller offset supply than anticipated, or other factors) then we would expect that the market price would gradually increase over these years to reflect the increased probability that a shortage of allowances could occur by the end of the program.

The potential for there being a range of outcomes in which the supply of abatement/offsets is very price inelastic (i.e., a steep supply curve) also raises concerns that small changes in the demand for allowances might have substantial effects on the allowance price. Such a situation is at least a warning that there might be the potential for non-competitive activities by some market participants that could artificially inflate or depress the price. In ongoing work, we are examining these possibilities in more detail.

Figure 1 Supply of Abatement

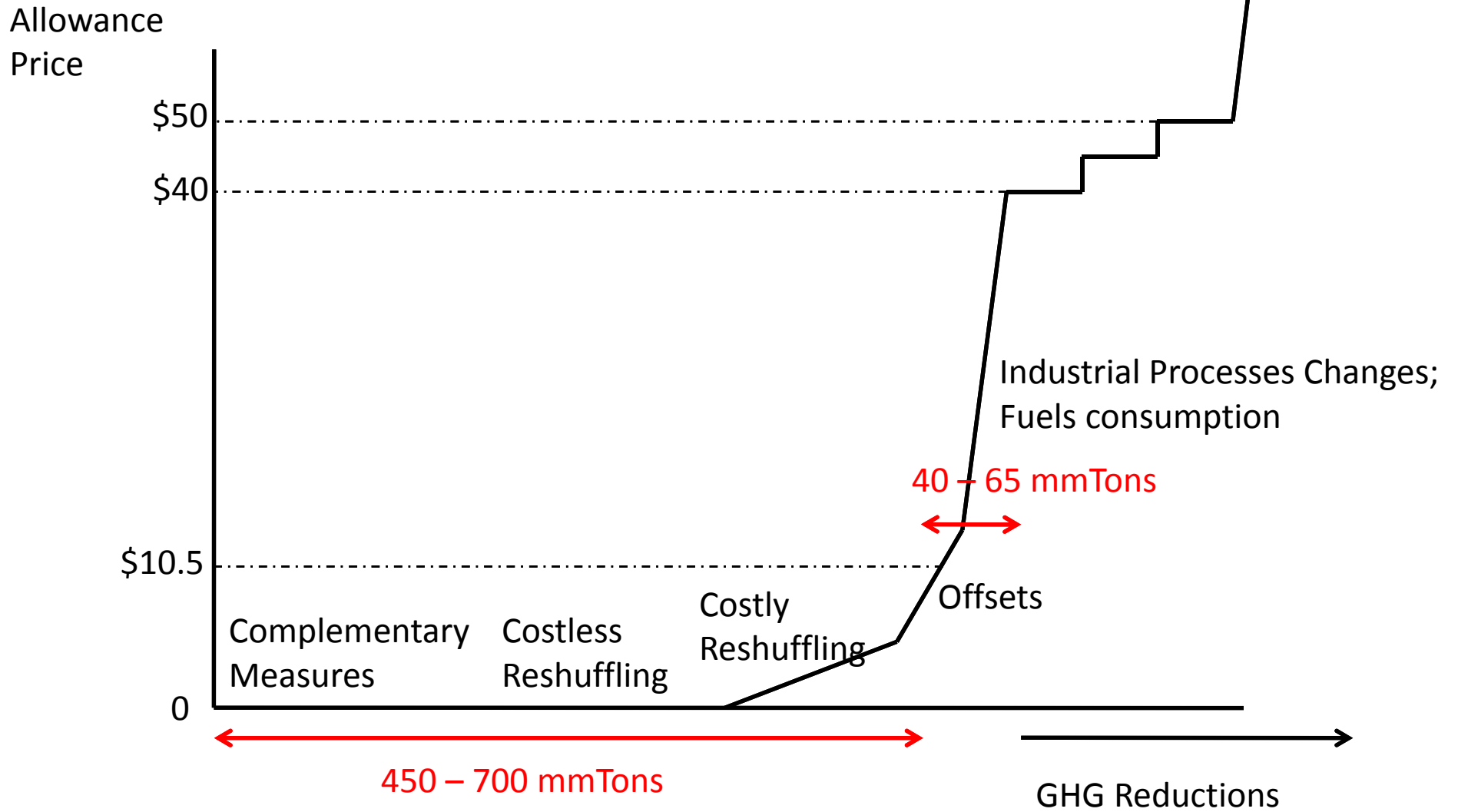


Figure 2
Hypothetical Distribution of Abatement Demand (BAU minus Allowances Outside Containment Reserve) vs Abatement Supply

