Covering New Gas-Fired Combined Cycle Plants under the Clean Power Plan

Implications for Economic Efficiency and Wholesale Electricity Markets

PREPARED FOR

NRDC

NATURAL RESOURCES DEFENSE COUNCIL

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NOVEMBER 2016

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This report was prepared for the Natural Resources Defense Council. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

We acknowledge Marc Chupka, Dean Murphy, and Ira Shavel of The Brattle Group for their conceptual contributions and peer review in developing this report.

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Executive Summary

If legal challenges to the Clean Power Plan (CPP) are resolved, state regulators will need to determine how to comply. One issue that states adopting mass-based compliance plans will need to address is whether to include new gas-fired combined-cycle (CC) plants under the mass-based cap on CO_2 emissions. As written, the CPP does not automatically cover CCs that began construction after January 8, 2014 because the rule was developed under Section 111(d) of the Clean Air Act (CAA), which regulates only existing plants.[1] New gas CCs are separately regulated under Section 111(b) of the CAA, which limits the CO_2 emissions rate of new gas CCs but does not place any limit on the total quantity of CO_2 emissions. Nevertheless, states have several options for covering or otherwise mitigating emissions from new gas CCs in their compliance plans.

This report is commissioned by the Natural Resources Defense Council (NDRC), a not-for-profit environmental organization. The NRDC is concerned that failing to cover new gas CCs would weaken the environmental outcomes anticipated under the CPP (32% carbon emissions reduction from 2005 levels by 2030), and introduce problematic economic effects in wholesale electricity markets. In this report, we examine the potential implications for competitive wholesale energy and capacity markets if new gas CCs are not covered under mass-based state implementation plans (SIPs).[2]

A mass-based emissions cap covering the CO_2 emissions from all existing and new fossil plants would require all covered generators to surrender one CO_2 allowance for each ton emitted. All fossil plants would then face the same marginal incentive to avoid emitting CO_2. If instead only existing fossil plants were covered, the emissions from new plants could significantly increase even while emissions from existing plants decrease under increasingly stringent caps. Increasing output from new gas CCs would undermine the ability to achieve the expected emissions reductions.[3] The EPA has acknowledged this risk of emissions "leakage" to new gas CC plants and requires states to mitigate this risk through their SIPs. The EPA has presented three options for states to mitigate leakage to new gas CCs in its final rule and proposed Federal

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1 See CPP Final Rule 80 Federal Register 64661 at § 60.5845.

2 Our scope includes an examination of both: (a) energy markets that are used to incentivize the least-cost dispatch and operations, and (b) capacity markets that are used to incentivized the least-cost investments for meeting resource adequacy or reserve margin requirements.

3 The EPA's standard for expected emissions reductions is based on estimated quantity of reductions that would be achieved if the state adopted a subcategory-specific emissions rate standard. The subcategory rate standards use a best system of emissions reductions (BSER) approach to determine the maximum allowable lbs/MWh CO_2 emissions rates for existing fossil steam (primarily coal, but also gas and oil-fired steam plants) and existing gas CC plants. For additional discussion of rate-based standards, see Chupka, *et al.* (2016).

Implementation Plan (FIP): (1) incorporating new gas CCs under a mass-based emissions cap, along with adding a "new source complement" that increases the state emissions budget in recognition of the broader scope of plants covered; (2) using an output-based allocation of CO_2 allowances to existing gas CCs and new renewables to partially offset the economic incentives that favor non-covered new gas CCs; or (3) developing an alternative proposal for EPA approval.[4]

Prior studies have found that covering new gas CCs under the emissions cap is an effective means of preventing leakage to new gas CC plants, but that the EPA's alternative set-aside proposal would not be effective. For example, MJ Bradley and Associates (MJB&A) found that covering new CCs would achieve 18–20% CO_2 emissions reductions compared to a business-as-usual case, while only 12–14% emissions reductions would be achieved if new CCs were not covered. Further, they found that the "EPA's proposed output-based allocation to certain existing [gas-fired CCs] and a 5% set-aside of allowances for renewables had a negligible impact on projected emissions" compared to a scenario where leakage to new CCs was left totally unmitigated.[5] Similarly, Resources for the Future (RFF) found that EPA's set-aside proposal is "insufficient to meaningfully reduce leakage" and that no amount of output-based allocation would completely prevent leakage under the conditions studied.[6] Our own analysis leads us to the same conclusion that the EPA's proposed set-aside approach would only partly mitigate leakage to new CCs because they would continue to emit CO_2 at no cost. The set-aside is not large enough to provide equivalent incentives to existing gas CCs or new renewables, and the set-asides do nothing to help equalize incentives for other types of non-emitting resources.

Some states may be attracted to the option of excluding new gas CCs from the mass-based emissions cap because of the relatively small quantity of additional allowances made available under the new source complement. The new source complement adds 1–10% (or 2% on average nationwide), to the states' emissions budgets even though the fraction of the fleet represented by new gas CCs will be larger than the new source complement in some places. For example, in the Electric Reliability Council of Texas (ERCOT) and PJM, gas CCs classified as "new" under the CPP already make up 5% and 12% of peak load respectively.[7] These new gas CCs are likely to

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4 See 80 Federal Register 64661 at 64887, and 80 Federal Register 64966 at 65021.

5 Specifically, this refers to the difference between two model runs that did not cover new CCs that were identical in every way except that one included the EPA's output-based set-asides (model run MB07) and one did not mitigate leakage (model run MB06). The runs produced the same CO_2 emissions to the third decimal place reported in the study. See M.J. Bradley & Associates (2016), pp. 12 and 19.

6 Even if allowances were 100% allocated based on an updating output-based method, leakage mitigation is limited to 1%–64%. Resources for the Future (2016), pp. 7 and 34.

7 This considers new gas CCs that are online, under construction, or cleared in the capacity market, but does not consider proposed plants. Reported as a percentage of 2016 peak load, 70.6 GW in ERCOT and 152.1 GW in PJM. Data procured from ABB, Inc., Velocity Suite (2016), PJM (2016b) and ISO New England (2016).

emit more CO_2 emissions than the new source complement before the first CPP compliance year even begins.[8] This proportion of non-covered gas CCs and the associated concerns will continue to grow over time as new resources are built. In this report, we use a combination of qualitative analysis and illustrative simulations to examine the effects that not covering these new CCs would have on wholesale electricity markets.

Organized wholesale electricity markets were founded with the goal of providing a non-discriminatory competitive marketplace for electricity purchases and sales. The structure is designed to efficiently use the lowest-cost resources to meet customers' electricity needs. The markets accommodate competition among a wide diversity of generation and demand resource types with different cost structures and technical capabilities, selecting the lowest-price resources to supply electricity. This structure reflects a basic economic principle that resource-neutral approaches will minimize system costs and ultimately customer costs. Even in regions where centrally managed markets do not yet exist, the same principle applies in that the lowest-cost resources are utilized first in order to minimize the cost of service.

A mass-based emissions cap that covers the CO_2 emissions of all existing and new fossil plants would be a technology-neutral approach to control CO_2 emissions.[9] Under such a system all covered generation plants would surrender one allowance for every ton of CO_2 emissions, and they would increase their energy offer prices by the cost of the CO_2 allowances that must be surrendered. Lower-emitting resources would incur lower emissions costs and therefore be relatively more cost-competitive compared to higher-emitting resources. Through the combination of uniform CO_2 emissions prices and energy prices, all suppliers would face the same marginal incentives to displace CO_2 emissions. If instead, some resources were to face a lower incremental cost for emitting CO_2, the system would create a bias toward dispatching and investing in those resources. That would increase the system costs, and eventually the customer costs, of achieving CO_2 emissions reductions.[10]

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8 For example in Texas, if the new CCs that are already built or under construction were to operate at a 75% capacity factor, then they would emit approximately 9 million tons per year of CO_2 emissions. This exceeds the 8.5 million tons per year new source complement available by 2030 under CPP (4% of the Texas state-wide CO_2 mass cap). See Environmental Protection Agency (2015d). Gas CCs in ERCOT have recently been operating at near a 50% capacity factor, but new gas CCs can be expected to operate significantly more including as baseload resources if they pay no CO_2 emissions costs and become more profitable to operate than existing fossil plants.

9 Our discussion is focused on CO_2 emissions rather than a fully inclusive treatment of CO_2e emissions that would cover other greenhouse gases (GHGs) because the CPP regulates CO_2 from the power sector but does not cover other greenhouse gases. However, the same general discussion about uniform treatment among resource types would apply to a regulation that more broadly covered other greenhouse gases and/or covered other sectors of the economy.

10 Throughout this paper, we use the term "system costs" to refer to the total investment, fuel, and variable costs needed to serve energy needs. We do not include the societal costs of the CO_2 emissions themselves as part of that definition.

In the wholesale electricity markets, excluding new gas CCs would introduce a discrepancy in the economics facing new and existing gas CCs that are identical in all respects other than their in-service dates. Under such a system, existing fossil generators would pay a uniform price for each ton of CO_2 emitted and would set energy prices at a higher level based on the cost of CO_2 allowances. New gas CCs would face no cost for emitting CO_2 and yet would earn greater revenues because of the higher energy prices. Thus, a new gas CC would generate more power, emit more CO_2, and earn a greater profit compared to an identical gas CC classified as "existing."

Such a wholesale electricity market would also produce inefficient investment incentives. Non-covered new gas CCs would be rewarded just as if they were non-emitting resources. The energy and capacity markets together would incorrectly signal that building and running new gas CCs would be one of the lowest-cost ways to reduce CO_2 emissions because the CO_2 emitted by the new plants would not be included under the capped emissions. By financially rewarding new gas CCs for CO_2 abatement that would not actually occur, the markets would induce an over-investment in new gas CCs. This would displace lower-cost CO_2 abatement opportunities such as investing in energy efficiency, building new renewable resources, and retaining existing nuclear or hydroelectric plants. The over-investment in new gas CCs would suppress capacity prices, which in turn can displace other potentially desirable capacity options such as investing in new demand response or retaining existing low or zero-emissions generators.

Ultimately, excluding new gas CCs from the emissions cap would result in CO_2 emissions exceeding the intended level and incur greater system costs per ton of CO_2 avoided. Further, the 2030 generation mix in the U.S. would include more CO_2-emitting gas CC resources and fewer clean resources such as energy efficiency, demand response, and non-emitting generation.

Those that invest in new gas CCs based on the inefficient price signals would face regulatory risks associated with the likelihood that future policies may ultimately impose emissions reductions on the relatively recent investments. The risk they would face is that future CO_2 policies would level the playing field for all emitting power generators. Such a future is likely as a correction if the "new CCs" today are built simply because of the differentiation between "existing" and "new" under today's policies. Placing regulation on recently built facilities would ultimately increase the system costs if today's "new" gas CCs (and the associated natural gas pipeline infrastructure) soon become underutilized assets and additional investments in low- and zero-emitting resources eventually need to be made in any case. These concerns are amplified in markets facing a large number of coal retirements over the coming years, where the long-term emissions and system costs trajectories could be very different if the retiring plants are replaced by CO_2-emitting resources rather than non-emitting resources.

Based on this analysis of the interactions in wholesale electricity markets, we find strong reasons for choosing to cover new gas CCs under the CPP. Covering new gas CCs under the new source complement would eliminate the discrepancy in treatment and introduce a uniform incentive to avoid CO_2 emissions. This level playing field approach is consistent with the technology-neutral principles that enable wholesale electricity markets to meet energy, capacity, and CO_2 reduction needs at lowest system costs.