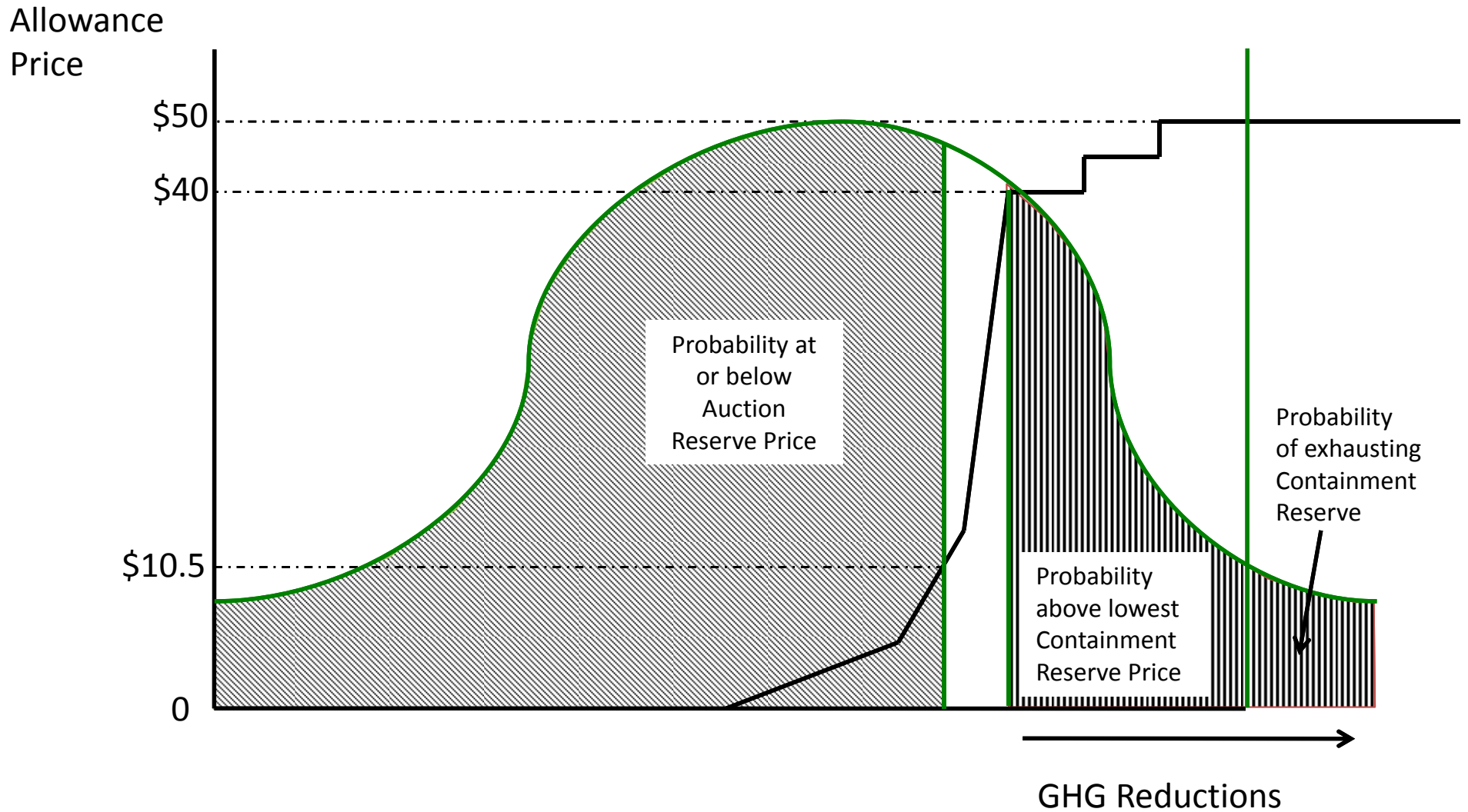


Figure 3
Possible Density Functions of Allowance Price

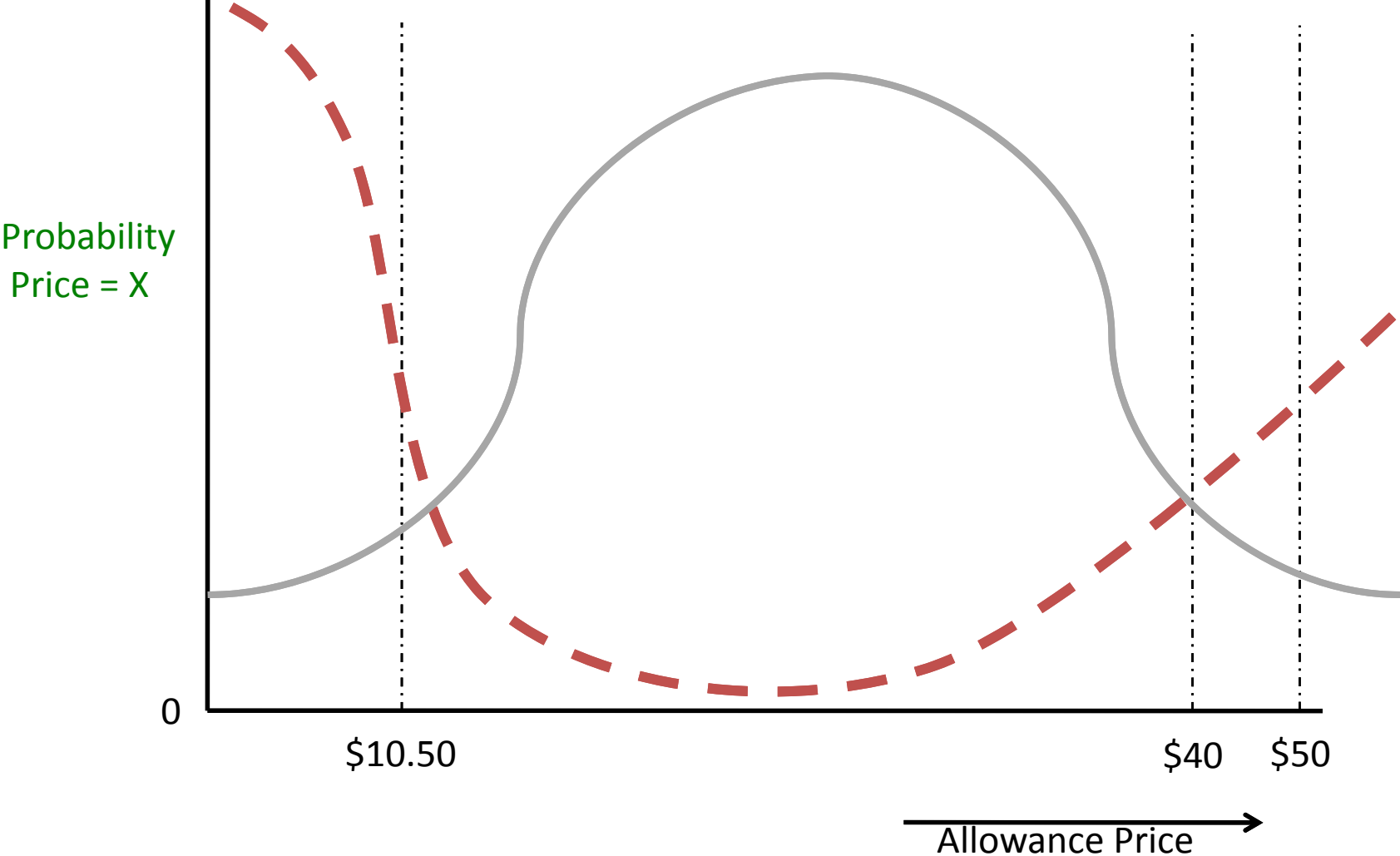


Figure 4a

Estimated Business-As-Usual Emissions

(with GHG Ratios to Other Factors Bounded Above at Median Levels)

VECM(1) Cumulative CO2 Forecast (kernel density)