I. Background and Motivation

The Natural Resources Defense Council (NRDC) has asked us to evaluate the wholesale electricity market implications of covering or not covering new gas combined-cycle (CC) plants under the Clean Power Plan (CPP) mass standard. In this report, we evaluate the potential impacts of not including new gas CCs on realized CO_2 emissions, market pricing, operations, investment decisions, and total system costs. Under the CPP, states have the option to prevent CO_2 emissions leakage to new gas CCs either by covering them under the new source complement or demonstrating that they have addressed the issue in another way. In this report, we identify a number of potential market distortions and inefficiencies that would materialize if new gas CCs do not face the same costs of CO_2 emissions as other existing fossil plants.

A. Clean Power Plan Overview

In August of 2015, the U.S. Environmental Protection Agency (EPA) finalized the CPP as the first nationwide CO_2 regulation for existing fossil generators. The EPA estimates that under the CPP, electricity sector emissions will decrease to 32% below 2005 levels by 2030. The EPA proposed a federal implementation plan (FIP) and accepted comments on that proposal. Once the FIP is finalized, state regulators will have the option to either accept the FIP or design their own state implementation plans (SIPs) for CPP compliance. In February 2016, the U.S. Supreme Court granted a stay that suspended implementation of the CPP, while the D.C. Circuit Court of Appeals reviews legal challenges.[11] Some states are proceeding with CPP compliance planning or stakeholder engagement processes despite the stay, while others have suspended their efforts to develop SIPs.[12]

States have a substantial amount of flexibility in how to comply with the CPP. One central decision is whether to enforce the CPP under: (1) a *rate-based standard* that imposes a maximum CO_2 emissions rate in lbs/MWh; or (2) a *mass-based standard* that imposes a state-wide cap on total tons of CO_2 emissions from covered plants.[13] This report focuses on the approaches used to meet the requirements of the CPP using a mass-based standard.

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11 See Stohr and Dlouhy (2016).

12 See E&E Publishing (2016).

13 Under rate-based standards, covered fossil plants must either physically reduce their CO_2 emissions or else reduce their effective emissions rate by surrendering emissions rate credits (ERCs) to demonstrate compliance. Each ERC reflects 1 MWh of zero-emissions energy. States have the option of selecting either a subcategory rate (that applies different rate standards to fossil steam and gas combined cycle plants, and is a trade-ready approach) or a state-average rate (that applies one rate across all covered units within one state, but is not a trade-ready approach). We do not discuss rate-based plans further

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The EPA has proposed that enforcement of the emissions cap under the mass-based standard will be ensured through tradable CO_2 emissions allowances. This is a similar approach to that used in the cap-and-trade programs adopted in nine Northeast and Mid-Atlantic states under the Regional Greenhouse Gas Initiatives (RGGI), in California under Assembly Bill 32 (AB 32), the European Emissions Trading System (EU ETS), and other international mechanisms.[14] Each allowance represents a permit to emit one ton of CO_2, with the number of allowances set to equal to the tons of emissions allowed under the cap. Emissions allowances may be initially distributed by auction, to customer representatives, or to generators.[15] Once allocated, allowances can be purchased or sold bilaterally or through an allowance exchange. Each covered fossil generator must demonstrate compliance by surrendering one allowance for every ton of CO_2 it has emitted during a given compliance period.

This cap-and-trade mechanism creates market incentives to pursue the lowest-cost opportunities to reduce CO_2 emissions. The flexibility to trade allows the most cost-effective fossil generators to procure the available CO_2 allowances, achieving the required CO_2 reductions at lowest cost. The price of CO_2 allowances is determined by their relative scarcity and the marginal cost of avoiding emissions from covered sources.

B. The Treatment of New Gas Combined Cycle Plants under the CPP

New fossil plants that began construction after January 8, 2014 are not automatically covered under the CPP because it was developed under Section 111(d) of the Clean Air Act (CAA), which regulates only existing generating facilities.[16] New gas CCs are separately regulated under CAA Section 111(b), which limits the maximum CO_2 emissions rate of a new gas CC but does not place any limit on the absolute quantity of CO_2 emissions.[17]

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here as this is outside the scope of this report. For additional discussion of rate-based approaches, see Chupka, *et al.* (2016).

14 See World Bank (2014).

15 For additional discussion of alternative approaches to distributing emissions allowances, see our forthcoming paper Chang, *et al.* (2016).

16 See EPA (2015e).

17 New gas CCs that commenced construction after January 8, 2014 are required to meet a CO_2 emissions rate of 1,030 lbs/MWh or lower under the 111(b) standard, see GHG Standards for New Units 80 Federal Register 64509 at § 60.5509. The standard for new plants is commensurate with the physical emissions rate of new gas CCs; the nation-wide average emissions rate is approximately 951 lbs/MWh for plants that are in operation and classified as new under the CPP, based on data from ABB (2016). By comparison, the CPP imposes a substantially lower rate of 771 lbs/MWh on existing gas CCs by the year 2030, see GHG Standards for New Units 80 Federal Register 64509 at § 60.5880. By 2030 the CPP rate will be below the physical emissions rate that can be achieved by gas CCs, and so must be achieved through the purchase and surrender of ERCs as discussed in footnote 13 above. Thus, the

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If left unmitigated, the consequence of the inconsistent treatment of new and existing plants could be a significant increase in the emissions from new plants even while emissions from existing plants are capped. The EPA has acknowledged this risk of emissions "leakage" to new gas CCs and requires states to mitigate the leakage risk in their SIPs.[18] The EPA defines leakage as total emissions from covered plants and new CCs exceeding the emissions that would be achieved if a state adopted a subcategory rate-based standard. This is because the subcategory rate standard is the primary expression of the best system of emissions reductions (BSER) that the EPA has the authority to regulate under CAA Section 111(d).

The EPA has offered three options for mitigating leakage risks as summarized in Table 1. These options include: (1) incorporating new gas CCs under a mass cap on CO_2 emissions and adding a new source complement to the state emissions budget; (2) partially offsetting the economic incentives for leakage to new gas CCs by awarding an output-based allocation (OBA) of CO_2 allowances to existing gas CCs that operate at a high capacity factor and awarding a set-aside of CO_2 allowances to new renewable energy; or (3) developing an alternative proposal for EPA approval.[19]

While the first option of covering new units under the new source complement is the simplest option for eliminating leakage, some states may be concerned about the relatively small size of the new source complement. States choosing to cover new gas CC plants would receive an additional allowance budget of only 1–10% (or 2% on average nationwide), compared to an alternative in which emissions from new gas CCs are entirely uncapped. The rest of this report explains that, even if some view the new source complement to be small, the alternative of not including the new gas CCs would create inefficiencies and wholesale electricity market distortions that should be avoided.

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difference in treatment between new and existing gas CCs will affect the economic efficiency of achieving CO_2 reductions in states adopting rate-based standards, but the nature of those effects are very different from the effects under mass-based plans and are outside the scope of this study.

18 See CPP Final Rule 80 FR 64661at 64822 and 64887.

19 The EPA has not provided detailed guidance on how to demonstrate that leakage will not occur under alternative proposed plans, except that the test will be the level of CO_2 emissions expected compared to that expected under the subcategory rate standard. See CPP Final Rule 80 FR 64661 at 64887–9, and CPP Proposed Rule 80 FR 64966 and 65021.

Table 1
Options for Mitigating Leakage to New Gas CCs Under the CPP

Option	Description
Cover New Gas CCs Under New Source Complement	• New gas CCs are covered under the CO_2 mass cap just like existing fossil plants • The state's CO_2 emissions cap is increased according to the new source complement • States can either adopt the EPA-estimated new source complement that would increase the emissions cap by 1–10% (2% on a nationwide average basis), or propose an alternative new source complement subject to EPA approval
Allowance Set-Asides as Developed by the EPA for the Proposed FIP	• Use CO_2 allowance allocations to counteract leakage; the proposed FIP includes three set-aside programs allocating 10–11% of nationwide allowances depending on compliance period • <u>Renewable Energy Set-Aside (All Compliance Periods)</u>: 5% of all states' allowance budgets will be set aside and awarded to new renewable energy as an incentive to build those resources and mitigate leakage to new gas CC plants[20] • <u>Clean Energy Incentive Program (1st Compliance Period)</u>: up to 1–10% (5% national average) of each state's allowance budget can be awarded to eligible renewable energy and low-income demand-side energy efficiency programs that avoid emissions in 2020–21; this total allowance budget includes a portion that states voluntarily allocate to these programs plus an equal quantity of matching allowances from the EPA[21] • <u>Output-Based Allocation (Starting 2nd Compliance Period)</u>: 1–27% (6% national average) of states' allowance budgets will be awarded to existing gas CCs under the updating output-based allocation to offset the incentive to shift emissions from existing to new gas CCs[22]
State-Proposed Alternative	• Demonstrate that the SIP will not induce leakage to new gas CCs either because of unique state characteristics or because the SIP will incorporate alternative mitigating measures • EPA states that "[t]his demonstration must be supported by credible analysis." It will determine "if the state has provided a sufficient demonstration that potential emission leakage has already been adequately addressed, or if additional action is required as part of the state plan"[23]

Sources and Notes:
"Leakage" here refers to the EPA's definition as CO_2 emissions exceeding the amount under a subcategory rate-based plan.
See 80 Federal Register 64509 at 64887–8, 80 Federal Register 64966 at 65021–2, 65022; EPA (2015b).

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20 Renewables must have an in-service date of January 1, 2013 or later to qualify. Allowances will be distributed in proportion to *projected* generation with *ex post* adjustments See Environmental Protection Agency (2015a) and CPP Proposed Rule 80 Federal Register 64966 at § 62.16245.

21 The Clean Energy Incentive Program is a voluntary program designed to incentive early action before 2022 in renewable energy and energy efficiency. Unlike the renewable energy and output-based allocation set-asides, states can choose to not participate in the Clean Energy Incentive Program by not allocating early action allowances.

22 Existing gas CCs are awarded CO_2 allocations in the following compliance period based on generation output in the prior compliance period. Existing gas CCs are awarded CO_2 allocations of 1,030 lbs/MWh produced for all MWh produced above the 50% capacity factor. If the total quantity of state-wide allowance allocations under output-based allocations would exceed the available set-aside, then individual generators are awarded their *pro rata* share. The size of the set-aside is sufficient to be fully funded if all existing gas CCs in the state have a capacity factor of 60% (*i.e.*, enough to cover a 10% capacity factor increase from 50% to 60%). See Environmental Protection Agency (2015b).

23 See 80 Federal Register 64890.

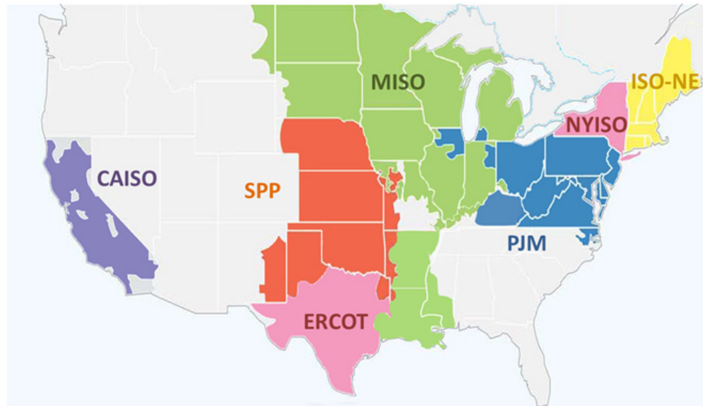
C. Motivation for Examining Impacts on Wholesale Electricity Markets

Organized wholesale electricity markets were founded on the principle of using non-discriminatory competition to ensure efficiency of plant dispatch and investment. The lowest-cost resources are selected to meet energy and capacity needs regardless of the underlying resource types, with prices set at marginal costs. These technology-neutral competitive markets are designed to minimize overall system costs in the short and long run, with the goal of minimizing long-run customer costs.

A mass cap that covers the CO_2 emissions of all existing and new fossil plants is compatible with operating competitive wholesale markets, as demonstrated in existing markets.[24] To maintain a level playing field across all resources, all fossil generators would be required to surrender one CO_2 allowance for each ton emitted and thus face the same marginal incentive to reduce emissions. This approach achieves the required CO_2 emissions reductions at lowest cost.

Not covering new gas CCs under a mass-based standard would introduce a deviation from the principle of resource neutrality and associated economic inefficiencies. These inefficiencies would manifest through distortions to the pricing, operations, and investment outcomes of the wholesale energy and capacity markets. In this report, we describe how these inefficiencies would affect wholesale electricity markets. The

Overview of Wholesale Electricity Markets



Sources and Notes:

Figure adapted from ISO/RTO Council (2016).
CAISO: California Independent System Operator
ERCOT: Electric Reliability Council of Texas
MISO: Midcontinent Independent System Operator
SPP: Southwest Power Pool
PJM: PJM Interconnection
NYISO: New York ISO
ISO-NE: ISO New England

Historically and in many parts of the U.S. today, electricity needs have been supplied by vertically integrated utilities that plan and build generation, transmission, and distribution to serve customers. These investor-owned utilities are awarded monopoly rights to sell power within a defined service territory. State public utility commissions (PUCs) have jurisdiction to oversee and approve the retail rates that utilities charge customers.

Over the past decades, wholesale electricity markets administered by Regional Transmission Organizations (RTOs) have been introduced in most of the country. Within a subset of these markets, including most of MISO, SPP, and California, regulated utilities remain vertically integrated and accordingly still determine what types of generation will be built. However, the RTO determines which generation resources will be scheduled to produce power, such that the lowest-cost resources are selected to serve customers across the region. Utilities exchange power within the wholesale energy market at prices calculated at the marginal production cost in each location, with efficiency gains ultimately translating to lower customer costs

In the rest of the markets, ERCOT, PJM, NYISO, and ISO-NE, the RTOs administer energy-only or capacity markets to incentivize new resource investments (although a subset of supply is still developed on a regulated basis. Under capacity markets, the RTO determines the quantity of capacity needed to reliably serve customers, and conducts an auction to procure the needed capacity at lowest cost. Merchant generation and demand resource developers sell their capacity resources into the market at the marginal cost of incremental supply.

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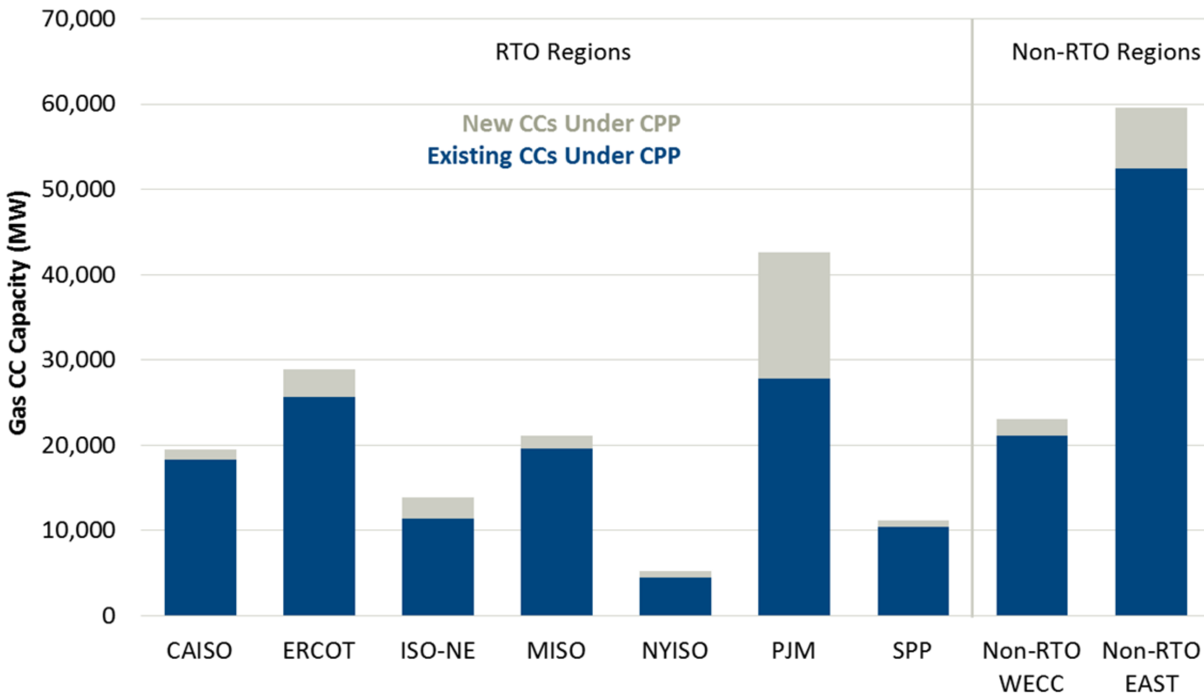
24 For example, as demonstrated in the cap and trade programs in Regional Greenhouse Gas Initiative and California markets, which both operate in RTO regions.

magnitude and nature of these inefficiencies would depend on what approach a particular state might take to mitigate CO_2 leakage, whether through the set-asides approach described in the FIP or through an alternative proposal.

The potential for leakage is amplified by the large number of investments in new gas CCs already completed or underway to replace retiring coal plants and meet load growth. As shown in Figure 1, there are over 33,000 MW of gas CCs in the U.S. already built, under construction, or cleared in forward capacity markets that are classified as "new" under the CPP.[25] The potential for market inefficiencies will continue to grow as these investments increase over the coming decades. The size of the concerns may be largest in PJM and ERCOT, where gas CCs classified as "new" under CPP already represent 12% and 5% of peak load respectively.[26]

Figure 1
Total Existing and New Gas CC Capacity by Region



Sources and Notes:

Reporting only resources that are under construction, online, or cleared in a forward capacity market (does not include proposed plants). We assume that resources that cleared in PJM and ISO-NE capacity markets and resources with online dates after May 1, 2016 will be classified as "new" (approximately consistent with January 8, 2014 construction start date).

Based on data from ABB Energy Velocity (2016), PJM (2016b), and ISO New England (2016).

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25 We include resources classified as new under the CPP that are online, have started construction (including those in site prep, under construction, or in testing), or have cleared the capacity markets in PJM or ISO New England. A "cleared" resource in a capacity market has a physical and financial obligation to come online prior to the delivery year, which may be up to three years forward. Based on data procured from ABB Inc. (2016), PJM (2016b), and ISO New England (2016).

26 Based on PJM and ERCOT 2016 summer peak load. See PJM (2016a) and ERCOT (2015).

II. Simulation Approach for Illustrating Market Impacts

We use a series of simplified simulations to provide an indicative comparison of policy scenarios with and without the new gas CCs covered under a CO_2 emissions mass cap.[27] We simulate the energy and capacity market outcomes in a hypothetical system in 2030 that is largely representative of the U.S. electric sector as a whole, but is not intended to characterize specific conditions in any one market or state.[28]

Figure 2 below summarizes our assumptions regarding the generation fleet and the primary costs for select generation technologies. We assume that the system starts with a modest deficit in capacity to illustrate the generation expansion that would be needed over approximately a decade to meet load growth and replace plant retirements.[29] We then simulate the lowest-cost combination of production and investment decisions that would minimize the costs for meeting energy and capacity requirements, without exceeding the applicable CO_2 emissions cap. As a simplification for the purposes of this study, we have not incorporated any endogenously-determined plant retirements or energy efficiency programs.

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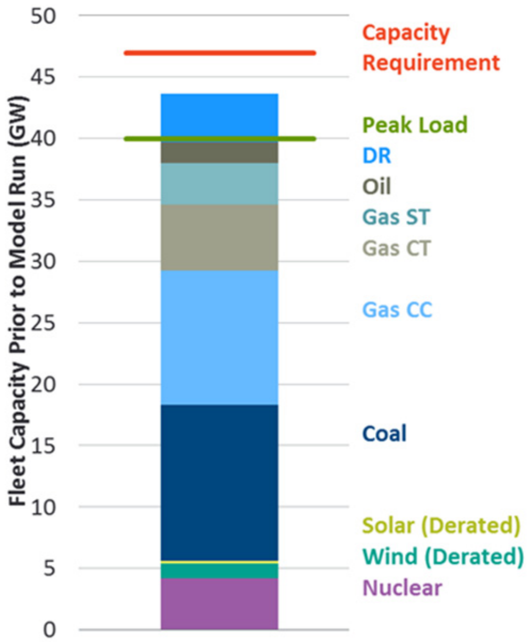
27 We use the Scenario Impact Model (SIM) developed by The Brattle Group to conduct these simulations; SIM is a model developed to analyze interactions across energy markets, capacity markets, and CO_2 policies.

28 The generation fleet and emissions reductions targets are largely in line with national average numbers, but not entirely. For example, as one simplification we have not included any hydroelectric resources, meaning that the results would not be as representative of the outcomes in hydro-rich systems.

29 The SIM tool is an expansion and dispatch model that minimizes the combined investment and production costs of meeting capacity and energy needs within the CO_2 mass cap. We implement a simplified one-year version of this model that examines only the year 2030 using annualized investment cost estimates, rather than optimizing over a multi-year timeframe. For our purposes we assume that the system (whether a single state or multiple states) is isolated from other electricity markets and is not linked with other CO_2 trading markets.

Figure 2
Fleet Makeup and Economic Assumptions in 2030 Simulations



Fuel Prices		
Gas Price	*($/MMBtu)*	$5.16
Coal Price	*($/MMBtu)*	$2.00
Fuel Plus Variable Costs		
Nuclear	*($/MWh)*	$5
Coal	*($/MWh)*	$36
Gas CC	*($/MWh)*	$43
Oil	*($/MWh)*	$80
Demand Response	*($/MWh)*	$400
Annualized Capital and Fixed Costs (ICAP)		
New Gas CC	*($/kW-year)*	$147
Wind	*($/kW-year)*	$190
Demand Response	*($/kW-year)*	$78

Sources and Notes:
Wind and solar are reported at 17% and 15% of nameplate respectively. All dollars reported in 2016$, inflation at 2% per year.
Wind annualized costs assume there is no production tax credit. Wind overnight costs are $1,611/kW in 2016$, based on NREL (2016). Charge rate and fixed cost assumptions from Newell, *et al.* (2013).
Gas CC levelized costs based on level-real cost of new entry estimates from Newell, *et al*. (2014b).