(conditional on GDP 2011 & 2012, intensities capped at sample median)
(model 2)

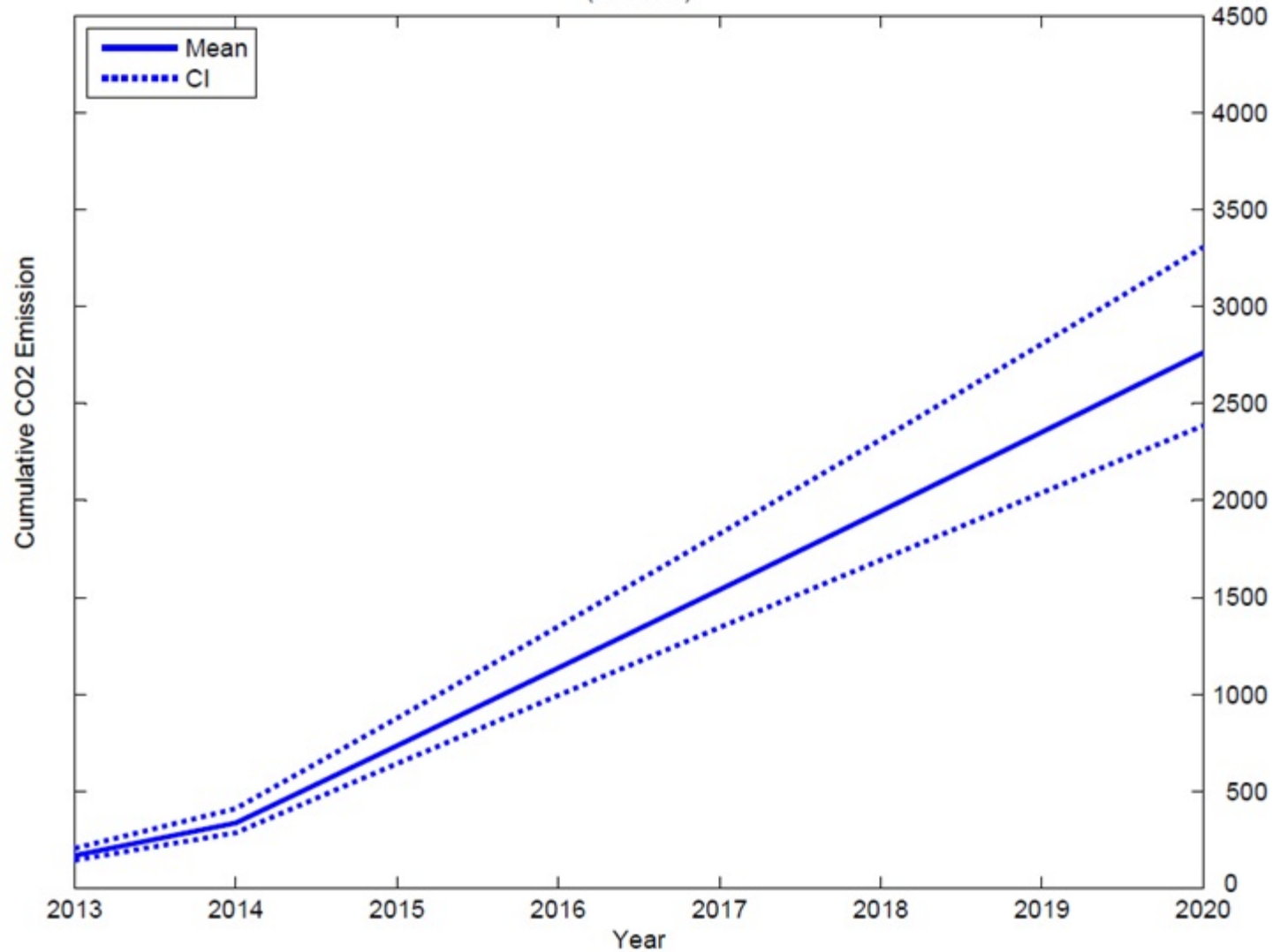


Figure 4b

Estimated Business-As-Usual Emissions

(GHG Ratios to Other Factors Bounded Above at 75th Percentile)

VECM(1) Cumulative CO₂ Forecast (kernel density)
(conditional on GDP 2011 & 2012, intensities capped at sample q3)
(model 2)