In Table 2 below, we describe the five scenarios that we analyze to evaluate the energy, capacity, and CO_2 market outcomes that would likely materialize under different assumptions about the treatment of the new gas CCs under the CPP. Scenario 1: Business as Usual is a baseline for comparison without any cap on CO_2 emissions. We then examine a series of alternative CPP cases that impose a cap on CO_2 emissions but allow covered generators to trade allowances to achieve least-cost compliance. Consistent with the rules of the CPP, we do not treat gas combustion turbines (CTs) as covered plants in any scenario.

Scenario 2: New Gas CCs Uncovered caps emissions from existing plants, but the cap does not apply to emissions from new gas CCs. Scenario 3: New Gas CCs Covered case achieves the same level of CO_2 reductions as Scenario 2: New Gas CCs Uncovered, but includes new gas CCs under the cap. Comparing Scenarios 2 and 3 allows us to compare the differences in operational and investment decisions needed to achieve a particular level of CO_2 reductions depending on whether new gas CCs are covered or not.

Scenario 4: New Source Complement assumes that 2% more CO_2 allowances would be added to the budget to accommodate new gas CCs, consistent with the average quantity of additional allowances that are available for SIPs covering new fossil plants under CPP. Finally, Scenario 5: Unanticipated Regulation is designed to illustrate a situation where the generation investments have already been made assuming that new gas CCs would not be covered (following the same build-out as the New Gas CCs Uncovered case), but at a later date, the new gas CCs are ultimately covered. Thus, the entire fleet must meet a more stringent mass cap than was anticipated when the generation investments (particularly in new gas CCs) were made.

Table 2
CO_2 Reduction Targets and Scenario Assumptions by Simulation Case

Scenario	CO_2 Mass Cap	Description
1. Business As Usual	n/a	• No CPP
2. New Gas CCs Uncovered	95 million tons from existing plants (Results in 111 million tons from existing + new plants)	• Covered : coal, gas steam turbines (STs), and existing gas CCs • Not Covered: New gas CCs
3. New Gas CCs Covered	111 million tons from existing + new plants	• Covered: existing fossil and new gas CCs • Achieve the same level of existing + new emissions reductions as the New Gas CCs Uncovered scenario to illustrate differences in how the reductions are achieved
4. New Source Complement	97 million tons from existing + new plants	• Increase mass cap by 2% new source complement • Covered: existing fossil and new gas CCs
5. Unanticipated Regulation	97 million tons from existing + new plants	• Using the resulting fleet from the New Gas CCs Uncovered scenario, impose the same emissions cap as in New Source Complement scenario • Covered: existing fossil and new gas CCs

Notes:
Consistent with the CPP, we do not treat gas CTs as covered in any scenario.

III. Interactions with Wholesale Energy Markets

Implementing a CO_2 emissions cap effectively imposes a cost on emissions and thereby creates incentives for electricity generators to find ways to reduce emissions. Those emissions costs will be reflected in the wholesale energy markets that are designed to dispatch the lowest-cost resources to meet consumers' electricity needs. When covered under the emissions cap, fossil generators will increase their offer prices commensurate with the cost of emitting CO_2. As the cap on emissions becomes tighter, the price of CO_2 allowances will become higher, and low-emitting and non-emitting resources will become more competitive. In this section, we describe how the choice to cover or not cover new gas CCs under the mass-based emissions cap would interact with wholesale energy markets through changes to CO_2 emissions levels, energy prices, and economic dispatch.

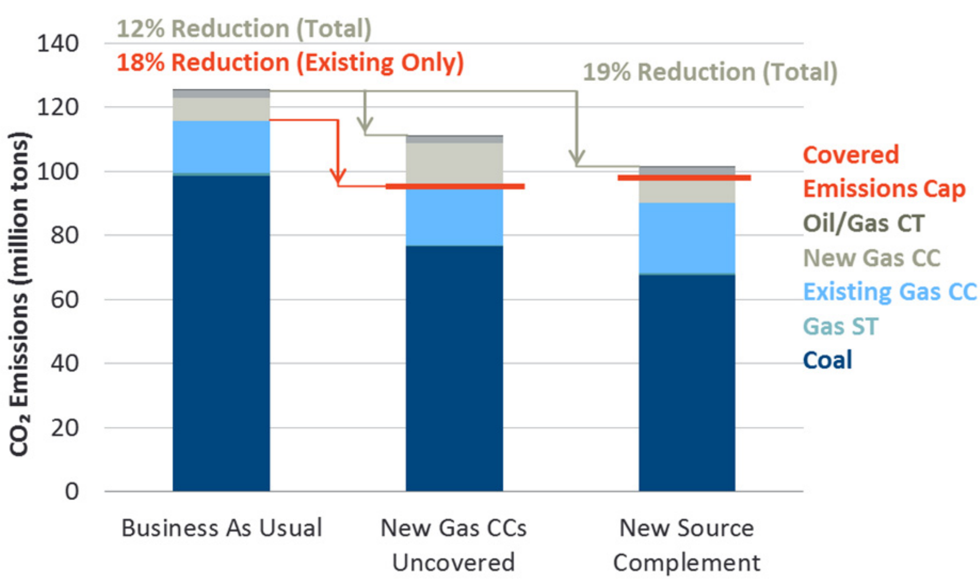
A. CO_2 Emissions Reductions and Leakage

If new gas CCs are not covered under the mass-based emissions cap, there is a significant potential to increase CO_2 emissions from those resources even if emissions from existing plants are restricted under increasingly stringent mass caps. Emissions increases from new gas CCs will partially offset the emissions reductions achieved from the existing fleet. Thus, the actual emissions reduction that will be achieved is inherently uncertain if some CO_2-emitting plants are not covered. This effect is illustrated in Figure 3 comparing the Business as Usual scenario to two scenarios with new gas CCs uncovered and covered. In the New Gas CCs Uncovered scenario, a CO_2 emissions cap is imposed that requires 18% emissions reductions from the existing fleet. However, only 12% emissions reductions are actually achieved in total when considering the entire fleet because there is a substantial increase in emissions from new non-covered gas CCs.

By comparison, the New Source Complement case (where a cap that covers new and existing resources is imposed) achieves a 19% reduction in total emissions from new plus existing resources. From an environmental perspective, the total emissions from all resources is the most relevant metric, even if the policy excludes some resources from the regulatory requirements.

Part of the discrepancy is driven by how the size of the new source complement was calculated. The 2% average size of the new source complement is based on an assumption that existing fossil plants and new non-emitting resources would provide a certain proportion of the electric system needs, while new gas CCs would meet only a relatively small proportion of total energy needs. If the new gas-fired CCs contribute to a greater fraction of the electric system needs than assumed in the EPA's calculation, this allows existing fossil plants to emit the same quantity of CO_2 that EPA estimated but while supplying a smaller fraction of the total system energy needs.

Figure 3
2030 CO_2 Emissions if New Gas CCs Are Covered or Uncovered



Notes:
New source complement sized at 2% of uncovered emissions target.

The EPA has recognized the concern that increases in emissions from non-covered new gas CCs could offset the emissions reductions achieved by the existing fleet. The EPA therefore requires that SIPs include provisions for mitigating CO_2 leakage to new gas CCs, either by: (1) covering new CCs in addition to existing fossil plants under the emissions cap, which is increased by the amount of the new source complement; (2) adopting the EPA's proposed allowance set-asides approach; or (3) proposing another measure.[30] We and others find that the EPA's set-aside proposal would have only a limited effect in offsetting the potential for leakage to new gas CCs. Although we do not simulate the effects of the proposed FIP in this study, we explain the reasons its effect would be limited in Section III.D below.

B. Energy Market Pricing and Dispatch Distortions

Categorically exempting new gas CCs from having to pay for CO_2 emissions when existing fossil generators are required to do so would provide the new gas CCs an undue competitive advantage in the marketplace. Since existing fossil generators would pay a price for each ton of CO_2 emitted, they would increase their offer prices in the energy market as illustrated in Figure 4. Without a price on CO_2, a coal plant may be the lowest-cost resource for meeting energy needs, but coal would become more expensive to dispatch if the costs of CO_2 allowances are added to their operating costs. Coal plants would then be dispatched less than gas CCs, thus reducing emissions.

The effect of a CO_2 allowance cap on gas CCs depends on whether they are covered under the cap. In the Scenario 2: New Gas CCs Uncovered, the existing gas CCs' offer prices would increase by approximately half as much as coal plant offer prices, because gas CCs emit approximately half the CO_2 emissions per MWh of generation. New gas CCs' offer prices would not increase however, because they would not be covered. New gas CCs therefore would become far more cost competitive than existing CC plants with identical operating characteristics. A new gas CC that is not covered by the cap earns a greater profit margin compared to the Business as Usual scenario because its energy prices have increased but its operating costs have stayed the same. Under Scenario 4: New Source Complement, new gas CCs' offer prices would have to incorporate allowance prices just like other existing fossil plants.

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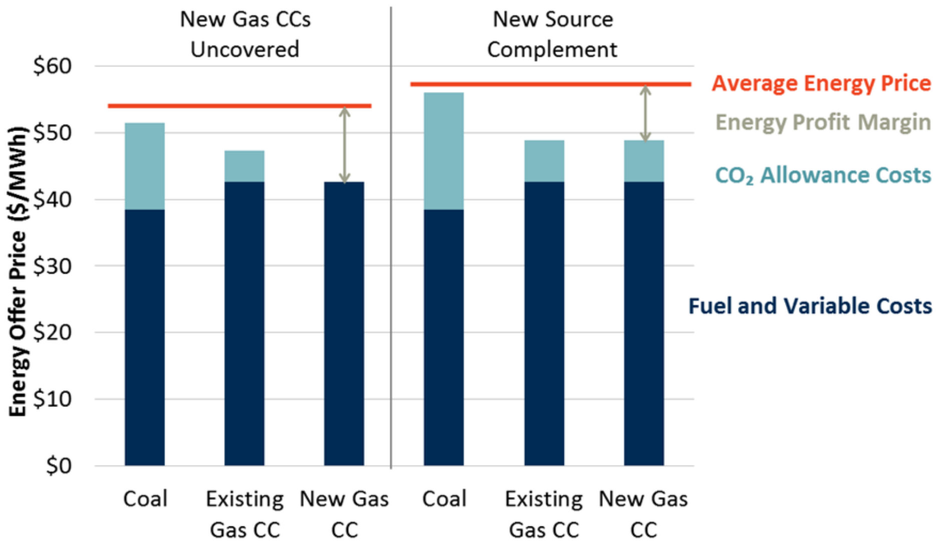
30 For the EPA's purposes, the term "leakage" is defined as any CO_2 emissions exceeding the CO_2 emissions that would be achieved under a subcategory rate-based plan. For our purposes, we define leakage more generically as shifting CO_2 emissions away from covered plants without reducing total CO_2 emissions. See CPP Final Rule 80 Federal Register 64661 at 64822. The set-asides approach is described in the proposed FIP, but is not yet finalized, see 80 Federal Register 64966 at 65018 and EPA (2015b).

Figure 4
Fossil Plant Energy Offer Prices if New Gas CCs Are Covered or Uncovered



Notes:
All dollars reported in 2016$.
Simulated CO_2 allowance prices are $11/ton and $15/ton in New Gas CCs Uncovered New Source Complement scenarios respectively.
Simulated average energy prices are higher than either coal or gas CCs' marginal costs because prices are sometimes set by higher-cost resources such as gas CTs.

Energy offer prices for new gas CCs under these different scenarios directly affect generation dispatch. Figure 5 below shows the simulated fuel switching under two scenarios compared to Scenario 1: Business as Usual, first without the new gas CCs covered under the emissions cap and second with new gas CCs covered under the new source complement. In both scenarios, dispatch would shift away from covered fossil plants (on the left) and toward lower-emitting and non-covered generation (on the right). If new plants are not covered, the primary means of reducing covered CO_2 emissions would be to fuel switch from coal to non-covered new gas CCs. Very little fuel switching would be induced toward existing gas CCs, and no incremental renewable generation would be induced.

> ***"The combination of increased renewable development and fuel-switching to existing gas CC plants would be more cost-effective approach to reducing CO_2 emissions than building and operating new gas CCs, but the market would only induce that least-cost result if all resources are competing on a level playing field under the emissions cap."***

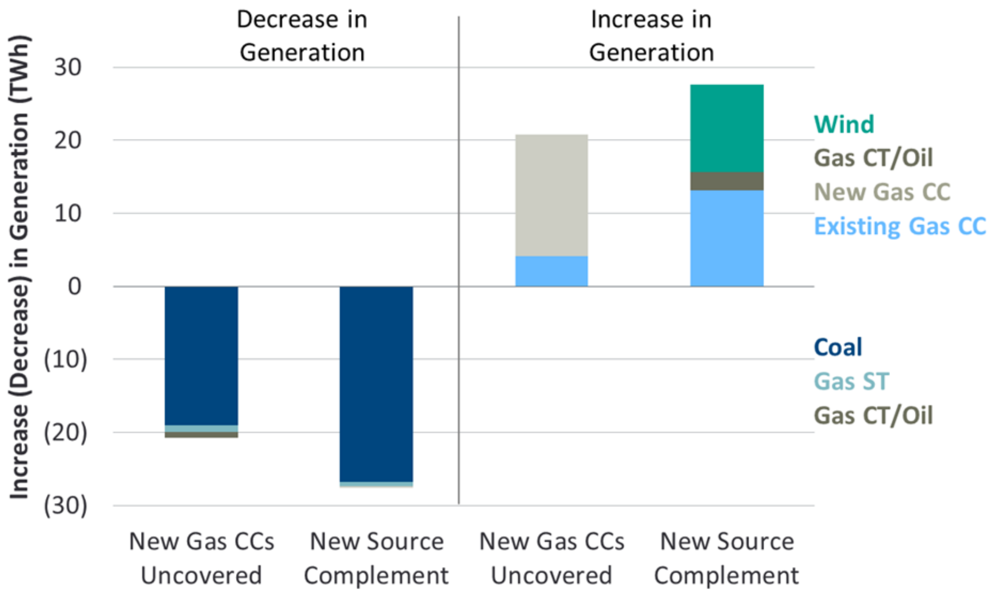
Covering new gas CCs under the new source complement would limit the increase in CO_2 emissions from new gas CCs, and require a greater reduction in coal generation to meet the tighter standard. More coal generation would be replaced by increased generation from new wind and existing gas CCs under Scenario 4: New Source Complement.[31] This shows that the

31 There is some fuel switching to existing gas CTs that are not covered even under Scenario 4: New Source Complement case. This shift in emissions to non-covered CTs is another example of what we

Continued on next page

combination of increased renewable development and fuel-switching to existing gas CC plants would be a more cost-effective approach to reducing CO_2 emissions than building and operating new gas CCs, but the market would only induce that least-cost result if all resources are competing on a level playing field under the emissions cap.

Figure 5
Change in Energy Generation Compared to Business as Usual



Notes:
The New Gas CCs Uncovered case shows more output from new gas CCs primarily because a large additional quantity of new gas CCs are built (once built, these new gas CCs operate at high capacity factors in all cases). The New Source Complement case induces substantial wind investment.

The discrepancy in economic incentives for new gas CCs is further illustrated in Figure 6, which shows the energy margins earned by gas CCs in the New Gas CCs Uncovered scenario and the New Source Complement scenario. The chart compares the profitability of existing and new gas CC plants that are identical in all respects other than their in-service dates. A new gas CC, if uncovered, would be far more profitable because it would run more frequently and earns a greater energy margin on every MWh produced compared to an existing gas CC.[32] By being

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define as leakage and is driven by the same effects that drive leakage to non-covered CCs. The magnitude of this potential leakage is smaller than the leakage to new gas CCs, but would become larger as CO_2 prices increase.

32 The energy margins reported exclude any value from freely allocated allowances, and implicitly assume that allowances are either: (a) purchased at the CO_2 allowance price, for example through an allowance auction, or (b) acquired through a free allocations process that does not depend on future behavior. The marginal production and investment incentives and energy margins earned by new and existing CCs will not be affected by the approach to allowance allocations in either case, although the cash value of any freely allocated allowances would accrue to plant owners. If allocations do depend

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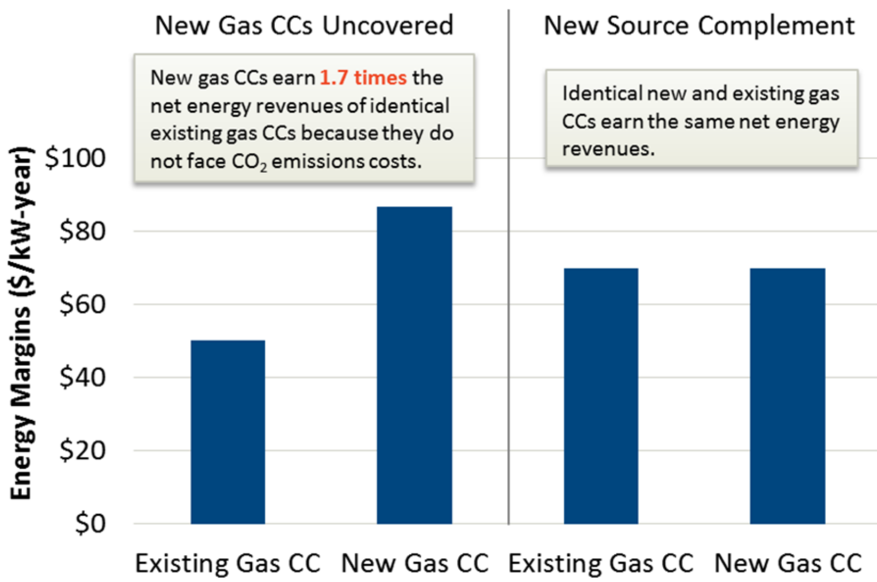
classified as "new" under the CPP, a gas CC plant would earn a 74% higher energy market operating margin compared to being classified as "existing." This higher energy margin would lead to over-investment in new gas CCs over time, as discussed further in Section IV below. By comparison, if both new and existing gas CCs are covered, identical plants would earn identical energy margins.

Figure 6
Energy Margins of Identical Gas CC Plants Classified as "Existing" or "New"



Notes:
All dollars reported in 2016$.
The discrepancy between new and existing gas CCs' energy margins in the New Gas CCs Uncovered scenario accounts for both a higher capacity factor of new gas CCs and the higher profit margin on each MWh produced. Capacity factors are 83% and 92% for existing and new gas CCs respectively.

C. Inaccurate Signaling of the Lowest-Cost CO_2 Abatement Opportunity

If CO_2-emitting resources are not covered under the mass-based emissions cap, the electricity markets would produce inaccurate signals regarding the most cost-effective means of reducing CO_2 emissions. This effect is illustrated in Figure 7 below for an hour when a coal plant is the marginal resource dispatched to meet energy needs. The left-hand chart shows that the coal generator would set the energy price based on fuel plus CO_2 allowance costs, and other lower-emitting resources earn an energy margin against that higher energy price.

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on future behavior as under the EPA's proposed output-based allocations approach, there are different economic incentives introduced as discussed further in Section III.D below. For additional discussion of the economic implications of allowance distribution alternatives, see Chang, *et al.* (2016).

The right-hand chart converts that energy margin into a payment per ton of CO_2 avoided if coal is displaced with gas CCs or with wind. Existing gas CCs that are covered under CPP and non-emitting wind resources are rewarded at an energy price that reflects the value of avoiding CO_2 emissions from a coal plant. Both types of resources earn incremental incentives through the energy market that translate to $11 per ton of CO_2 avoided, or the same as the market price for CO_2 allowances.[33]

"If new CCs are not covered, the wholesale energy market would reward non-covered plants as if they had zero emissions. The energy market would introduce the incorrect signal that switching to new gas CCs would achieve the same level of emissions reductions as switching to an entirely non-emitting resource such as wind."

By comparison, in the same situation, a new gas CC that is not covered by the CPP would be paid over 50% more per ton of CO_2 avoided, or much higher than the market price for CO_2 allowances.[34] This is because the wholesale energy market would reward non-covered plants as if they had zero emissions. The energy market would introduce the incorrect signal that switching to new gas CCs would achieve the same level of emissions reductions as switching to an entirely non-emitting resource such as wind.

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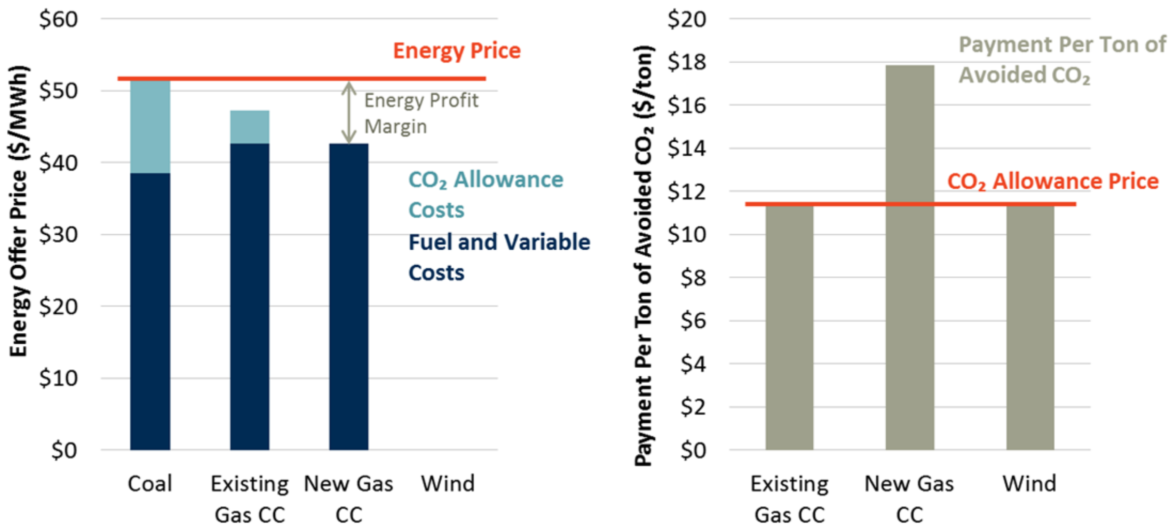
33 The energy margin in any one hour is driven by avoided fuel, variable, and CO_2 costs. Before accounting for CO_2 allowance costs, energy margins for the infra-marginal resource are based on the difference in fuel and variable costs compared to those of the marginal resource. For example, if a wind plant has zero variable costs, then its energy margin for producing one more MWh would be the avoided fuel and variable costs of the coal plant on the margin. When CO_2 prices are introduced, the energy margin is increased by the avoided CO_2 allowance costs. In this calculation, we subtract the portion of the energy margin attributable to avoided fuel and variable costs to estimate the portion of the energy margin attributable only to avoided CO_2 costs. We then divide by the tons of CO_2 avoided to get the payment per ton of CO_2 avoided.