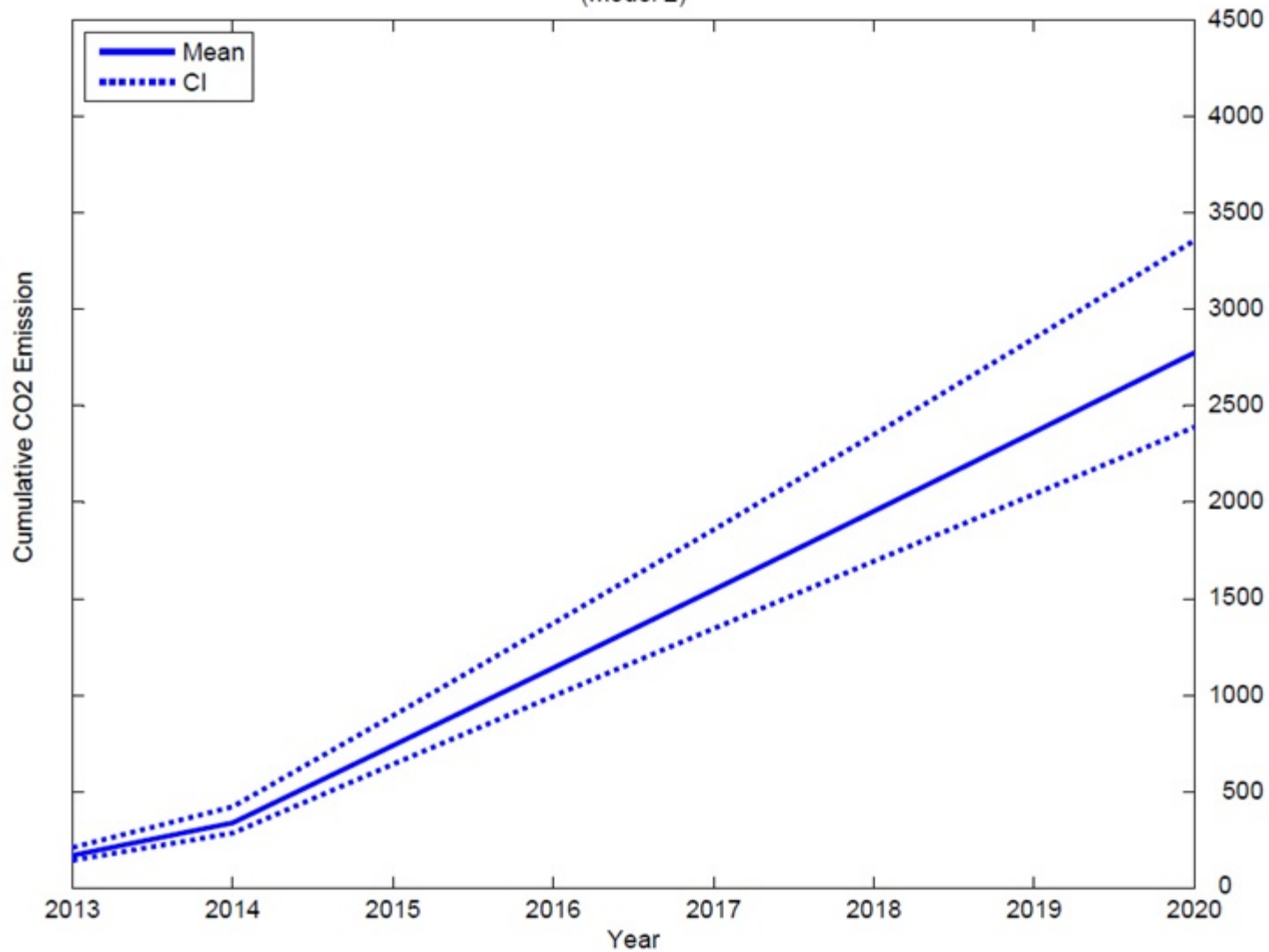


Figure 4c

Estimated Business-As-Usual Emissions

(GHG Ratios to Other Factors Bounded Above at Maximum)

VECM(1) Cumulative CO2 Forecast (kernel density)
(conditional on GDP 2011 & 2012, intensities capped at sample max)
(model 2)

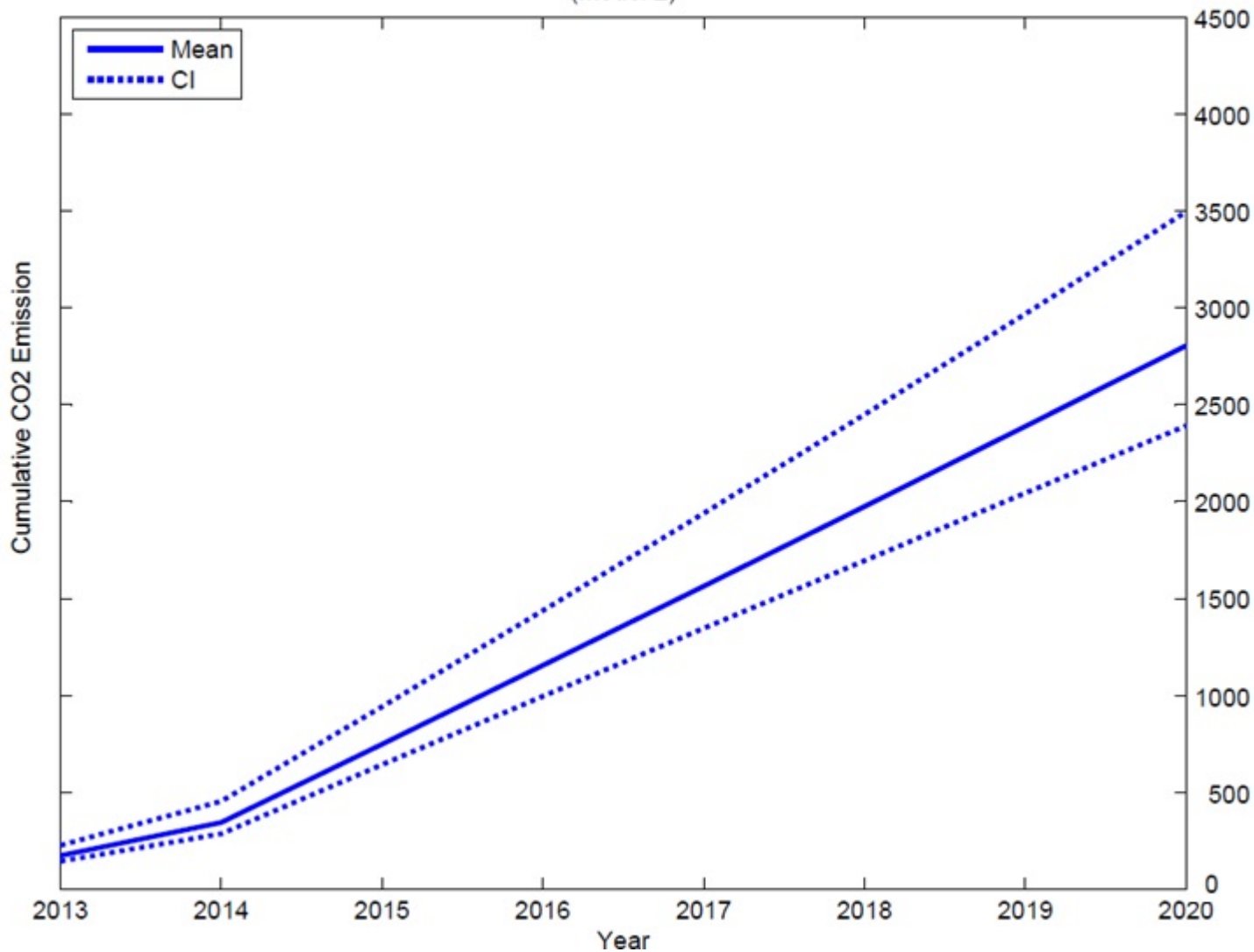
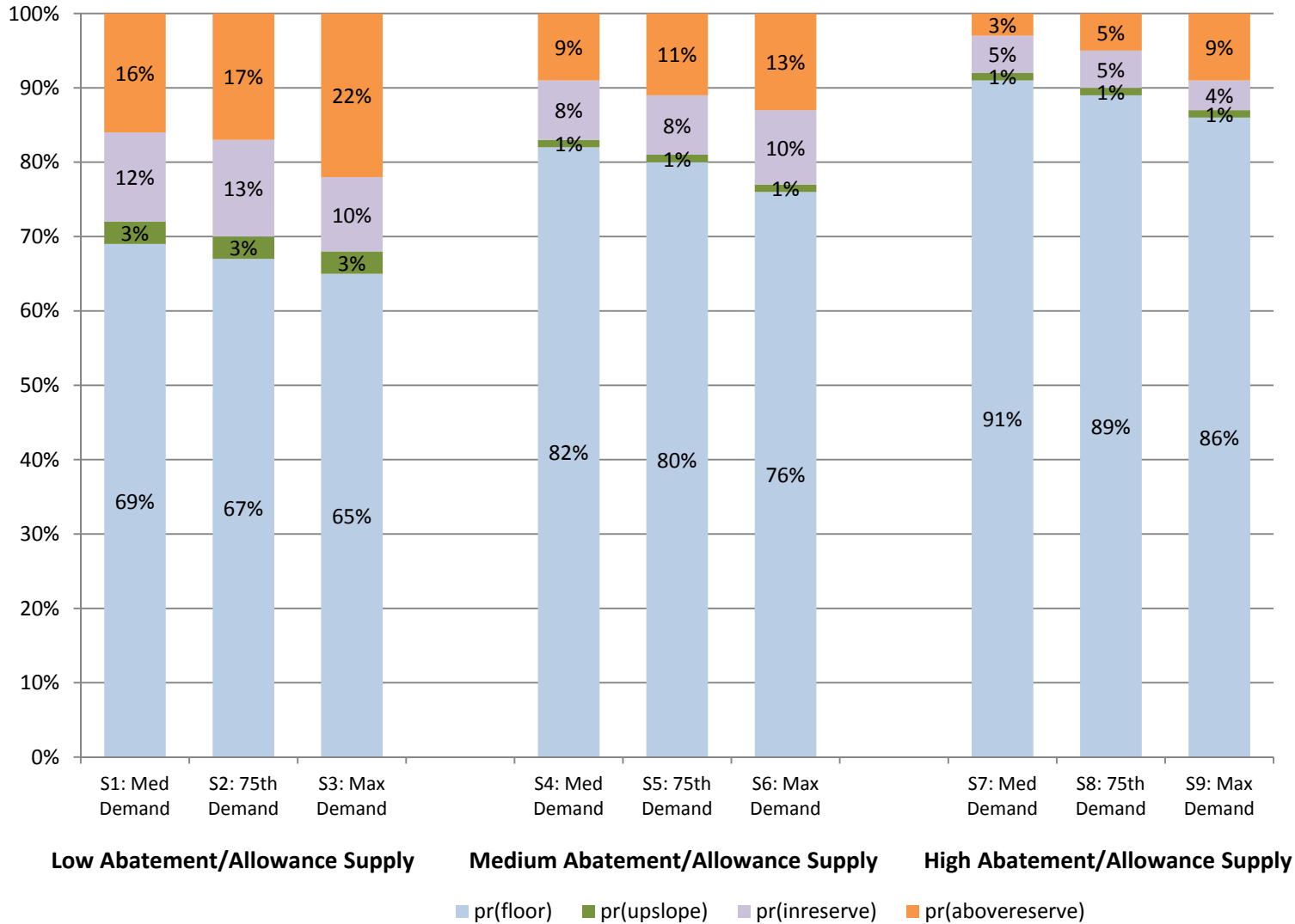