34 This is true only in an hour when coal is the marginal price-setting resource. If an existing gas CC were on the margin, the payment to the new CC would be effectively infinite per ton avoided since there would be a $5/MWh payment to displace covered CO_2 even though no actual CO_2 reductions would occur.

Figure 7
Incentive to Displace CO_2 Emissions when a Coal Plant is the Marginal Energy Resource
New Gas CCs Uncovered Case



Sources and Notes:
Payments for avoided CO_2 is the energy profit margin net of avoided fuel costs, which is converted into $/ton using differences in emissions rates compared to the marginal resource (coal in this example). All dollars reported in 2016$.

D. Limited Mitigating Effect of the EPA's Set-Aside Proposal

The EPA's proposed FIP includes an option for using CO_2 allowance set-asides for existing gas CCs and clean energy resources to mitigate leakage to new gas CCs. As discussed in Section I.B, the EPA's set-aside proposal would award a portion of CO_2 allowances to existing gas CCs and new renewable resources based on their generation output in the previous compliance period. The value of these additional allowances awarded in the future would introduce greater incentives for renewables and existing gas CCs to increase generation in the current compliance period, thus partly offsetting the incentives for leakage to new gas CCs.

However, consistent with prior studies, we expect that the EPA's proposed approach would have limited effectiveness in offsetting leakage to new gas CCs and if implemented, the majority of the distortions in the wholesale market dispatch would remain as described throughout this report. For example, MJ Bradley and Associates (MJB&A) found that the "EPA's proposed output-based allocation to certain existing [gas-fired CCs] and a 5% set aside of allowances for renewables had a negligible impact on projected emissions" compared to a scenario where leakage to new CCs was left totally unmitigated.[35] Similarly, Resources for the Future found that the EPA's set-aside proposal is "insufficient to meaningfully reduce leakage."[36]

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35 Specifically, this refers to the difference between two model runs that did not cover new CCs that were identical in every way except that one included the EPA's output-based set-asides (model run MB07) and one did not mitigate leakage (model run MB06). The runs produced the same CO_2

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Our own analysis leads us to the same conclusion that the EPA's proposed set-aside approach would only partly mitigate leakage to new CCs because they would continue to emit CO_2 at no cost. The set-aside would not be large enough to provide equivalent incentives to existing gas CCs or new renewables, and the set-asides would do nothing to help equalize incentives for other types of non-emitting resources.

With respect to equalizing incentives between existing and new gas CCs, the potential effects of the EPA's output-based allowance allocation are illustrated in Figure 8. On the left side and discussed previously, an existing gas CC would need to pay the cost of CO_2 allowances to operate and so would offer a higher price into the energy market compared to new gas CCs that pay no allowance costs. The right-hand side of the chart illustrates the effects of the additional economic incentives introduced by the output-based allocations. If an existing gas CC could earn significant amounts of set-aside allowances in a future compliance period by increasing its generation in the current compliance period, this would create an additional incentive to increase its current generation. The existing gas CC would have an incentive to strategically bid into the market at a lower cost to increase its generation production. This can be translated into an offsetting effect on existing gas CC energy offer prices.

As shown in three examples on the right-hand side of Figure 8, the precise effect of the output-based allocation as proposed by the EPA would depend on the capacity factor at which the existing gas CC is operating and whether the output-based allocation is fully funded.[37] These examples illustrate that the output-based allocation can result in highly variable and uncertain outcomes that may not equalize incentives between new and existing gas CC plants:

- Existing Gas CC at Less than 50% Capacity Factor: An existing gas CC that operates at less than a 50% capacity factor in one period would earn no output-based allowances in the next compliance period.[38] For these plants, the output-based set-aside would have no effect in equalizing the incentives between existing and new gas CCs.
- Output-Based Allocations Fully Funded: An existing gas CC that operates at above 50% capacity factor would earn 1,030 lbs/MWh (or approximately 0.5 tons/MWh) in CO_2 allowances on each MWh of generation above 50%, as long as the total output-based

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emissions to the third decimal place reported in the study. Note that the definition of leakage referred to here is slightly different from the EPA's definition that refers to emissions exceeding that under a rate-based plan. See M.J. Bradley & Associates (2016), pp. 12 and 19.

36 Even if allowances were 100% allocated based on an updating output-based method, leakage mitigation is limited to 1%–64%. Resources for the Future (2016), pp. 7 and 34.

37 By "fully funded" we refer to the case where the full quantity of 1,030 lbs/MWh of CO_2 allowances can be awarded to existing gas CCs for all output above a 50% capacity factor. If the full quantity cannot be awarded we refer to the program as being "under-funded".

38 EPA (2015b).

allocation set-aside is fully funded.[39] In this case, the existing gas CC may have an incremental incentive to reduce its energy offer price down to the same level as new gas CCs. In reality, even under this situation, the existing and new gas CC offer prices may still differ due to: (a) the difference between the 1,030 lbs/MWh of CO_2 allowances awarded and the actual emissions rate of the existing gas CC in question, (b) the expectation that future CO_2 prices may be higher or lower than current CO_2 prices, and (c) the time value of money that would deflate the present value of allowances compared to the future date when the allowances would be awarded.

- Output-Based Allocations Under-Funded: An existing gas CC operating above a 50% capacity factor would earn a prorated share of allowances if the total quantity of output-based allocations would otherwise exceed the set-aside budget. The EPA designed the output-based allocation set-aside to be large enough to cover a 10% increase in existing CC capacity factors from 50% to 60% on a state-wide average basis.[40] The last example in Figure 8 depicts a scenario where the existing gas CCs operate at a 90% capacity factor, which would maximize the CO_2 abatement potential of fuel switching from coal to existing gas CCs. The set-aside budget sized to cover only a 10% (or 60% minus 50%) fleet-wide capacity factor would be divided over a 40% (or 90% minus 50%) fleet-wide capacity factor. The result is that the marginal incentives from the output-based allocations would be eroded to 25% of the intended size. Thus the output-based allocation set-aside would have only a portion of the intended effect of equalizing the incentives between existing and new gas CCs.

As a result, output-based allocations may have only a partial mitigating effect in correcting the discrepancy in the treatment of existing and new gas CCs. Even if they were to fully mitigate the emissions impact of not covering the new gas CCs, output-based allocations would still distort the market price signals received by non-emitting resources. If the existing gas CCs faced lower marginal emissions costs under output-based allocations and reduced their energy offer prices commensurately, then wholesale energy prices would be lower compared to an electricity market that reflects the full cost of CO_2 emissions. This lower energy price would reduce the incentives for retaining existing nuclear and hydro plants, and for attracting new non-emitting energy resources. In fact, if the output-based allocation were fully funded, it may result in reducing the offer prices of some existing gas CCs even below their fuel and variable costs, hence further suppressing energy prices and incentives for non-emitting resources.

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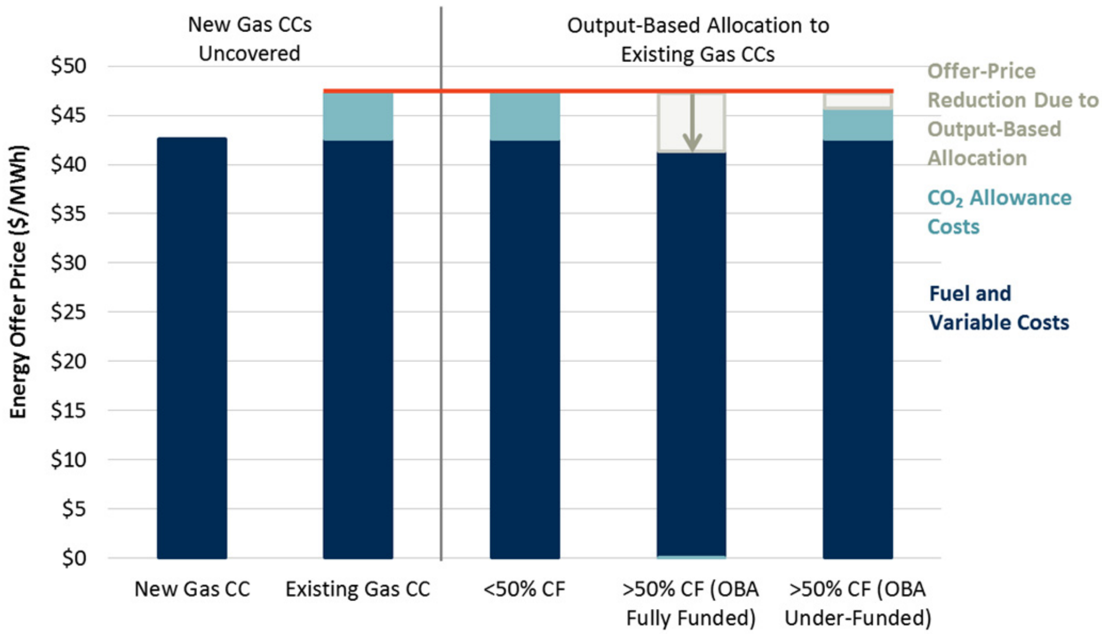
39 EPA (2015b).

40 In other words, the size of the fund was calculated to be large enough to increase the capacity factor of all existing CCs in that state from 50% to 60% capacity factor. EPA (2015b).

Figure 8
Energy Offer Prices for New and Existing Gas CCs
With and Without Output-Based Allocations, New Gas CCs Uncovered



Notes:

We assume identical emissions rates of 807 lbs/MWh for new and existing gas CCs and a CO_2 allowance price of $11/ton for both allowances in the present compliance period and the present value of future allocations. All dollars reported in 2016$.

When output-based allocations are fully funded, the offer-price reduction can exceed the emissions costs for existing gas CCs, which can reduce the offer price below fuel and variable O&M costs as shown.

For renewable energy resources, we expect the output-based allocations would have limited effectiveness. The EPA's proposed FIP includes a renewables set-aside of 5% of each state's allowance budget, with the allowances awarded on a *pro-rata* basis for eligible renewable plants with online dates after 2012.[41] This would provide an incentive to increase investments in renewable generation and therefore offset a portion of the emissions leakage to new gas CCs.

The magnitude of the incremental incentives for renewables would be highly variable by state. For instance, the number of allowances awarded per MWh of renewable energy produced would be lower in states with more renewable development and highest in states where renewable development has lagged. This may create a perverse incentive of providing minimal incentives to continue developing renewables where they are already proven as a relatively cost-effective CO_2 abatement option.

[41] The EPA has requested comment on whether there should be a cap on the number of allowances awarded to each plant, for example 1 ton per MWh of new renewable generation. CPP Proposed Rule 80 Federal Register 64966 at 65024.

Consider the example of Texas, which has both large renewable resource potential and a large potential for leakage to new gas CCs.[42] New renewables built or under construction are already sufficient to supply 9% of 2015 energy needs (19% of energy needs if considering new plus existing renewables).[43] Prior studies have estimated that renewables could economically supply up to 30% of energy needs by 2035.[44] At high levels of renewable deployment, the allowance set-aside designated to renewable resources would award approximately $1.5/MWh in additional incentives for new non-emitting renewables at an $11/ton CO_2 price. By comparison, existing gas CCs that do emit CO_2 would be awarded a much larger incentive of $6/MWh if output-based allocations were fully funded as shown in Figure 8 above.