Figure 5

Allowance Price Probabilities by Scenario





EI @ Haas WP 236

**Downstream Regulation of CO₂ Emissions
in California's Electricity Sector**

James Bushnell, Yihsu Chen and Matthew Zaragoza-Watkins

January 2013

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Downstream Regulation of CO2 Emissions in California's Electricity Sector

James Bushnell, Yihsu Chen, and Matthew Zaragoza-Watkins.*

January, 2013

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 facility's 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 Fowle, 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 Fowle (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 $t \in \{0, \dots, T\}$, a perfectly competitive market outcome is obtained by solving the following welfare maximizing problem:

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

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 in-state 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:

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

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 Agency's 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 NONCEMS 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 :

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

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

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

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.

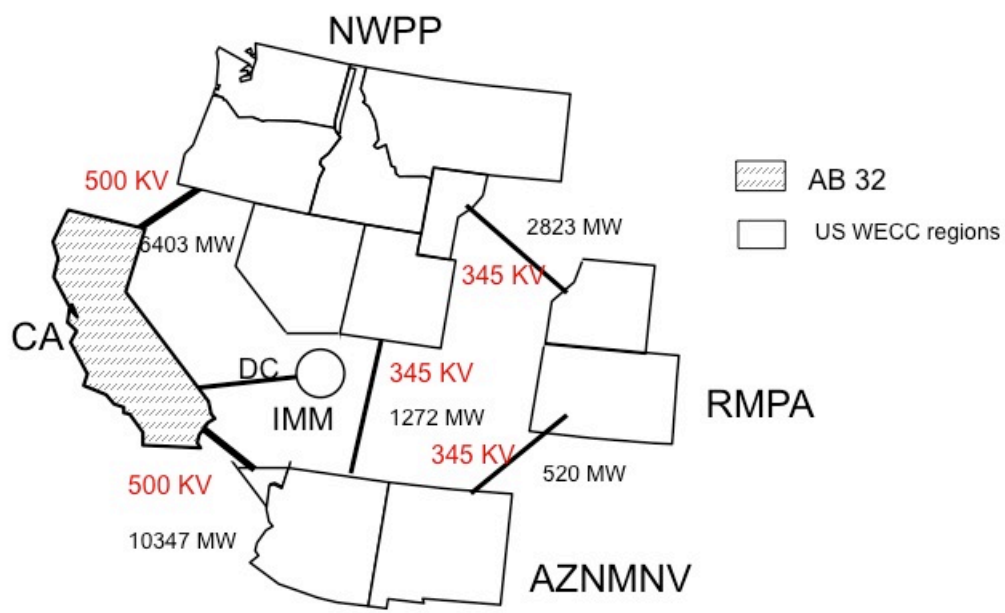


Figure 1: Western Regional Network and Cap-and-Trade Regions

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.