Overall, the allowance set-aside proposal for both existing gas CCs and new renewables would not fully offset leakage incentives to new gas CCs. Further, existing non-emitting resources including existing nuclear, hydroelectric, and renewable plants would not be eligible to receive the set-aside allowances. The additional energy price suppression from output-based allocations could erode the economics of these plants. If baseload non-emitting resources retire due to eroded financial performance, they would be likely to be replaced by new gas CC plants running at baseload.

IV. Interactions with Wholesale Capacity Markets

Wholesale capacity markets would also be affected by the decision of whether or not to cover new gas CCs under the CO_2 emissions cap. Capacity markets are designed to ensure that a sufficient quantity of resources will be available to reliably meet demand during peak load conditions.[45] Generators and demand response providers offer their capacity into centralized

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42 ERCOT has approximately 3,500 MW of gas CCs classified as "new" under the CPP that are built or under construction, data from ABB Inc. (2016). This does not include any proposed plants and cogeneration.

43 In this calculation we define "new" resources consistent with the definition under CPP as those with online dates after 2012. Reported numbers are for the ERCOT system and do not include the non-ERCOT portion of Texas. To date, 8,900 MW of wind and 905 MW of solar are built or under construction since 2012, representing 48% of total installed wind and solar capacity. Assuming average capacity factors of 37% and 25% for wind and solar respectively, these plants can generate 31 TWh from new renewables and 66 TWh from new plus existing renewables, or 9% and 19% of ERCOT's energy served in 2015 (348 TWh). See Newell, *et al.* (2014a), Potomac Economics (2016), and ABB, Inc. (2016).

44 Shavel, *et al.* (2016).

45 This discussion is most relevant to states in the PJM region. While four of the U.S. RTOs have centralized capacity markets: ISO-NE, NYISO, PJM, and MISO, this discussion is less relevant to ISO-NE and NYISO because all of the states in these regions participate in RGGI, which already covers new gas CC plants. It is somewhat less relevant to MISO and SPP because the majority of states in those regions have vertically integrated utilities and accordingly, unlike PJM and ERCOT, there are relatively few "merchant" developers operating in MISO making investment decisions primarily based

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auctions at their net going-forward costs, and the system operator selects the lowest-cost resources to meet the reserve margin requirement.

A. Capacity Market Pricing Distortions

If CO_2 allowance costs are imposed on some but not all fossil plants, then categorically exempted resource types would become financially more attractive investment opportunities. Investors will want to build new power plants if they anticipate that the net revenues from the energy market plus the capacity payments will equal or exceed their annualized investment costs. The annualized investment costs for a generic plant in these markets is called the gross cost of new entry (CONE). Figure 9 compares energy plus capacity margins for existing and new gas CCs across three modeling scenarios.[46] In all of the three cases, new gas CCs would be needed to meet resource adequacy needs and so the energy plus capacity margins need to equal CONE for developers to invest in new plants. The net revenues between the energy and capacity markets complement each other such that a new plant will earn an adequate return on investment overall, although market fundamentals such as fuel and CO_2 prices determine the fraction of those revenues that are earned from the capacity market versus the energy market.

Under the New Gas CCs Uncovered case, the enhanced energy margins for new gas CCs reduce the capacity price needed before investments in new gas CCs become attractive. At these suppressed capacity prices, more new gas CCs would be built that displace otherwise lower-cost capacity resources such as demand response or retaining existing nuclear and hydro plants. Identical CCs that classified as "existing" would face a financial disadvantage compared to "new" CCs and would earn net revenues below their investment costs. If new gas CCs are covered under the New Source Complement, the discrepancy in revenues between new and existing plants would be restored to parity.

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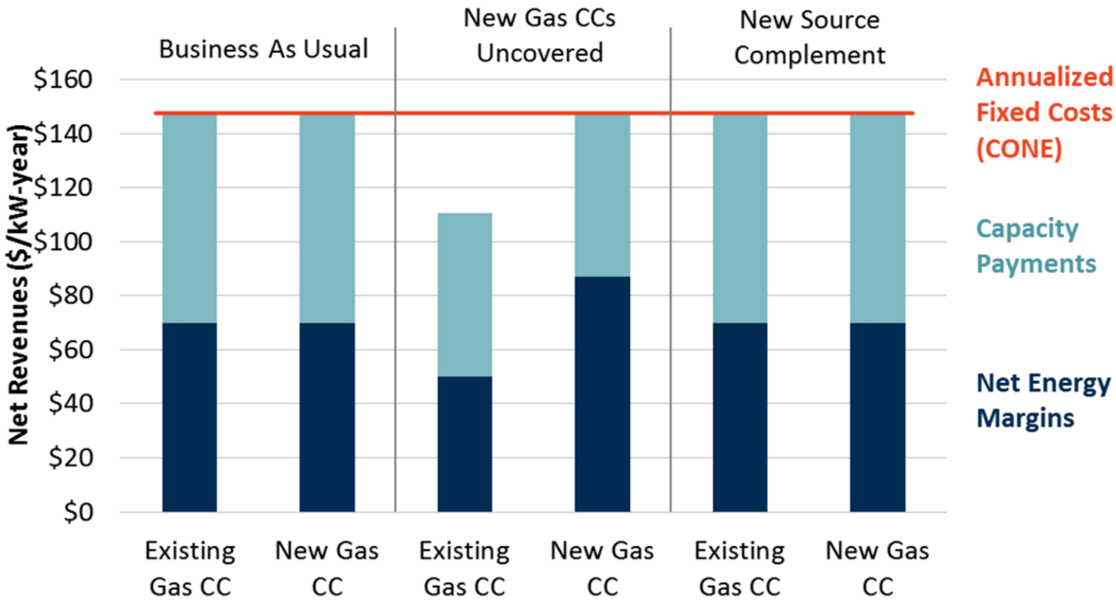
on anticipated wholesale market revenues. While we primarily discuss the merchant capacity market model here for narrative simplicity, the same economic drivers would influence the investment decisions of merchant investors in ERCOT's energy-only market and the investment decisions of utilities in SPP and MISO.

46 "Energy margins" refer to the net revenues or operating margin earned from the energy market; energy margins are equal to gross revenues minus variable costs including fuel, variable, and CO_2 allowance costs.

Figure 9
Net Energy Revenues and Capacity Payments to New and Existing Gas CCs



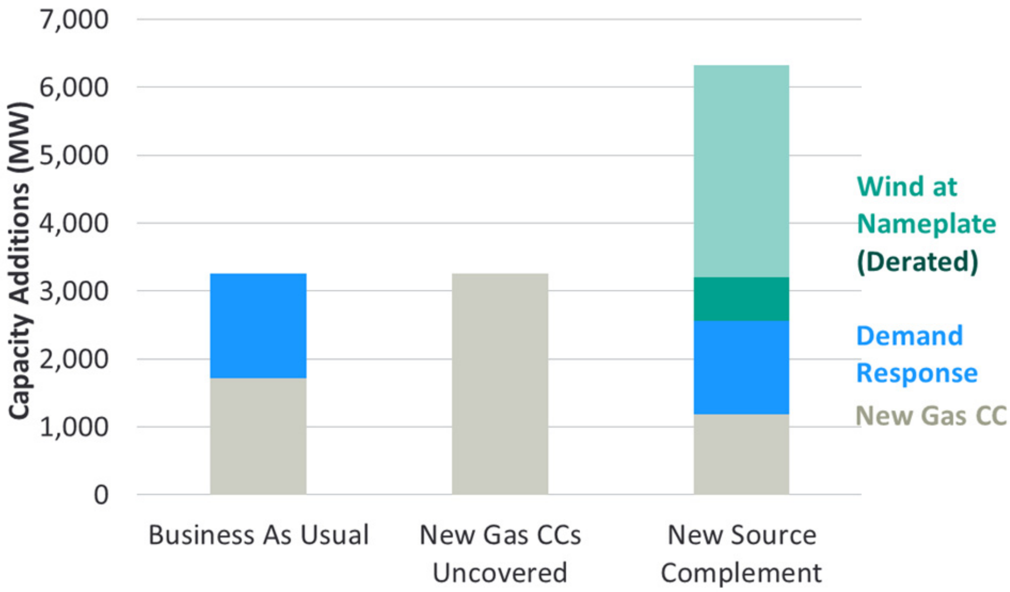
Sources and Notes:
Annualized fixed costs based on level-real gas CC CONE, see Newell, *et al.* (2014b).
All dollars reported in 2016$.

B. Resource Investments and Fleet Makeup

Over-investments in new gas CCs displace other resources that would otherwise be the lowest-cost options for meeting energy and capacity needs within the CO_2 emissions cap. Figure 10 illustrates these resource investment effects from our model simulations. The New Gas CCs Uncovered case would attract a large quantity of new gas CC investments, even displacing demand response as a capacity resource. Under that scenario, the market would introduce incentives to build and operate new gas CC plants in order to shift CO_2 emissions to these non-covered resources, just as if the emissions from the new gas CCs had no emissions at all. If different states in the same region made different decisions, with some states covering and others not covering new CCs, then the incentives to over-invest in new gas CCs would be uneven. In that case, new gas CCs would be built primarily in states that do not cover new plants.

If the CO_2 emissions from new plants are accounted for under the New Source Complement scenario, the competitive market would identify wind and demand response as being among the most cost-effective resource investments. The market would rely more heavily on fuel switching from coal to existing gas CCs and new wind to meet the required CO_2 reductions. New capacity needs would be met partly through wind (which contributes only modestly to capacity needs) and demand response (which provides capacity but does not materially displace CO_2 emissions). The overall result would be to more fully utilize the existing plants before inducing new capital investments and to move toward a more decarbonized fleet over time.

Figure 10
New Resource Investments if New Gas CCs are Covered or Uncovered



Notes
Capacity additions shown represent installed capacity. Wind derate is 17% of nameplate capacity.

The real-world impacts of covering or not covering new fossil plants on resource investments are likely to be more consequential than illustrated with these simplified simulations. That is partly because we have not yet examined the full suite of new resource types and emerging technologies that could enter into the market in the future, such as energy efficiency or other low-cost non-emitting resources. Market forces can create incentives for innovation and investment in such resources, but only if all resources compete on a level playing field. These market incentives will not materialize if new gas CCs do not face the same cost of emitting CO_2 as other fossil plants.

> ***"Market forces can create incentives for innovation and investment in low-cost non-emitting resources, but only if all resources compete on a level playing field."***

As another simplification, we have not evaluated the potential for resource retirements. A number of existing nuclear and, to a lesser extent, hydroelectric plants are at risk of retirement across the U.S. Since 2013, nearly 9.5 GW of nuclear plants have either retired or announced plans to retire, and an additional 5.4 GW have been identified as economically at-risk by UBS, Fitch, or Moody's as of September 15, 2015.[47] While hydropower has not experienced the same impacts to date, those resources may face similar economic challenges in the coming decades. As existing hydroelectric facilities age, they face additional reinvestment costs for refurbishment

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47 This does not include San Onofre Units 2 and 3, which retired in 2013 due to equipment failures, or at-risk upstate New York nuclear plants eligible to earn zero-emissions credits under the New York Public Service Commission's Clean Energy Standard. Based on Engblom and Fawad (2015), ABB, Inc. (2016), and retirement announcements at the time of writing.

and relicensing, and many face financial challenges if gas and energy prices remain low. Competitive energy and capacity markets can retain existing non-emitting resources that represent cost-effective CO_2 abatement opportunities, but only if all resources are competing on a level playing field. If new gas CCs have an advantage associated with being treated as a non-emitting resource, then excess investments in new gas CCs may cause existing non-emitting resources to retire. The set-asides program under the EPA's proposed FIP will not mitigate this concern because existing nuclear and hydro plants are not eligible to earn any set-aside awards, and the awards to existing gas CC plants will have a price-suppressive effect in the energy market that will further erode the economics of existing non-emitting plants.