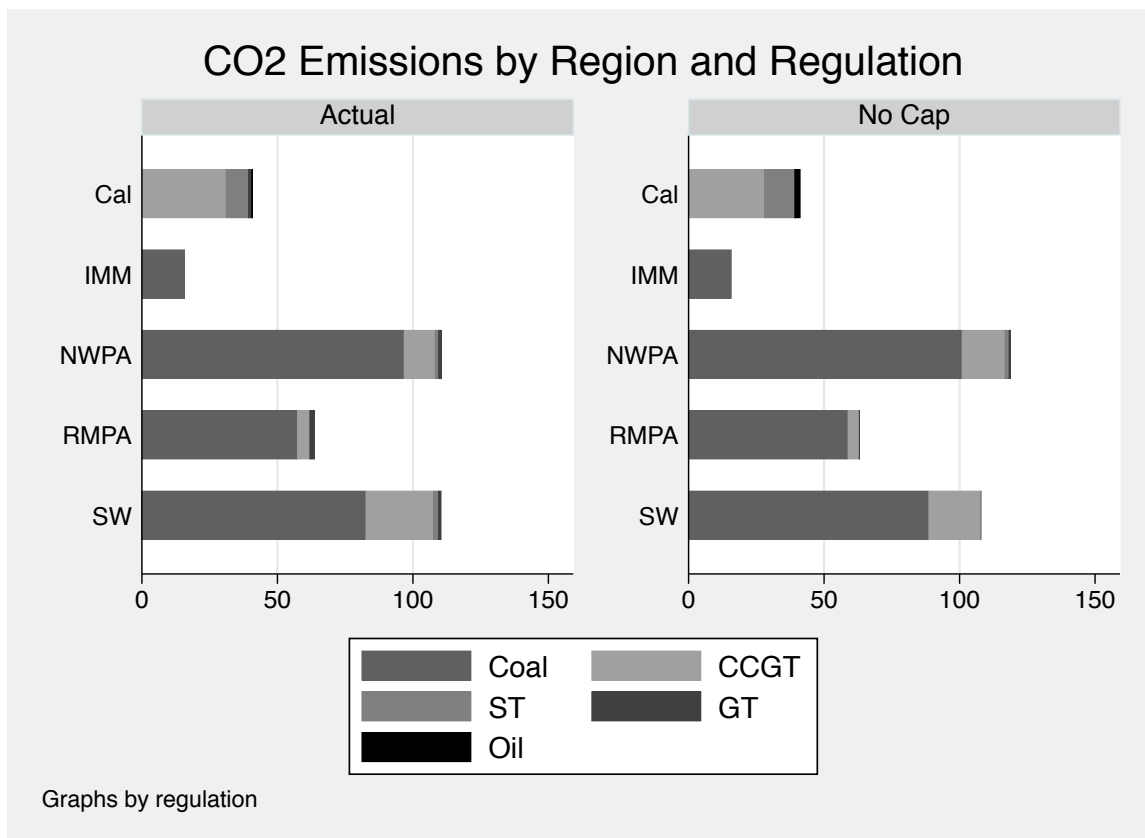


Figure 2: Actual Emissions and Simulation Results

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
Emissions mmTons	Cal	41.17	35.00	41.17	41.17	38.83
	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
Elec. Prices Avg. \$/MWh)	Cal	61.63	66.28	61.63	61.63	80.05
	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 facilities).
- 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
Emissions mmTons	Cal	41.17	30.88	36.64	35.84	39.40
	NW	118.78	123.48	120.24	120.60	116.56
	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
Elec. Prices Avg. \$/MWh)	Cal	61.63	69.35	86.2	82.91	83.08
	NW	68.32	80.2	73.43	74.15	91.34
	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.