V. Cost and Risk Implications

Introducing resource discrimination into a CO_2 market or competitive wholesale electricity markets can introduce a number of distortions to the pricing and incentives that those markets produce. In this section we discuss the system cost and regulatory risk implications of these distortions.

A. System Costs Per Ton of CO_2 Avoided

A resource-neutral CO_2 market can achieve emissions reductions at the lowest system cost absent other market barriers. Not covering new gas CCs under the CPP would deviate from that principle and thereby introduce economic inefficiencies. Market participants would engage in more costly operating and investment decisions that would shift CO_2 emissions to non-covered plants, without necessarily reducing total actual emissions.

The result is to increase the total system costs for achieving a particular level of CO_2 reductions. Table 3 illustrates this effect by comparing the total system costs incurred for reducing total emissions compared to the Business as Usual case, depending on whether new gas CCs are covered or not covered. We compare the costs per ton of CO_2 avoided in the electricity system across three policy cases: (1) the New Gas CCs Uncovered case that achieves 12% emissions reductions in total (although a higher 18% reduction is achieved if considering only the covered emissions from the existing fleet); (2) the New Gas CCs Covered case that achieves the same 12% emissions reductions, but does so while including new gas CCs under the emissions cap; and (3) the New Source Complement case that achieves a higher 19% reduction in total emissions, consistent with covering new gas CCs under the CPP.

In the New Gas CCs Covered case, covering these plants would create market incentives to pursue the lowest-cost abatement opportunities at an average system cost of $8/ton avoided.[48]

[48] Costs are measured as additional system costs above the Business as Usual case, and include additional production costs and additional investment costs. These reflect only electric system costs and do not account for the societal costs of CO_2 emissions.

Not covering new gas CCs would cost more than twice as much to achieve the same level of CO_2 reductions, resulting in average system costs of $18/ton avoided. The difference in costs would be even greater if we extended our simulation to include considerations of the potential for avoided retirement of at-risk nuclear and hydroelectric resources.

Covering the new gas CCs under the New Source Complement scenario presents a separate set of results, in that it requires a greater level of total CO_2 reductions and therefore imposes higher total costs. However, these reductions are achieved in the most cost-effective manner, at a rate of $11/ton of CO_2 avoided. Compared to the New Gas CCs Uncovered case, the overall result is to achieve 72% more CO_2 abatement at only a 5% increase in total system costs.

Table 3
System Costs of Achieving CO_2 Emissions Reductions

		Emissions and Costs Under Business as Usual	Increase Above (or Decrease Below) Business As Usual		
			New Gas CCs Uncovered	New Gas CCs Covered	New Source Complement
CO_2 Emissions					
Covered CO_2 Emissions	*(million tons/yr)*	116	(21)	(8)	(19)
Total CO_2 Emissions	*(million tons/yr)*	125	(15)	(15)	(24)
System Costs					
Production Costs	*($M/yr)*	$6,170	$18	$116	($352)
Investment Costs	*($M/yr)*	$275	$247	$0	$629
Total System Costs	*($M/yr)*	$6,446	$264	$116	$277
Per Ton Avoided	***($/ton)***		**$18**	**$8**	**$11**

Sources and Notes:
System costs do not necessarily match customer costs, since a portion of the cost increases will be borne by suppliers and a portion will be borne by customers.
All dollars reported in 2016$.

B. Regulatory Risks of Not Covering New Gas CCs

Some state regulators may view the increased costs to achieve the greater level of CO_2 emissions reductions as a cost-effective means of pursuing environmental policy objectives. Other states may be more focused on near-term costs and place less weight on realized CO_2 emissions reductions and may therefore opt to leave new gas CCs uncovered.

This strategy may result in lower near-term costs as long as the new gas CCs remain uncovered, but exposes the state to the risk that the new gas CC exemption will eventually end. The generation fleet might then be built out in a way that emphasizes an over-investment of new gas CCs and the supporting gas pipeline infrastructure, under the assumption that these resources would never be subject to CO_2 emissions costs. Such a system would not be well-prepared to adapt if a CO_2 standard were later applied to those plants. These concerns are amplified in markets facing a large number of plant retirements or high load growth over the coming years, where the market incentives will determine whether those plants will be replaced by CO_2-

emitting gas plants or the non-emitting resources that would be needed under increasingly stringent CO_2 policies.

To illustrate the potential consequences of that scenario, we simulated Scenario 5: Unanticipated Regulation in two steps to reflect a system that: (1) builds a generation fleet consistent with Scenario 2: New Gas CCs Uncovered; and then (2) adapts to a new policy where new plants are covered with the same level of reductions required as in Scenario 4: New Source Complement. Table 4 below summarizes the resulting emissions and the associated system costs. The simulations show that if new gas CCs are covered from the beginning, the market would support investment in more non-emitting resources and enable meeting the CO_2 emissions reductions requirement at a cost of $11/ton avoided. In the alternative Unanticipated Regulation scenario, the system would increase reliance on CO_2-emitting new gas CCs and has fewer non-emitting resources available. The result would be to achieve the same level of CO_2 emissions reductions, but at a higher cost of $19/ton avoided, or 73% more than in the New Source Complement case. The risk of additional costs associated with unanticipated regulation may be significantly higher than estimated here if, for example, the regulation requires CO_2 reductions after 2030 and additional investments in non-emitting generation are needed.

Table 4
System Costs of Achieving CO_2 Emissions Reductions

		Emissions and Costs Under Business as Usual	**Increase Above (or Decrease Below) Business As Usual**	
			New Source Complement	Unanticipated Regulation
CO_2 Emissions				
Covered CO_2 Emissions	*(million tons/yr)*	116	(19)	(19)
Total CO_2 Emissions	*(million tons/yr)*	125	(24)	(23)
System Costs				
Production Costs	*($M/yr)*	$6,170	($352)	$186
Investment Costs	*($M/yr)*	$275	$629	$247
Total System Costs	*($M/yr)*	$6,446	$277	$433
Per Ton Avoided	***($/ton)***		**$11**	**$19**

Sources and Notes:
System costs do not necessarily match customer costs, since a portion of the cost increases will be borne by suppliers and a portion by customers.
All dollars reported in 2016$.

VI. Findings and Recommendations

If new gas CCs are not covered, the electric sector would fall short of the CO_2 reduction goals under the CPP, while incurring higher system costs per ton of CO_2 avoided. Further, the 2030 fleet mix would have proportionally more CO_2-emitting gas CC resources, and proportionally less non-emitting resources such as demand response, efficiency, renewables, hydro, and nuclear. These effects introduce the additional risk that the electricity system would incur even greater costs if the CO_2 emissions from new gas CC plants become covered in the future. In that situation, the large investments in new gas CCs and pipeline infrastructure could become underutilized stranded assets, and additional investments in new renewables and transmission would have to be made in any case. These concerns are amplified in markets facing a large number of plant retirements over the coming years, where the market incentives will determine whether those plants will be replaced largely by CO_2-emitting resources or non-emitting resources.

Based on our analysis of the interactions with wholesale electricity markets, we find a number of strong reasons for choosing to cover new gas CCs when implementing the CPP. Covering new gas CCs under the new source complement will eliminate the discrepancy in treatment and introduce a uniform incentive to avoid CO_2 emissions. The level playing field represented by this approach is consistent with the technology-neutral principles by which wholesale electricity markets are designed to meet energy, capacity, and CO_2 reduction needs at lowest cost.

List of Acronyms

BSER	Best System of Emissions Reductions
CAA	Clean Air Act
CAISO	California Independent System Operator
CC	Combined Cycle
CEIP	Clean Energy Incentive Program
CF	Capacity Factor
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPP	Clean Power Plan
CT	Combustion Turbine
DR	Demand Response
EE	Energy Efficiency
EPA	U.S. Environmental Protection Agency
ERC	Emissions Rate Credit
ERCOT	Electric Reliability Council of Texas
EU ETS	European Emissions Trading System
FIP	Federal Implementation Plan
GHG	Greenhouse Gas
GW	Gigawatt
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
kW	Kilowatt
Lbs	Pounds
MISO	Midcontinent Independent System Operator
MJB&A	MJ Bradley and Associates
MMBtu	Million British Thermal Unit
MW	Megawatt
MWh	Megawatt-Hour
NDRC	Natural Resources Defense Council
NSC	New Source Complement
NYISO	New York Independent System Operator
OBA	Output-Based Allocation

PV	Photovoltaic
RFF	Resources for the Future
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional Transmission Operator
SIP	State Implementation Plan
SPP	Southwest Power Pool
ST	Steam Turbine
TWh	Terawatt-Hour

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Appendix: Simulation Results Detail

Table 5 includes a detailed comparison of results across the model scenarios discussed in this report. Descriptions of each simulation run are included in Section II above.

Table 5
Detailed Summary of Simulation Results

		Scenario Results					Delta Above (Below) Business As Usual			
		Business As Usual	New Gas CCs Uncovered	New Gas CCs Covered	New Source Complement	Unanticipated Regulation	New Gas CCs Uncovered	New Gas CCs Covered	New Source Complement	Unanticipated Regulation
Market Information										
Gas Price	*($/MMBtu)*	$5	$5	$5	$5	$5	$0	$0	$0	$0
Energy Price	*($/MWh)*	$51	$53	$56	$58	$58	$2	$5	$6	$7
Energy Consumption	*(TWh)*	210	210	210	210	210	0	0	0	0
CO_2 Price	*($/ton)*	$0	$11	$12	$15	$19	$11	$12	$15	$19
New Resource Builds (ICAP)										
New Gas CC	*(MW)*	1,718	3,257	1,718	1,177	3,257	1,539	0	(541)	1,539
Wind	*(MW)*	0	0	0	3,758	0	0	0	3,758	0
Demand Response	*(MW)*	1,539	0	1,539	1,386	0	(1,539)	0	(153)	(1,539)
Net Energy Revenues										
Coal	*($/kW-yr)*	$121	$46	$60	$49	$31	($74)	($60)	($72)	($89)
Existing Gas CC	*($/kW-yr)*	$70	$50	$70	$70	$63	($20)	$0	$0	($7)
New Gas CC	*($/kW-yr)*	$70	$87	$70	$70	$63	$17	$0	$0	($7)
Wind	*($/kW-yr)*	$150	$165	$173	$176	$180	$15	$23	$26	$30
CO_2 Emissions										
Covered CO_2 Emissions	*(million tons/yr)*	116	95	108	97	97	(21)	(8)	(19)	(19)
Total CO_2 Emissions	*(million tons/yr)*	125	111	111	101	103	(15)	(15)	(24)	(23)
System Costs										
Production Costs	*($M/yr)*	$6,170	$6,188	$6,287	$5,818	$6,357	$18	$116	($352)	$186
Investment Costs	*($M/yr)*	$275	$522	$275	$904	$522	$247	$0	$629	$247
Total System Costs	*($M/yr)*	$6,446	$6,710	$6,562	$6,723	$6,879	$264	$116	$277	$433
Per Ton Avoided	***($/ton)***						**$18**	**$8**	**$11**	**$19**

Notes:
New resource builds reported at nameplate capacity. All values reported in 2016$.