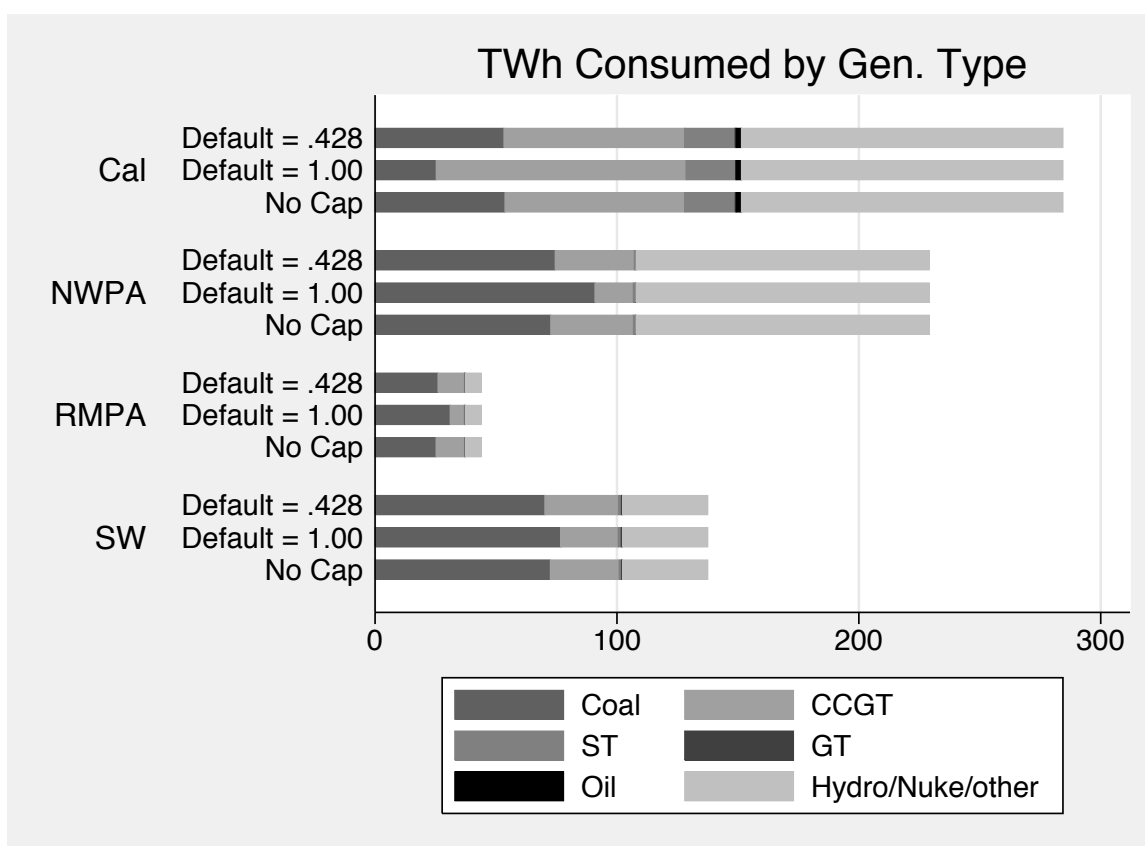


Figure 3: Consumption of Power with 15% reduction in CA Cap

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-

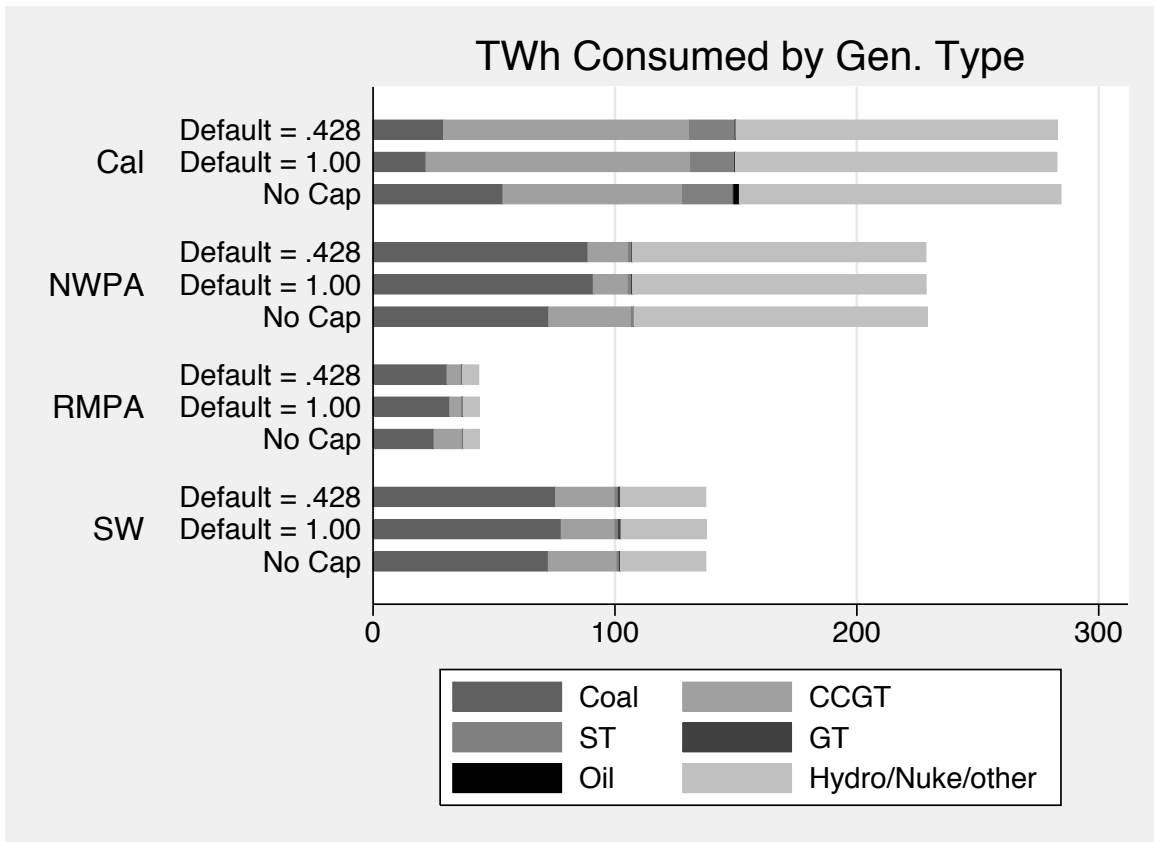


Figure 4: Consumption of Power with 25% reduction in CA Cap

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.

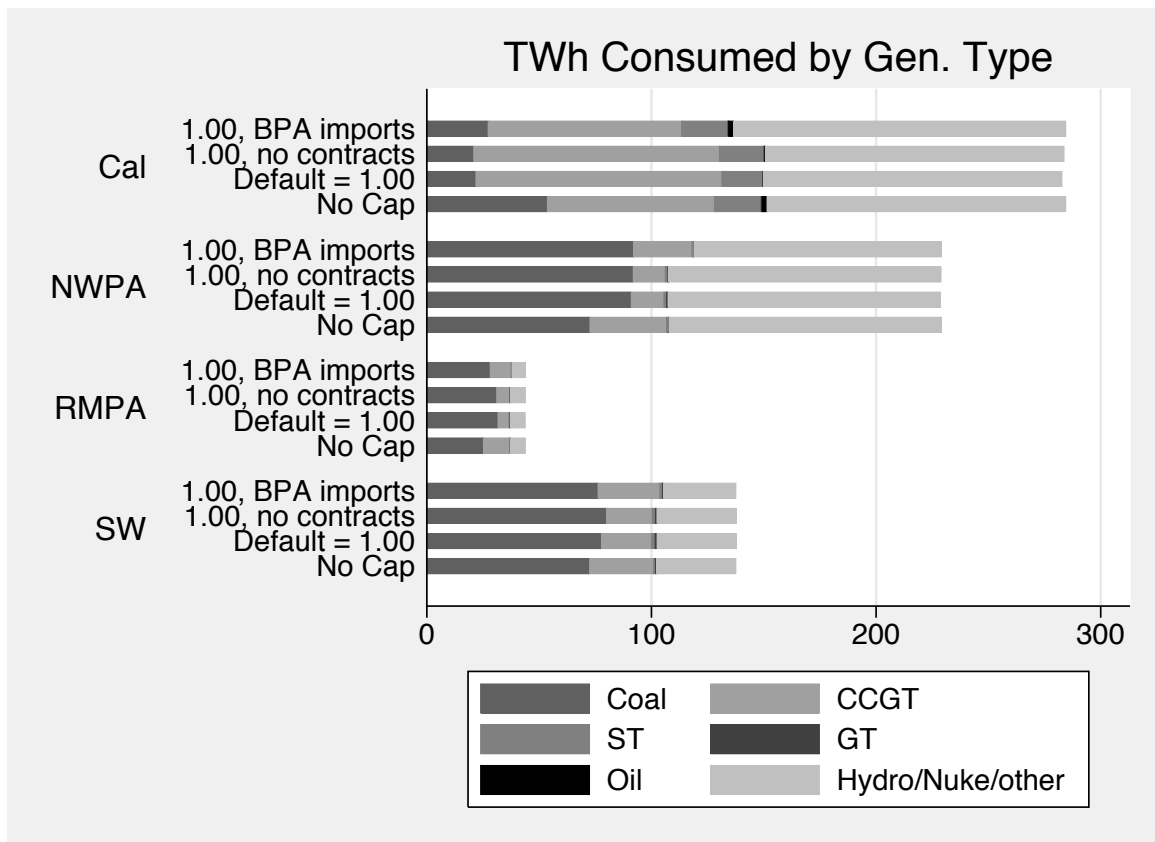


Figure 5: Enforcement of Anti-Shuffling Provisions

6 Conclusion

In this paper we analyze the impact of various forms of restrictions on greenhouse gases related to California's 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

¹Ironically, 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.

²WCI, 2008.

³In 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>.

⁴Although 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.

⁵When 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.

⁶It 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.

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

⁸The 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.